DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1279

Jon P. Christinidis
(313) 235-7706
Jon.christinidis@dteenergy.com

January 21, 2022

Lisa Felice
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-20836

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter are DTE Electric Company's Application, Proposed Notice of Hearing, Proposed Protective Order, Proposed Nondisclosure Certificates, Testimony and Exhibits. Also attached is the Proof of Service.

Also provided to the MPSC by hand delivery for filing via two external storage drive are DTE Electric Company's Part II – Financial Information materials, Part III –Supplemental Data and electronic files in Excel and Word format. Concurrently with this filing, the parties to Case Nos. U-20162 and U-20561 are being provided all of these materials via the following secure portal link: U-20836 DTE Electric 2022 Rate Case - Public Discovery - All Documents (sharepoint.com).

Very truly yours,

Jon P. Christinidis

Digitally signed by Jon P. Christinidis
Date: 2022.01.21 14:27:43 -05'00'

Jon P. Christinidis

JPC/erb
Attachments
cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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.	))))))	Case No. U-20836

APPLICATION

DTE Electric Company ("Applicant," the "Company" or "DTE Electric"), a corporation organized and existing under and by virtue of the laws of the State of Michigan, with its principal office at One Energy Plaza, Detroit, Michigan 48226, files this Application pursuant to MCL 460.6 et seq., and various Michigan Public Service Commission ("Commission") orders, requesting authority to increase rates, and amend its rate schedules and rules governing the distribution and supply of electric energy. In support of the relief requested in this Application, the Company respectfully represents to the Commission as follows:

1. DTE Electric is owned by DTE Electric Holdings, LLC, which is a wholly-owned subsidiary of DTE Energy providing retail electric service to customers located in Michigan, and is a public utility subject to the jurisdiction of the Commission.

2. The Company is presently serving its electric customers under schedules of rates and charges approved by this Commission in, inter alia, its Order dated May 8, 2020, in Case No. U-20561(the "U-20561 Order").

3. This Application is being filed in accordance with filing requirements contained in the Commission's Orders in Case No. U-18238, dated July 31, 2017 and October 11, 2017.

4. The Company has determined the need for additional annual revenues in the amount of approximately $388 million effective as early as November 10, 2022, in order to recover, among other things, Applicant's increased investments in plant involving generation and the electric distribution system and the associated depreciation and property tax increases. The increased investments and related expenses are offset by lower operation and maintenance ("O&M") expenses.

5. This filing reflects the rationale, spending, timing, and expected customer benefits associated with significant investments in distribution, generation, and customer service. Several of these programs include strategic infrastructure investments in substations, poles, wires, transformers and other electric distribution assets to modernize equipment, support growth in customer demand in specific areas, improve worker and public safety, and reduce the frequency and duration of power outages. In addition, the Company supports the continuation of the multi-year tree trimming "surge" program and the construction of the Blue Water Energy Center.

6. The proposed revenue increase described in this Application is necessary in order to allow the Company to continue to provide safe and reliable electric service, to meet customers' service quality expectations, and to allow the Company a reasonable opportunity to recover its costs of operation, including a reasonable rate of return.

7. The historical test year being used by DTE Electric is the calendar year ended December 31, 2020. This 12-month period was then normalized and adjusted for known and measurable changes, as supported by the Company's witnesses in this case, to arrive at the Company's November 1, 2022 through October 31, 2023 projected test year.

8. DTE Electric's projected rate base of approximately $21.3 billion includes actual net plant and working capital as of December 31, 2020 with projected changes through October 31, 2023 and includes the impact of base capital expenditures and further adjustments for specific major

projects. Major capital projects from 2020 through the projected period ending October 31, 2023 are described in the testimony and exhibits of the Company's witnesses.

9. DTE Electric's testimony and exhibits filed contemporaneously with this Application evidence a need for additional annual revenue beginning November 21, 2022 of approximately $388 million.

10. Attachment 1 to this Application summarizes the Company's request. DTE Electric proposes to allocate the required electric revenue increase among rate classes as set forth on Attachment 2 to this Application. A comparison of typical bills and proposed rates for Residential Service Rate D1 is shown on Attachment 3 to this Application. In addition, the Proposed Draft Notice is included as Attachment 4 to this Application.

Furthermore, DTE Electric is proposing, among other things, certain changes to the Company's tariffs, and rules and regulations, including but not limited to, proposed time of use Rate Schedule D1.11, proposed Rate Schedule D1.12, proposed Rate Schedule D3.5, proposed Rider 21, and proposed amendments to Rider 10, Rider 18, and the Retail Access Service Rider.

11. The Company is also proposing several pilot programs in this filing, which include the following:

- Distribution Operations - Strategic Undergrounding
- Distribution Operations - Deconductoring
- Distribution Operations - Electric Vehicle Charging Demo
- Distribution Operations - Small Solar and Storage Testbed
- Distribution Operations - Non-wire Alternatives
- Generation - Green Hydrogen at Blue Water Energy Center
- Generation - Battery Energy Storage System
- Marketing - Charging Forward eFleets
- Marketing - Charging Forward Expansion
- Marketing - Residential Battery
- Demand Response - Residential Generator
- Demand Response – Battery Storage
- Demand Response – Residential Window Air-conditioning
- Demand Response – Peak Time Savings

12. In Case No. U-20561, the Commission approved the deferral of tree trim surge amounts above the approved O&M expenses as a regulatory asset through 2022. The Company, in this filing, is requesting that the Commission approve surge funding deferral for the calendar years of 2023 and 2024. The Company plans to seek securitization of the deferred asset once it reaches approximately $150 million. The Company is also requesting the Commission approve a change in the "return on" rate it applies to the tree trim surge regulatory asset balance going forward.

13. DTE Electric is also requesting approval of various accounting proposals, including but not limited to, accounting treatment of costs to expand the Company's Charging Forward program; regulatory accounting treatment for certain costs associated with the Time of Use rate offering; proposed accounting for unused Low-Income Assistance/Residential Income Assistance credits; accounting for a pension expense deferral mechanism; a COVID-19 compliance expense regulatory asset; and a customer outage credit regulatory asset.

14. DTE Electric is seeking cost recovery of its variable compensation programs that are used to attract and retain employees with the requisite skills and experience to ensure quality customer service; ensure that DTE Electric's employees' total compensation is externally competitive; and that differentiate total rewards based on organizational and individual contributions. The Company is not seeking to recover the variable compensation for the top five DTE Energy executives.

15. DTE Electric is requesting a return on equity of 10.25% with an overall rate of return of 5.56% after tax, 6.98% pre-tax. The Company is requesting a permanent capital structure of approximately 50% equity and 50% long-term debt. The projected average rate base for the test year is approximately $21.3 billion, which includes an equity base of approximately $8.4 billion.

16. DTE Electric is requesting that the Commission adopt the PSCR base established in the Commission's Order in Case No. U-15244 on January 13, 2009, adjusted for an updated loss factor.

17. In 2016, the Michigan legislature passed and the Governor signed into law 2016 PA 341 which, in the part pertinent to this proceeding, amended MCL 460.1 *et seq.* by adding Section 6w (MCL 460.6w). Act 341 became effective on April 20, 2017 and directed the creation of a state reliability mechanism ("SRM") and capacity charge. DTE Electric has calculated the capacity charge consistent with the methodology used in the Commission's Case No. U-20162 Order dated May 2, 2019.

18. The Company's filing also includes revenue requirements by unit/grouping study (Plant Study) in compliance with the Commission's May 8, 2020 Order in DTE Electric's last main rate case (Case No. U-20561).

19. The Company is filing the direct testimony and exhibits of 31 witnesses concurrently with this Application. The contents, recommendations, revenue and expense items and proposed ratemaking items set forth in those documents are incorporated into this Application by reference.

20. The fact that Applicant may not address an item or position addressed by Applicant in previous cases, or which is presently on appeal before the courts, does not constitute a waiver of such item or position by the Company, or of any rights or positions that the Company may wish to take on these matters in this or any other proceedings before the Commission (now or in the future), or in any other appropriate court or venue.

WHEREFORE, DTE Electric requests that the Commission:

A. Accept this Application for filing;

B. Give such Notice to interested parties as may be required by statute or the Commission's rules;

C. Establish a date, place and time for a prehearing conference;

D. Conduct a hearing on this Application in order to determine the just and reasonable rates, effective as early as November 21, 2022, which will provide the Company a reasonable opportunity to recover its costs of operation, including a reasonable rate of return, in the projected test year and beyond;

E. Approve an additional annual revenue increase effective as soon as possible in the projected test year as described herein;

F. Approve the Company's proposed capital structure and return on equity;

G. Grant the Company's request for tree trimming expenditures and the associated request for regulatory asset treatment through 2024;

H. Approve new rates effective as early as November 10, 2022 in the manner described in this Application, the accompanying Attachments and the Company's Direct Testimony and Exhibits;

I. Grant the Company's request to approve the PSCR base;

J. Approve the Company's proposals to implement certain customer rate schedules and tariffs;

K. Approve recovery of the Company's generation investments;

L. Approve recovery of the Company's investments related to the strengthening of the Company's distribution system and reliability improvements;

M. Approve all proposed pilot programs as requested by the Company;

N. Approve all proposed regulatory accounting treatments as requested by the Company.

O. Approve a capacity charge based on the methodology established in Case No. U-

20162 and the capacity-related costs approved in this proceeding;

P. Grant any other relief described in this Application as requested by the Company;

Q. Grant Applicant such further additional relief, as the Commission may deem suitable and appropriate.

Respectfully Submitted,

DTE ELECTRIC COMPANY

By: Marco A. Bruzzano Digitally signed by Marco A. Bruzzano Date: 2022.01.21 14:29:12 -05'00'

Marco A. Bruzzano
Senior Vice President – Corporate Strategy
& Regulatory Affairs

DTE ELECTRIC COMPANY
Legal Department

By: Jon P. Christinidis Digitally signed by Jon P. Christinidis Date: 2022.01.21 14:30:21 -05'00'

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One Energy Plaza, 1635 WCB
Detroit, MI 48226
(313) 235-7706

Dated: January 21, 2022

Attachment 1

MPSC Case No. U-20836

DTE Electric Company

Electric Revenue Deficiency by Major Component

($ Millions)

	(a)	(b)
Line	Description	Projected Revenue Deficiency (1)
1	Rate Base (Plant Investment - Return On & Of, plus Property Taxes)	$ 409
2	Capital Structure	38
3	O&M	(26)
4	Sales Margin	(42)
5	Other	9
6	Total Requested Rate Relief	$ 388

(1) Revenue Deficiency calculated from last approved rate case U-20561

Attachment 2

MPSC Case No. U-20836
DTE Electric Company
Summary of Present and Proposed Revenue by Rate Schedule

Line No.	(a) Rate Schedule	(b) Total Present Revenue ($000's)	(c) Total Proposed Revenue ($000's)	(d) Total Net Increase/ (Decrease) ($000's)	(e) Total Net Increase/ (Decrease) (%)
1	D1/D1.6 Residential	$2,445,134	$2,657,170	$212,036	8.7%
2	D1-A TOU Pilot	$8,787	$9,522	$735	8.4%
3	D1-B TOU Pilot	$8,823	$9,562	$738	8.4%
4	D1.1 Int. Air	$53,972	$59,442	$5,469	10.1%
5	D1.2 TOD	$27,857	$30,660	$2,803	10.1%
6	D1.7 TOD	$15,244	$17,089	$1,844	12.1%
7	D1.8 Dynamic	$37,922	$41,493	$3,571	9.4%
8	D1.9 Elec. Vehicle	$925	$1,018	$93	10.0%
9	D2 Elec. Space Heat	$46,003	$49,800	$3,797	8.3%
10	D5 Res. Water Ht.	$14,983	$16,762	$1,779	11.9%
11	Total Residential	$2,659,651	$2,892,516	$232,866	8.8%
12					
13	**Secondary**				
14	D1.1 Int. Air	$659	$714	$55	8.3%
15	D1.7 TOD	$1,071	$1,187	$115	10.8%
16	D1.8 Dynamic	$133	$145	$12	8.7%
17	D 1.9 Elec Vehicle	$7	$8	$1	8.2%
18	D3/D3.5 Gen. Serv.	$932,920	$1,008,757	$75,836	8.1%
19	D3.1 Unmetered	$10,055	$10,762	$707	7.0%
20	D3.2 Sec. Educ.	$43,517	$49,764	$6,247	14.4%
21	D3.3 Interruptible	$8,143	$8,914	$771	9.5%
22	D4 Lg. Gen. Serv.	$259,936	$272,810	$12,874	5.0%
23	D5 Com. Wat. Ht.	$713	$789	$76	10.7%
24	E1.1 Eng. St. Ltg.	$957	$1,051	$94	9.8%
25	R7 Greenhs. Ltg.	$408	$452	$44	10.9%
26	R8 Space Cond.	$8,602	$9,351	$749	8.7%
27	Total Secondary	$1,267,121	$1,364,702	$97,581	7.7%
28					
29	**Primary**				
30	D11 Prim. Supply	$976,184	$1,023,389	$47,205	4.8%
31	D12 Exp. Lrg Cust	$0	$0	$0	-
32	D6.2 Pri. Educ.	$42,647	$44,811	$2,164	5.1%
33	D8 Int. Primary	$42,973	$45,406	$2,433	5.7%
34	D10 El.Schools	$2,258	$2,372	$114	5.1%
35	R1.1 Alt. Mtl. Melt.	$4,253	$4,415	$162	3.8%
36	R1.2 El. Pr. Htg.	$34,633	$36,624	$1,990	5.7%
37	R3 Standby	$11,882	$12,753	$871	7.3%
38	R10 Int. Supply	$69,135	$62,911	($6,224)	(9.0%)
39	Total Primary	$1,183,965	$1,232,681	$48,716	4.1%
40					
41	**Other**				
42	D9 Protective Ltg.	$10,790	$10,101	($689)	(6.4%)
43	E1 Muni Street Ltg	$52,923	$62,439	$9,517	18.0%
44	E2 Traffic Lights	$4,947	$5,180	$233	4.7%
45	Total Other	$68,659	$77,720	$9,061	13.2%
46					
47	**Total All Classes**	$5,179,395	$5,567,620	$388,224	7.5%

Attachment 3

MPSC Case No. U-20836
DTE Electric Company
Comparison of Typical Bills Under Present and Proposed Rates
Residential Service Rate D1

	(a)	(b)	(c)	(d)	(e)
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent
1	100	$24.25	$25.90	$1.65	6.79%
2	200	$40.13	$43.42	$3.29	8.21%
3	300	$56.01	$60.95	$4.94	8.82%
4	400	$71.89	$78.47	$6.59	9.16%
5	500	$87.76	$96.00	$8.24	9.38%
6	600	$105.43	$115.06	$9.63	9.13%
7	700	$123.29	$134.28	$10.99	8.92%
8	800	$141.15	$153.51	$12.36	8.76%
9	900	$159.02	$172.74	$13.72	8.63%
10	1,000	$176.88	$191.97	$15.09	8.53%
11	1,500	$266.19	$288.11	$21.91	8.23%
12	2,000	$355.51	$384.25	$28.74	8.08%
13	4,000	$712.76	$768.80	$56.04	7.86%

ATTACHMENT 4

PROPOSED

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
NOTICE OF HEARING

FOR THE ELECTRIC CUSTOMERS OF
DTE ELECTRIC COMPANY
CASE NO. U-20836

- DTE Electric Company may increase its annual base electric revenues by approximately $388 million above existing base electric rate levels along with other requested relief if the Michigan Public Service Commission (Commission) approves its request.

- A TYPICAL RESIDENTIAL CUSTOMER'S AVERAGE ELECTRIC BILL MAY BE INCREASED BY UP TO $10.31 PER MONTH, IF THE MICHIGAN PUBLIC SERVICE COMMISSION APPROVES THE REQUEST.

- The information below describes how a person may participate in this case.

- You may call or write DTE Electric Company, One Energy Plaza, Detroit, Michigan 48226, 1-800-477-4747, for a free copy of its application, testimony and exhibits. Any person may review the application, testimony and exhibits at the offices of DTE Electric Company or on the Commission's website at: michigan.gov/mpscedockets

- A pre-hearing will be held:

DATE/TIME:	**__________________, 2022, at 10:00 a.m.**
BEFORE:	**Administrative Law Judge _________________**
LOCATION:	**Video/Teleconferencing**
PARTICIPATION:	Any interested person may participate. Persons needing any assistance to participate should contact the Commission's Executive Secretary at (517) 284-8090, or by email atmpscedockets@michigan.gov in advance of the hearing.

The Michigan Public Service Commission (Commission) will hold a pre-hearing to consider DTE Electric Company's January 10, 2022 application to increase its annual base electric revenues by approximately $388 million along with other requested relief.

DTE Electric Company's Application states that the requested increase is required to recover the costs associated with significant investments in distribution, generation, and customer service. Several of these programs include strategic infrastructure investments in electric distribution assets to modernize equipment, support growth in customer demand in specific areas, improve worker and public safety, and reduce the frequency and duration of power outages. In addition, DTE Electric Company seeks to recover the costs of continuing its multi-year tree trimming "surge" program and the construction of the Blue Water Energy Center.

DTE Electric Company's requested relief also includes certain changes to its tariffs, and rules and regulations, including but not limited to proposed time of use Rate Schedule D1.11, proposed Rate Schedule D1.12, proposed Rate Schedule D3.5, proposed Rider 21, and proposed amendments to Rider 10, Rider 18, and the Retail Access Service Rider. The Application also requests approval of capital structure cost changes, various accounting proposals and identifies several proposed pilot programs associated with its distribution system, generation, electric vehicles, and electric demand response. In total, DTE Electric Company's Application seeks Commission approval for additional annual revenues of approximately $388 million based upon a November 1, 2022 through October 31, 2023 projected test year with rates effective as early as November 10, 2022.

The chart below summarizes DTE Electric Company's proposed base revenue increases.

SUMMARY OF PROPOSED BASE REVENUE INCREASES

DTE Electric Company
Summary of Proposed
Base Electric Revenue Increase /(Decrease)

Rate Schedule	Total Present Revenue ($000's)	Total Proposed Revenue ($000's)	Total Net Increase/ (Decrease) ($000's)	Total Net Increase/ (Decrease) (%)
D1/D1.6 Residential	$2,445,134	$2,657,170	$212,036	8.7%
D1-A TOU Pilot	$8,787	$9,522	$735	8.4%
D1-B TOU Pilot	$8,823	$9,562	$738	8.4%
D1.1 Int. Air	$53,972	$59,442	$5,469	10.1%
D1.2 TOD	$27,857	$30,660	$2,803	10.1%
D1.7 TOD	$15,244	$17,089	$1,844	12.1%
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D1.9 Elec. Vehicle	$925	$1,018	$93	10.0%
D2 Elec. Space Heat	$46,003	$49,800	$3,797	8.3%
D5 Res. Water Ht.	$14,983	$16,762	$1,779	11.9%
Total Residential	$2,659,651	$2,892,516	$232,866	8.8%

Secondary				
D1.1 Int. Air	$659	$714	$55	8.3%
D1.7 TOD	$1,071	$1,187	$115	10.8%
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D3.2 Sec. Educ.	$43,517	$49,764	$6,247	14.4%
D3.3 Interruptible	$8,143	$8,914	$771	9.5%
D4 Lg. Gen. Serv.	$259,936	$272,810	$12,874	5.0%
D5 Com. Wat. Ht.	$713	$789	$76	10.7%
E1.1 Eng. St. Ltg.	$957	$1,051	$94	9.8%
R7 Greenhs. Ltg.	$408	$452	$44	10.9%
R8 Space Cond.	$8,602	$9,351	$749	8.7%
Total Secondary	$1,267,121	$1,364,702	$97,581	7.7%

Rate Schedule	Total Present Revenue ($000's)	Total Proposed Revenue ($000's)	Total Net Increase/ (Decrease) ($000's)	Total Net Increase/ (Decrease) (%)
Primary				
D11 Prim. Supply	$976,184	$1,023,389	$47,205	4.8%
D12 Exp. Lrg Cust	$0	$0	$0	-
D6.2 Pri. Educ.	$42,647	$44,811	$2,164	5.1%
D8 Int. Primary	$42,973	$45,406	$2,433	5.7%
D10 El.Schools	$2,258	$2,372	$114	5.1%
R1.1 Alt. Mtl. Melt.	$4,253	$4,415	$162	3.8%
R1.2 El. Pr. Htg.	$34,633	$36,624	$1,990	5.7%
R3 Standby	$11,882	$12,753	$871	7.3%
R10 Int. Supply	$69,135	$62,911	($6,224)	(9.0%)
Total Primary	$1,183,965	$1,232,681	$48,716	4.1%
Other				
D9 Protective Ltg.	$10,790	$10,101	($689)	(6.4%)
E1 Muni Street Ltg	$52,923	$62,439	$9,517	18.0%
E2 Traffic Lights	$4,947	$5,180	$233	4.7%
Total Other	$68,659	$77,720	$9,061	13.2%
Total All Classes	$5,179,395	$5,567,620	$388,224	7.5%

All documents filed in this case shall be submitted electronically through the Commission's E-Dockets website at: michigan.gov/mpscedockets. Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in Word or PDF format, as an attachment to an email sent to: mpscedockets@michigan.gov. If you require assistance prior to e-filing, contact Commission staff at (517) 284-8090 or by email at: mpscedockets@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by _____________, 2022. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon DTE Electric Company's attorney, Jon P. Christinidis, One Energy Plaza, 1635 WCB, Detroit, MI 48226.

The prehearing is scheduled to be held remotely by video conference or teleconference. Persons filing a petition to intervene will be advised of the process to participate in the hearing.

Any person wishing to participate without intervention under Mich Admin Code, R 792.10413 (Rule 413), or file a public comment, may do so by filing a written statement in this docket. The written statement may be mailed or emailed and should reference Case No. U-20836. Statements may be emailed to: mpscedockets@michigan.gov. Statements may be mailed to: Executive Secretary, Michigan Public Service Commission, 7109 West Saginaw Hwy., Lansing, MI 48917. All information submitted to the Commission in this matter becomes public information, thus available on the Michigan Public Service Commission's website, and subject to disclosure. Please do not include information you wish to remain private. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

Requests for adjournment must be made pursuant to the Michigan Office of Administrative Hearings and Rules R 792.10422 and R 792.10432. Requests for further information on adjournment should be directed to (517) 284-8130.

A copy of DTE Electric Company's application may be reviewed on the Commission's website at: michigan.gov/mpscedockets, and at the office of DTE Electric Company, One Energy Plaza, Detroit, MI 48226. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

The Utility Consumer Representation Fund has been created for the purpose of aiding in the representation of residential utility customers in various Commission proceedings. Contact the Chairperson, Utility Consumer Participation Board, Department of Licensing and Regulatory Affairs, P.O. Box 30004, Lansing, Michigan 48909, for more information.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and Parts 1 & 4 of the Michigan Office of Administrative Hearings and Rules, Mich. Admin Code, R 792.10106 and R 792.10401 through R 792.10448.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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	))))))	Case No. U-20836

PROPOSED PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that DTE Electric Company ("Applicant") or any other Party discloses to another Party during the course of this proceeding. The Applicant or other Party disclosing Protected Material is referred to as the "Disclosing Party"; the recipient is the "Receiving Party" (defined further below). The intent of this Protective Order is to protect non-public, confidential information and materials so designated by the Applicant or by any other party, which information and materials contain confidential, proprietary, or commercially sensitive information. This Protective Order defines "Protected Material" and describes the manner in which Protected Material is to be identified and treated. Accordingly, it is ordered:

I. "Protected Material" and Other Definitions

A. For the purposes of this Protective Order, "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information provided in Disclosing Party's Exhibits, discovery or audit responses, any witness' related exhibit and testimony, and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. Trade secrets or confidential, proprietary, or commercially sensitive information provided in response to discovery, in response to an order issued by the presiding hearing officer or the Michigan Public Service Commission ("MPSC" or the "Commission"), in testimony or exhibits filed later in this case, or in arguments of counsel;

    a. Examples of such trade secrets, confidential, proprietary, or commercially sensitive information include, but are not limited to, information regarding compensation, generation, transmission and distribution facilities and related equipment, infrastructure, energy market projections or assumptions, forecasts, gas conversion analyses, sensitivity analyses, revenue requirement analyses, or financial arrangements including but not limited to those set forth in contracts.

    b. Exclusions include Critical Energy Infrastructure Information ("CEII"), technical data subject to U.S. export control laws and regulations, including but not limited to 10 C.F.R. Part 810 *et. seq*., North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) material and information, DTE Electric distribution system information and operational data including Supervisory Control and Data Acquisition (SCADA) information, confidential Midcontinent Independent System Operator (MISO) and ITC Holdings Corp and/or its affiliate companies' information in the possession of DTE Electric Company, and information regarding Cyber Security which shall not be disclosed pursuant to this Protective Order or under any other circumstance. No individual DTE Energy employee's compensation benefits or other personal information is relevant in this proceeding. No individual DTE Energy employee's compensation, benefits or other personal information shall be required to be disclosed in this proceeding in the course of a hearing, through discovery, under this Protective Order, or otherwise.

2. To the extent permitted, information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the Disclosing Party is a licensee, that is subject to any confidentiality or non-transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third- party licensor to disclose consistent with the terms and conditions of this Protective Order.

3. Where protection from all means of disclosure is demanded in writing by a vendor of commercially-available market analyses and/or studies concerning

employee compensation levels and such written demand is submitted to the Commission by DTE Electric, no Party shall obtain access to such commercially-available market analyses and/or studies concerning employee compensation levels until the Commission promises confidentiality for such market analyses and/or studies concerning employee compensation levels in writing, the Chairman of the Commission authorizes that promise of confidentiality in writing and the Commission thereafter through issuance of an order grants Protected Materials involving such market analyses and/or studies concerning employee compensation levels exemption from disclosure under the Michigan Freedom of Information Act ("FOIA") as *"Trade secrets or commercial or financial information"* pursuant to MCL 15.243(1)(f) and the material marked "CONFIDENTIAL-SUBJECT TO PROTECTIVE ORDER IN CASE NO. U-20836 – <u>EXEMPT FROM PUBLIC DISCLOSURE UNDER THE MICHIGAN FREEDOM OF INFORMATION ACT MCL 15.243(1)(f)</u>". If the AG or any other Party to this proceeding is itself subject to disclosure requirements under FOIA and wishes to obtain Protected Materials involving market analyses and/or studies concerning employee compensation levels that have been exempted by the Commission from disclosure under FOIA, the AG or other Party, in addition to executing a Non-Disclosure Certificate, must also exempt such Protected Materials from disclosure under FOIA prior to obtaining such Protected Materials.

4. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a power purchase agreement or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process (*i.e.*, before the Disclosing Party has entered into a power purchase agreement or selected a contractor).

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;

2. Information received from a third party free to disclose the information without restriction;

3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;

4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or

5. Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. The parties agree that this protective order is insufficient to protect particularly sensitive commercial information regarding current contract negotiations and contract-re-negotiations and such information shall not be disclosed without agreement of the parties or further proceedings regarding this information including, but not limited to, a determination by the presiding officer whether, and if so to what extent, the material is to be disclosed, and any additional protections that may be necessary on a case by case basis. The parties reserve the right to exhaust any appeals to the Commission and any court or appellate court of competent jurisdiction prior to making any ordered disclosure.

D. "Party" refers to the Applicant, MPSC Staff ("Staff"), Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in Case No. U-20836 under the Commission's Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

E. "Receiving Party" means any Party to this proceeding who requests or receives access to Protected Material, subject to the requirement that each Reviewing Representative sign a Nondisclosure Certificate attached to this Protective Order as Attachment 1.

F. "Reviewing Representative" means a person who has signed a Nondisclosure Certificate and who is:

1. An attorney who has entered an appearance in this proceeding for a Receiving Party;

2. An attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.F.1;

3. An expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or

4. An employee or other representative of a Receiving Party with significant responsibility in this case.

A Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

G. “Nondisclosure Certificate” means the certificate attached to this Protective Order as Attachment 1, which is signed by a Reviewing Representative who has been granted access to Protected Material and agreed to be bound by the terms of this Protective Order.

II. Access to and Use of Protected Material

A. This Protective Order governs the use of all Protected Material that is marked as required by Paragraph III.A and made available for review by the Disclosing Party to any Receiving Party or Reviewing Representative. This Protective Order protects: (i) the Protected Material; (ii) any copy or reproduction of the Protected Material made by any person; and (iii) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of a Receiving Party shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorized to have access subject to the provisions of this Protective Order.

B. Protected Material shall be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party may authorize access to, and use of, Protected Material by a Reviewing Representative identified by the Receiving Party, subject to Paragraphs III and V below, only as necessary to analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. These individuals shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, the Disclosing Party and the Receiving Party will attempt to reach an agreement to accommodate that Receiving Party's request to review Protected Material. If no agreement is reached, then either the Disclosing Party or the Receiving Party may submit the dispute to the presiding hearing officer. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding hearing officer.

D. Before reviewing any Protected Material, including copies, reproductions, and copies of notes of Protected Material, a Receiving Party and Reviewing Representative shall sign a copy of the Nondisclosure Certificate (Attachment 1 to this Protective Order) agreeing to be bound by the terms of this Protective Order. The Reviewing Representative shall also provide a copy of the executed Nondisclosure Certificate to the Disclosing Party.

E. No person who is afforded access to any Protected Material by reason of this Order shall disclose the Protected Material to anyone not specifically authorized to receive such information pursuant to the terms of this Order. Nor shall such persons use the Protected Material in any manner inconsistent with this Order. All persons afforded access to Protected Material pursuant to this Order shall keep the Protected Material secure in accordance with the purposes and intent of this Order and shall adopt all reasonable precautions to assure continued confidentiality, including precautions against unauthorized copying, use, or disclosure thereof.

F. A party seeking or intending to disclose in or on the public record information taken directly from materials identified as Protected Material must – before actually disclosing the information – do one of the following: (a) contact DTE Electric's counsel of record and obtain written permission to place the information in the public record, (b) take affirmative steps to confirm and actually confirm that the information is otherwise public information and within an exclusion in section 7 of this Order and comply with the notice provisions in section 7, or (c) challenge the confidential nature of the Protected Material and obtain a ruling under section 10 that the information is not confidential and may be disclosed in or on the public record

G. Even if no longer engaged in this proceeding, every person who has signed a Nondisclosure Certificate continues to be bound by the provisions of this Protective Order. The obligations under this Protective Order are not extinguished or nullified by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order.

H. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding hearing officer shall have access to all Protected Material that is submitted to the Commission under seal without the need to sign the Nondisclosure Certificate.

I. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

J. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

III. Procedures

A. The Disclosing Party shall mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-20836." Software executable files containing protected material may not be capable of being marked with the foregoing required protective language. The inability to mark software executable files containing protected material with such protective language shall not diminish the requirements of this Protective Order. It shall be sufficient if the medium used to deliver software executable files containing protected information is marked with the required protective language. However, any output from the software executable files containing protected material that is generated only as a reproducible document, whether electronic or non-electronic, that is capable of being marked with the required protective language, shall be marked by the party who generated the output with such protective language and subject to the requirements of this Protective Order. If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL – SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-20836." Simultaneously, identical documents and materials, with the

Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;

2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material; and

3. Copies of the documents filed with the MPSC which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, shall be marked or identified as, "CONFIDENTIAL - SUBJECT TO PROTECTIVE ORDER IN CASE NO. U-20836" and shall be maintained in a separate portion of the record under seal, segregated in the files of the Commission, and withheld from inspection by any person not bound by the terms of this Order.

C. The Protected Material subject to this Order shall be shielded from disclosure to the extent permitted by law. If any person files a Freedom of Information Act ("FOIA") request with the Commission seeking access to documents subject to this Order, then the Commission's Executive Secretary shall notify DTE Electric as soon as reasonably practicable and DTE Electric may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. If the Commission denies a claim of confidentiality, in whole or in part, then the Commission shall give notice to DTE Electric at least five (5) business days prior to the Commission's contemplated disclosure in response to the request. The notice shall briefly explain why DTE Electric's objections to disclosure were not sustained by the Commission. In the event that the FOIA requester commences suit against the Commission to compel disclosure of a document for which privilege is claimed, the Commission shall immediately notify DTE Electric of the suit.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. In response to a motion, the Commission or the presiding hearing officer in this case may revoke a document's protected status after notice and hearing. If the presiding hearing officer revokes a document's protected status, then the document loses its protected status after 14 days unless a Party files an application for leave to appeal the ruling to the Commission within that time period. Any Party opposing the application for leave to appeal shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. If an application is filed, then the information will continue to be protected from disclosure until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired.

B. If a document's protected status is challenged under Paragraph IV.A, the Receiving Party challenging the protected status of the document shall explicitly state its reason for challenging the confidential designation. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

Protected Material remains the property of the Disclosing Party and only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order in Case No. U-20836 or until the MPSC has ruled on all petitions for rehearing in this case (if any). However, an attorney for a Receiving Party who has signed a Nondisclosure Certificate and who is representing the Receiving Party in an appeal from an MPSC final order in this case may retain copies of Protected Material until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired. On or before the time specified by the preceding sentences, the Receiving Party shall return to the Disclosing Party all Protected Material in its possession or in the possession of its Reviewing Representatives-including all copies and notes of Protected Material-or certify in writing to the Disclosing Party that the Protected Material has been destroyed.

VI. Limitations and Disclosures

The provisions of this Protective Order do not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.1 through I.B.5. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must-before actually disclosing the information-do one of the following: (i) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or (ii) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

VII. Remedies

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes immediately notifying the MPSC, the presiding hearing officer, and the Disclosing Party, in writing, of the identity of the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

____
Administrative Law Judge

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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	))))))	Case No. U-20836

NONDISCLOSURE CERTIFICATE

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issued in Case No. U-20836, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by the terms of the Protective Order. I understand that the substance of the Protected Material (as defined in the Protective Order), any notes from Protected Material, or any other form of information that copies or discloses Protected Material, shall be maintained as confidential and shall not be disclosed to anyone other than in accordance with the Protective Order.

Reviewing Representative

Date: ____________ ____

Title: _______________________________________

Representing: ________________________________

____
Printed Name

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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	))))))	Case No. U-20836

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on January 21, 2022, she served a copy of DTE Electric Company's Application, Proposed Prehearing Notice, Proposed Protective Order, Proposed Nondisclosure Certificates, Testimony and Exhibits, DTE Electric Company's Part II – Financial Information materials and Part III –Supplemental Data materials (are being provided via a secure portal link) in the above captioned matter, via electronic mail and secure portal link, upon the persons listed on the attached service list.

Estella R. Branson
Digitally signed by Estella R. Branson
Date: 2022.01.21 14:31:38 -05'00'

ESTELLA R. BRANSON

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ADELLA F. CROZIER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ADELLA F. CROZIER

Line
No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Adella F. Crozier (she/her/hers). My business address is One Energy Plaza, Detroit, MI 48226. I am employed by DTE Energy Corporate Services LLC, a subsidiary of DTE Energy Company (DTE Energy), within Regulatory Affairs as a Director.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Science degree in Metallurgical Engineering from Iowa State University and a Master of Business Administration degree from the University of Chicago. I have also completed several Company sponsored courses and attended various seminars to further my professional development.

Q4. What work experience do you have?

A4. Prior to my employment at DTE Energy, I was employed by LTV Steel Company (LTV) in various roles including Metallurgical and Quality Control Engineer in positions of increasing responsibility for different product lines. My last role with LTV was as Product Manager in the Sales and Marketing Department. In this role, I had responsibility for managing the relationship between the Sales and Marketing Department and one of LTV's major plants. As part of my responsibilities, I ran financial and engineering analyses related to product line offerings.

Q5. What has been your work experience at DTE Energy?

Line
No.

A5. I joined DTE Energy in 2003 as a Technological Specialist in the Fossil Generation Department's Engineering Support Organization. In 2004, I was promoted to Supervisor – Mechanics and Metallurgy. In 2005, I joined the Regulatory Affairs Department as Manager of Special Projects. In this role, I assisted the Environmental Affairs Department with their portions of Detroit Edison's general rate case filings and served as a member of several workgroups related to Governor Granholm's 21st Century Energy Plan and Capacity Need Forum. I helped with the Company's implementation of Michigan's 2008 energy legislation, particularly those areas related to energy optimization. I managed several Detroit Edison energy optimization filings as well as provided witness testimony regarding the revenue requirement of several energy optimization plans and reconciliations. During this time, I also assisted the case managers of general rate cases.

I was promoted to Manager of Electric Regulatory Strategy in 2013 where my responsibilities included research of regulatory matters. My team provided management of DTE Electric's general rate cases.

I was promoted to Director within Regulatory Affairs in 2016. In this role, my team is currently responsible for managing the Company's state filings and activities at the Michigan Public Service Commission (MPSC or Commission). Members of my team also provide various research activities pertinent to our electric utility and provide cost of service and revenue requirement modeling.

Q6. Have you been involved in any prior regulatory proceedings?

A6. Yes. I sponsored testimony in the following DTE Electric cases:

Line No.		
1	U-15806	Detroit Edison's Energy Optimization (EO) Plan
2	U-15806 A	Detroit Edison's EO Amended Plan
3	U-16358	Detroit Edison's 2009 EO Reconciliation
4	U-16359	Detroit Edison's 2010 EO Reconciliation
5	U-16737	Detroit Edison's 2011 EO Reconciliation
6	U-20561	DTE Electric 2019 Rate Case
7	U-18232	DTE Electric 2020 Renewable Energy Plan (REP) Amendment
8	U-18091	DTE Electric 2021 PURPA Avoided Costs

Line
No.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to:

- Provide an overview of the Company's entire general electric rate case including a summary of the drivers for filing this case at this time, the amount of the Company's projected revenue deficiency starting November 1, 2022, and a summary of the impacts on the Company's business from the novel coronavirus (COVID-19) pandemic;
- Review the overall methodology used to develop the Company's projected test year amounts in this case;
- Address the following Company ratemaking and policy considerations which are included in my testimony to propose unique or different ratemaking treatments, respond to prior Commission orders, highlight noteworthy regulatory issues, or address topics of interest expressed by stakeholders:
    - Request for changes to the Commission approved ratemaking treatment for tree trimming surge costs as well as the Company's future securitization of costs associated with the Company's tree trimming surge;
    - Changes to the R10 production cost allocation methodology;
    - Description and support for the corporate memberships included for ratemaking as ordered in the Company's last general rate case, U-20561;
    - The Company's proposed treatment of customer outage credits given the Commission's recently proposed revisions to the ruleset governing these credits.
- Introduce the Company's other witnesses.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibit:

Exhibit	Schedule	Description
A-27	Q1	Corporate Memberships

Q9. Was this exhibit prepared by you or under your direction?

A9. Yes, it was.

Case Overview

Q10. Can you briefly describe DTE Electric?

A10. Yes. DTE Electric generates, purchases, distributes, and sells electricity to approximately 2.2 million customers in southeastern Michigan. The Company has over 11,000 megawatts of generation capacity including, coal, wind, solar, nuclear, hydroelectric pumped storage, and natural gas. DTE Electric delivers electricity to its customers over approximately 31,000 miles of overhead distribution lines and 16,600 miles of underground distribution lines across a service territory that encompasses 7,600 square miles. Founded in 1903, DTE Electric is the largest electric utility in Michigan and one of the largest in the nation.

Q11. What is DTE Electric's overall business objective?

A11. DTE Electric's overall business objective is to provide safe, reliable, clean, and cost-effective electric service to its customers and deliver reasonable and appropriate compensatory returns to DTE Energy shareholders while maintaining its financial health. Providing safe, reliable, and cost-effective service to its

Line No.

customers means that DTE Electric: 1) provides quality customer service, 2) operates its system safely, and 3) delivers electric service reliably at a reasonable cost.

Q12. How do the requests in this general rate case filing support DTE Electric's overall business objectives?

A12. This rate case represents a major commitment to reliability and innovation. The Company is seeking approval of significant infrastructure investments to improve the reliability and resilience of its electric distribution system as detailed in its recent Distribution Grid Plan filed in Case No. U-20147. This involves redesigning and rebuilding antiquated infrastructure, modernizing how the electric grid is monitored and operated, and performing preventive and proactive maintenance and tree trimming at standards that reflect today's operating conditions, including increased system hardening to withstand more extreme weather. These investments will not only reduce how often and how long customers experience power outages but will also enable the Company to support greater optionality for customers in adopting new technologies such as batteries, solar, and electric vehicles (EVs).

To support innovation during this period of transformational change in the energy industry, the Company is also proposing new technology deployments, including enhanced information technology capabilities to improve the customer experience; energy storage in the form of batteries and green hydrogen; non-wires alternatives; and expanded programs to support deployment of EV and volt-var optimization/conservation voltage reduction. The generation fleet is expanding to cleaner resources with the expected start-up of the Company's new natural gas plant,

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Blue Water Energy Center (BWEC), in the second quarter of 2022 and continuing the retirement of our Tier 2 coal fleet. DTE Electric has retired four of its coal-fired facilities (Marysville, Harbor Beach, Conners Creek and River Rouge) and plans to retire two of its four remaining coal plants – St. Clair and Trenton Channel – in 2022.

Q13. Why has DTE Electric filed this general rate case at this time?

A13. The Company carefully considered several factors before determining the need to file this general electric rate case. Our customers expect and deserve safe and reliable service. As discussed above, DTE Electric is implementing a major capital investment program to improve reliability and resilience, most notably for the distribution system. However, the Company's existing rates and projected electricity sales cannot sustain this level of infrastructure investment without a rate increase. The only way that DTE Electric can adequately provide the required service levels that our customers desire and deserve is by being financially healthy. The Company's current authorized rates are not expected to provide DTE Electric with adequate revenues to make necessary infrastructure investments while providing a reasonable opportunity to earn a fair return on equity beginning in November 2022.

Q14. What are the measures used to determine the Company's financial health?

A14. Maintaining DTE Electric's financial health requires that the Company has a reasonable opportunity to earn its cost of capital, that the Company has a well-balanced capitalization (no less than 50% equity to total permanent capitalization), and that the Company is able to maintain its A/Aa3/A$^+$ credit ratings for senior

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secured debt from the three major rating agencies. These preconditions are necessary to ensure DTE Electric has full access to capital markets at reasonable rates, terms and conditions regardless of business cycle timing or industry conditions. As discussed by Company Witness Mr. Lepczyk, without full access to capital markets at reasonable terms and conditions, the cost of providing utility services can increase significantly.

Q15. Why is the Company's financial health important for customers?

A15. To attract the capital necessary for the prudent operation and maintenance of our facilities, the Company must be able to demonstrate its ongoing financial health. Inadequate rates will ultimately result in higher financing costs and have a significant negative impact on our ability to adequately serve our customers and maintain the integrity of our electric distribution and generation assets. This negative impact will occur because more dollars are required to support our financing costs, and therefore, are not available for system maintenance or customer service. Similarly, inadequate funding for capital and maintenance programs, over time, will result in the deterioration of DTE Electric's generation and distribution infrastructure, ultimately resulting in reduced system reliability and service quality.

Thus, it is essential to DTE Electric's financial health that the ultimate cost that customers are asked to pay for Company services generates sufficient cash flow from operations to fund the necessary capital expenditures to improve service and pay a reasonable dividend.

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Q16. Do the financial stability of DTE Electric and its continued implementation of infrastructure maintenance and investment programs provide additional benefits to customers and the region?

A16. Yes. DTE Electric has an important positive economic impact on the communities it serves. DTE Electric is one of the largest employers in Southeast Michigan with over 4,800 employees. Through the Pure Michigan Business Connect campaign, the Company utilizes the services of numerous local contractors and vendors. DTE Energy spent over $2 billion with Michigan based companies in 2020. Through property taxes, DTE Electric contributes to the financial health of local communities. In the historical test year, DTE Electric paid approximately $250 million in property taxes to Michigan communities. To maintain facilities, comply with various regulations, implement our Distribution Grid Plan, and continue the transformation of our generation fleet, DTE Electric continues to make major capital investments in the communities in which it serves and operates. Thus, DTE Electric supports additional job growth opportunities and provides incremental tax revenue for our local communities.

COVID-19

Q17. In what ways did the Company support and protect both customers and employees in response to COVID-19?

A17. DTE Electric undertook many actions to safeguard its customers and employees during the COVID-19 crisis. In the initial months of the pandemic, DTE Electric suspended disconnections for Michigan's most vulnerable populations, low-income and senior customers, and waived late fees for eligible low-income customers receiving energy assistance. In addition, the Company waived deposits

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and reconnection fees for low-income customers, seniors, and those experiencing COVID-19 related financial hardship and seeking restoration of electric service. DTE Electric extended access to and provided greater flexibility of payment plans to customers financially impacted by COVID-19 as well as provided customer assistance personnel with the resources necessary to connect customers to available financial assistance and social service agencies. The customer service programs that were devised and implemented in response to the pandemic are discussed in Company Witness Ms. Johnson's testimony. The Company also delayed the filing of this general rate case to prevent base rate increases, which I discuss later in my testimony.

The Company also took action to keep its employees safe for their own sake, their family's sake, and for the 2.2 million customers that relay upon our product. The continued safe and reliable operation of our generation facilities and distribution grid depends on the health and safety of our employees. The Company initiated new personal protective equipment (PPE) requirements; sequestered select employees to ensure their availability for the safe and reliable operation of our systems; and increased health screening and safety operations to screen employees and contractors. Throughout the pandemic, DTE Electric has remained committed to keeping employees safe and employed.

Q18. Generally, what impact has the COVID-19 pandemic had on the Company in terms of electricity sales?

A18. Electricity sales changed considerably due to the COVID-19 pandemic and since the Company filed its last rate case in 2019. In this instant case, the Company shows an overall improving sales trend from its historical year of 2020 to the projected test period which ends in October 2023. Of course, 2020 was very turbulent due to the start of the COVID-19 pandemic. Though the overall electricity sales trajectory has been an improving one, it remains difficult to project how the COVID pandemic will impact the projected test year in this case. The lingering economic uncertainties impact our sales forecasts. As discussed in Company Witness Mr. Leuker's testimony, since March 2020, mitigation strategies to reduce the spread of COVID-19, including many individuals working at home, have caused a shift in electricity consumption throughout DTE Electric's service territory. In general, these mitigation strategies had an inverse effect on Residential and C&I sales (that is, residential sales higher with declines in commercial and industrial sales). The potential ongoing impacts of COVID-19 are factored into Witness Leuker's forecast as are the needed adjustments to the Company's forecasting methods.

Requested Relief

Q19. What rate relief was approved in the Commission's Order in the Company's last rate case, Case No. U-20561?

A19. The Company's last general rate case, Case No. U-20561, was filed in July 2019 requesting $351 million in rate relief. In the Commission's May 8, 2020 Order, DTE Electric received approval for $188 million in rate relief.

Q20. What actions has DTE Electric taken to delay this request for additional rate relief?

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A20. The Company is aware of the impact that utility rate changes have on our customers, especially considering the COVID-19 pandemic. In consideration for the impacts to customer affordability during these unprecedented times, the Company made three separate accounting requests[1] from June 2020 through February 2021 that would assist the Company and its customers in managing costs. These requests were approved by the Commission and have allowed the Company to continue its investment in infrastructure and maintenance programs while delaying the filing of an application for new base rates. Specifically, the application was delayed from July 2020 until the filing of this instant case which is nearly two and a half years since the Company's last general rate case filing in July 2019.

Q21. What rate relief is DTE Electric requesting in this case?

A21. As Company Witness Mr. Vangilder summarizes, DTE Electric expects a revenue shortfall of $388.2 million for the November 1, 2022 through October 31, 2023 projected test year. The key factors contributing to this shortfall are the revenue requirement associated with increased investments made in plant and the associated depreciation and property tax increases. O&M expenses have increased only moderately from the historical test period, primarily as a result of the inflation projected at the time of this filing.

Q22. Can you highlight some of the major investments and expenses included in the Company's request for rate relief?

[1] Case No. U-20835 filed on June 9, 2020 and approved on July 9, 2020; Case No. U-20921 filed on October 26, 2020 and approved on December 9, 2020; and Case No U-20835 filed on February 26, 2021 and approved on April 8, 2021

A22. This rate case sets forth the rationale, spending, timing, and expected customer benefits associated with significant investments in distribution, generation, and customer service. Several programs to highlight are summarized below.

- Strategic infrastructure investments in substations, poles, wires, transformers and other electric distribution assets to modernize equipment, support growth in customer demand in specific areas, improve worker and public safety, and reduce the frequency and duration of power outages. This includes the 4.8 kV hardening, pole top maintenance program, and increased investment in distribution automation and telecommunications technologies.
- Continuation of the multi-year tree trimming "surge" program that reduces outages on circuits trimmed to the new, more protective standard during the first year after being trimmed. The continuation of the Commission-approved tree trimming program through the test year, combined with the recent $70 million contribution[2] by DTE Electric (an amount that is not included in this rate case), may provide the Company with an opportunity to accelerate the program's completion. This program remains critical to improving reliability and resilience across the system and will be foundational to the Company's overall efforts to improve reliability.
- Construction of the Blue Water Energy Center, a highly efficient combined cycle natural gas plant that will ensure grid reliability and resource adequacy with the closure of three coal plants – Trenton Channel, River Rouge, and St. Clair. This is an important component of the Company's journey to net zero carbon emissions. The Company was granted a certificate of necessity

[2] U-21128 filed August 31, 2021 with Commission order November 4, 2021.

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for this plant on April 27, 2019 in Case No. U-18419 and expects to place the plant into commercial operation by June 2022.

Q23. What investments is the Company making to promote greater levels of advanced technology across its businesses?

A23. The Company believes a diverse set of energy storage applications will be needed to support the reliability and resilience of a decarbonized electric grid. The Company proposes several energy storage pilot programs to test different use cases and applications in this rate case. As the Company transforms its generation and distribution systems, it is essential for the Company to gain first-hand experience with different energy storage applications to shape its long-term operations.

In this case, DTE Electric presents several pilots that will allow the Company to learn more about energy storage use within our generation fleet, distribution system and in conjunction with customer sited batteries. Among these pilots are investments in different technology applications, including 1) green hydrogen storage at the new Blue Water Energy Center; 2) grid-scale battery applications to replace retiring peaking generation; 3) storage for addressing certain substation overloads; 4) residential sited batteries that can be used for back-up power; and 5) customer sited batteries to reduce peak demand. Company Witnesses Mr. Morren, Ms. Pfeuffer, Mr. Burns, and Mr. Farrell support these pilots in their testimonies. Piloting these technologies and use cases under the energy technologies and programs pilot framework, set forth by the Commission Order in Case No. U-20645 on February 4, 2021 order, will provide important learnings and position the

Company to better manage future deployment of battery and other storage applications on DTE Electric's distribution system.

Q24. Are there other projects included in the case that provide examples of the Company's commitment to improving its use of technology?

A24. Other examples of the Company's commitment to improving its use of technology are briefly described below:

- Completion of the new system operations center and installation of additional distribution system monitoring and controls to modernize system operations, will continue to improve the speed and effectiveness of storm responses as well as enable the integration of new technologies such as electric vehicles and distributed solar generation.
- With the success and momentum of the current Charging Forward and eFleet pilots, the Company is proposing the extension of pilot elements and the introduction of new elements. Establishing various pilots, incentives, and ownership models now will allow DTE to develop full-scale programs later that enable widespread EV adoption at a reasonable cost to customers.
- As outlined in the Company's information technology (IT) plans, the customer IT portfolio of investments prioritizes the enhancement of customer experiences across the move-in/move-out**,** billing, payment, collection and outage journeys. The plans also outline how significantly higher level of IT investments are being made to not only support the sustainment of the IT organization and update the current core systems that are critical to operations, but also to advance and enhance new business capabilities.

Rate Case Methodology

Q25. What approach is the Company using to support its projected test year positions and its recommendations in this case?

A25. DTE Electric has used actual historical data as the point of departure for most estimated cost levels for the projected test year. These historical costs were then adjusted for the impact of inflation. As has been DTE Electric's practice in prior cases, certain other costs reflect specific estimates or projections where general impacts of inflation alone would not be appropriate. For example, some of these include, but are not limited to, capital expenditures for new plant, uncollectible expense, and storm expense. All these cost components and the circumstances involved are explained and supported by other Company witnesses.

Q26. What historical and projected test year periods are being used by DTE Electric for purposes of calculating its projected revenue deficiency?

A26. The historical test year used by DTE Electric is the calendar year ended December 31, 2020. This 12-month period was then normalized and adjusted for known and measurable changes, as supported by the Company's witnesses in this case, to arrive at the Company's November 1, 2022 through October 31, 2023 projected test year.

Tree Trimming Surge

Q27. What has the Commission previously approved for tree trim funding in the Company's recent rate cases?

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A27. In the Company's two most recent general electric rate cases (Case No. U-20162 and Case No. U-20561), the Commission approved the deferral of "surge" amounts for the Company's tree trimming program. These "surge" amounts represent an increase in annual funding above the baseline tree trimming O&M and will help the Company achieve a five-year trim cycle for its distribution system. On May 2, 2019 in U-20162, the Commission approved the deferral of "surge" amounts of $43.3 million for 2019, $74.1 million for 2020, and $70.5 million for 2021. In the Company's most recent general rate case, U-20561, the Commission approved $58.2 million of "surge" funding for 2022. As discussed in detail by Company Witness Ms. Hartwick, this "surge" in tree trimming spending will occur over an approximately seven-year period. At the program's termination, the Company expects to maintain a steady-state five-year cycle of tree trimming on its distribution circuits.

Q28. Has the Company made any additional requests of the Commission related to tree trimming since the last rate case (Case No. U-20561)?

A28. Yes. The Company filed an application with the Commission on August 31, 2021 in Case No. U-21128 requesting ex-parte approval to defer a minimum of $70 million collected in 2021 associated with unexpected electricity usage patterns caused by the pandemic. The Company's request sought approval to invest the funds in additional tree trim efforts without seeking future cost recovery. The increased spending would occur through 2023 and any amounts not spent by that time will be refunded to customers. After seeking comments from interested stakeholders, the Commission approved the application on November 4, 2021.

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Q29. Does the approval of the Company's application in U-21128 to defer a minimum of $70 million allow the Company to complete the surge sooner than initially projected?

A29. In the initial program design, the surge was designed to end in 2025 and to place the Company on a five-year trim cycle starting in 2026. The Company is now targeting completion of the surge in 2024 if the resources necessary to perform the program work are available. Details are included in Witness Hartwick's testimony.

Q30. Does approval of the Company's $70 million regulatory liability in Case No. U-21128 impact the revenue requirement being requested in this case?

A30. No, it does not. However, if the Company is successful in its increased tree trimming efforts, it may reduce the deferred surge amounts required in the period beyond the projected test year, though this will be influenced by the ability to attract tree trimming resources at a cost level consistent with the company's past estimates; based on high demand for tree trimmers, especially in California, the costs of these resources may be higher than prior forecasts.

Q31. Are you requesting that the Commission approve additional years of Tree Trim Surge deferrals in this case?

A31. Yes. As stated above, the Commission approved tree trim surge funding through 2022. To continue the Tree Trim Surge program, the Company is requesting that the Commission approve a surge funding deferral of $67 million for calendar year 2023 and $52.7 million for calendar year 2024. This would allow the Company to continue planning work, secure tree trimming contractors and grow the local workforce. The approval helps provide contractors a greater level of work certainty

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and continuity which in turn assists the Company in acquiring and retaining the necessary resources to prevent interruption of the Tree Trim program. Witness Hartwick supports the request in her testimony.

Q32. What other parameters did the Commission specify related to the deferral of the tree trimming surge amounts in previous orders?

A32. In the Case U-20162 May 2, 2019 Order, the Commission specified that the return earned on the Tree Trim Surge regulatory asset for the 2019, 2020, and 2021 deferrals would accrue at the short-term debt rate of 3.56% authorized by the Commission in its order. Lastly, the Commission stated that the Company may seek recovery of the regulatory asset in a future rate case or through securitization.

Q33. In Case Nos. U-20162 and U-20561, the Company discussed its plans to seek securitization of the regulatory asset once it reached approximately $100 million. Has the Company sought the securitization of any of the deferred tree trimming assets yet?

A33. Yes. In Case No. U-21015, the Company requested securitization of $116.2 million of its tree trim deferred asset balance through June 30, 2021. The requested amount represented the total qualified assets of $156.9 million ($43.3 million in 2019, $74.1 million in 2020, and $38.3 million through June 30, 2021, plus interest of $1.2 million) net of deferred federal income tax charges (DFIT) of $43.3 million. The Commission approved the securitization of and recovery up to the total qualified costs of $156.9 million inclusive of DFIT. Additionally, the Commission required the proceeds from the securitization be used to retire both permanent debt and equity for the tree trim surge regulatory asset. Company Witness Ms. Uzenski explains the elimination of the securitized Tree Trim Surge regulatory asset and the related capitalization.

Q34. How has the Company treated the tree trim surge regulatory asset in this general rate case filing?

A34. Though the Company previously, as ordered by the Commission, has included a return on the Tree Trim Surge regulatory asset at the short-term cost of debt approved by the Commission in the Company's 2019 rate case (Case No. 20162), the Company is requesting a change in the "return on" rate it applies to the tree trim surge regulatory asset balance going forward. As I mentioned above, the Commission's Order in the U-21015 securitization filing required the proceeds from the securitization be used to retire both permanent debt and equity for the Tree Trim Surge regulatory asset. Consistent with that determination, the Company should be allowed to recover its actual financing cost in a commensurate manner. Witness Lepczyk supports the use of permanent debt and equity to calculate the return on the Tree Trim Surge regulatory asset. The Company has never amortized any of the tree trim deferred asset balance and is not proposing to do so in this case. The revenue requirement for the deferred amount is calculated by Company Witness Vangilder on Exhibit A-11, Schedule A1.1 using permanent capital supported in this case by Witness Lepczyk.

Q35. When does the Company anticipate making its next securitization filing?

A35. The Company previously anticipated securitizing surge expenses in tranches of approximately $100 million. However, similar to the recent securitization filing in U-21128, the Company will likely file for securitization authorization once the balance reaches approximately $150 million. The upfront cost associated with securitization bonds is largely fixed. As such, the larger tree trimming deferred asset balance allows the Company to lower the overall cost of securitization by potentially reducing the number of bond offerings. The Company has determined that waiting until a larger deferred balance accumulates before securitizing more efficiently spreads the fixed costs and reduces overall securitization costs to customers.

Q36. When does the Company anticipate reaching $150 million of surge expenses?

A36. The Company anticipates that surge expenses will again reach $150 million in late 2023 and anticipates seeking securitization at that time.

<u>R10 production cost allocation methodology</u>

Q37. Is the Company proposing any changes to Rider 10 in this proceeding?

A37. Yes. The Rider 10 pricing structure is unique in that these customers have an interruptible service for which the Company's R10 class is designated as a capacity resource within the MISO Resource Adequacy Construct (unlike non-interruptible customers) and have a significant portion of their power supply rate based on the real time MISO locational hourly marginal energy price. Therefore, it is reasonable that the Rider 10 class cost responsibility for power supply should be different than other customer classes. I have instructed Company Witness Ms. Asghar to provide a 50% credit to the Rider 10 class contribution to Allocation Schedule 100 (Power Plant Energy Production). This credit will reduce the R10 class power supply cost responsibility and thereby reduce the R10 Administrative Charge calculated by Company Witness Mr. Willis.

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Corporate Memberships

Q38. How does the Company determine which corporate memberships to acquire?

A38. The Company acquires and maintains corporate memberships that help in our mission to provide safe, affordable, and reliable energy. Decisions regarding which memberships to obtain are typically made by individual business units. A list of the corporate memberships included in DTE Electric's O&M expense are shown on Exhibit A-27, Schedule Q1. As shown in this Exhibit, each membership generally falls under the auspices of one business unit.

Q39. Do any of the membership costs associated with organizations listed on Exhibit A-27, Schedule Q1 involve lobbying activities?

A39. No. Any memberships, or portions of memberships, related to lobbying activities are excluded from DTE Electric's revenue requirement. Witness Uzenski supports how certain memberships and certain membership costs have been excluded.

Q40. What benefits does the Company receive from DTE Electric's memberships in the organizations listed on Exhibit A-27, Schedule Q1?

A40. The benefits the Company receives from the memberships listed in Exhibit A-27, Schedule Q1 pages 3 through 5 generally fit into one or more of the following broad categories:

- **Benchmarking** - helps the Company understand how its performance and practices compare to its peers,
- **Best practices** - provides insights into industry best practices and potential opportunities for implementation based on those insights.,

- **Research** - performs research that the Company would otherwise have to perform on its own, and leads to access to information at a lower cost than if each member organization performed the research on their own
- **Networking –** helps build relationships with peers that improves the flow of communication between people and companies leading to a greater awareness of industry trends, emerging technologies, emerging issues, and resources

As mentioned above, some of the memberships are a nondiscretionary cost of doing business. These are also noted in Exhibit A-27, Schedule Q1 on pages 1 and 2.

Customer Outage Credits

Q41. Has the Company changed how it treats customer outage credits for ratemaking purposes in this case?

A41. Yes. In prior rate cases, the Company included the payment of outage credits as an O&M expense. The amounts included for recovery represented the customer outage credits paid in the historical test year adjusted for inflation. In this general rate case, I have instructed Witness Uzenski to remove any payments for customer outage credits.

Q42. What rules are the Company's current practices for customer outage bill credits based on?

A42. The Company's practices are consistent with the rules 460.744–747 established by the Commission in the Service Quality and Reliability Standards.

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Q43. Have any changes to these rules been contemplated by the Commission?

A43. Starting in late 2019, the Commission Staff began holding collaborative meetings with electric utilities, industry experts, and other stakeholders to solicit input on updating the utility standards for safe and reliable electric service in Michigan. The Company participated in these collaborative meetings and offered its insights throughout the process while also learning from the expertise of other participants. Currently, the Commission's proposed changes to the Service Quality and Reliability Standards informed by this collaborative effort are in the final stages of approval.

Q44. Why has the Company excluded customer outage credit expenses from this rate request?

A44. The expense amounts the Company has collected in the past for customer outage credits reflected practices that have been in place for many years. Part of those practices involved paying customer outage credits only when an impacted customer requested payment. During collaborative discussions, it became obvious that past practices would change based on the feedback from MPSC Staff. One of those changes, as reflected in the current draft of the service quality and reliability standards, is that electric utilities will be required to provide the credit automatically to the customer.

In anticipation of that change, the Company is preparing for the automatic payment of the customer outage credits and is also using this change in the Commission rules to propose a different treatment for recovery of those credits. Once the rules are final, the Company will be prepared to provide the credits automatically under the new criteria established.

Q45. What is the Company proposing for recovery of customer outage credits going forward?

A45. The Company is proposing to defer for subsequent recovery, the costs of the customer outage credits that it pays starting with the final order in this case. With the Commission's approval, the Company will defer the costs only for those customer outage credits due to outages shown not to be the company's responsibility. Examples of outages outside the companies control are trees falling from outside of the right of way; public interference, such as a vehicle damaging a pole and causing a service interruption; damage caused by animals, or outages caused by the transmission system operator. Those deferred amounts would be reviewed for reasonableness and prudency in the subsequent general electric rate case. Only after the deferred amounts are approved would the Company begin amortizing and recovering them. Witness Uzenski describes the deferral mechanism including the amortization period in her testimony.

Q46. Is the Company making any supporting proposals related to customer outage credits?

A46. Yes. Those outages caused by a customer's failure to keep the service line and the customer's service entrance cable to the meter box free of hazards, including vegetation, will be considered as beyond the Company's control. As a result, any outage credits paid for these types of underlying reasons will be deferred for potential recovery by the Company. I have instructed Witness Willis to make

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changes to the Company's tariff related to customer responsibility, C5.3A. The change is intended to provide increased clarity regarding the customer's responsibility for ensuring their service line and service entrance cable are clear of interference.

Introduction of Other Witnesses

Q47. How will the Company present evidence in support of its requested relief in this case?

A47. The Company will present its case through 31 witnesses, including myself, as described below (in alphabetical order).

1) Ms. Maheen Asghar, Principal Financial Analyst – Load Research and Pricing, supports and justifies the November 2022/October 2023 forecast allocation schedules and the methodology DTE Electric used to include the demand associated with the electric choice loads in forecast distribution allocation schedules.

2) Mr. Robert A. Bellini, Manager – Community Lighting, supports the energy forecast for outdoor lighting; the development of the proposed rate design for the outdoor lighting rate schedules (municipal lighting and other) as well as supports the reasonableness of the historic and projected Community Lighting O&M and the Community Lighting capital expenditures.

3) Mr. Shawn D. Burgdorf, Manager of the Power Supply Strategy & Modeling – Generation Optimization, establishes the projected wholesale market energy sales revenue net of fuel including the reconciliation of 2020. He also provides

an overview of 1) the MISO resource adequacy requirements and capacity market, 2) the capacity import limitation (CIL) enforced by MISO in the Planning Resource Auction (PRA) and its impact on Zone 7, which includes DTE Electric's service territory, 3) the MISO Zone 7 capacity position for Planning Year 2020/2021 and 2021/2022 as well as forecasted capacity positions for Planning Years 2025/26 and 4) the Commission ordered Net Present Value Revenue Requirement (NPVRR) or economic evaluation analysis completed on the Belle River Power Plant.

4) Mr. Benjamin J. H. Burns, Director - Electric Regulated Marketing, provides an update on DTE Electric's approved electric vehicle (EV) program cost projections, introduces a Residential Batteries pilot and the associated costs, explains certain expenditures related to the Advanced Customer Pricing Pilot ("ACPP") regulatory asset, explains the 2023 full Time-of-Use ("TOU") roll out outreach and associated costs, as well as provides support for the Electric Regulated Marketing O&M expense and merchant fee expense.

5) Mr. Michael S. Cooper, Director - Compensation, Benefits & Wellness, presents an overview of benefit expense for DTE Electric for the 2020 historical test period and the November 1, 2022 through October 31, 2023 projected test period. He supports the Company's pension costs, other post-employment benefits (OPEB) costs, active employee health care and other employee benefits costs; discusses potential future COVID-19 related expense; provides an overview of the Company's compensation philosophy for non-represented employees and the role that the Company's incentive plans play in the overall

reasonableness of its total compensation; provides an analysis of the reasonableness of the current total compensation levels; describes the components of the Company's short and long-term incentive plans and supports the inclusion of such costs in the Company's revenue requirement, exclusive of the costs related to DTE Energy's top five executives. In addition, Witness Cooper demonstrates that the quantifiable customer benefits of the Company's incentive plans exceed the expense, as required by the Commission's traditionally mandated cost/benefit analysis of incentive compensation expense.

6) Mr. Jeffery C. Davis, Manager – Nuclear Strategy and Business Support, supports the Company's actual nuclear O&M and capital expenditures for the 12-month historical test period ended December 31, 2020. He also discusses and supports the reasonableness of the projected nuclear O&M and capital expenditures for the interim forecast period and the 12-month projected test period ending October 31, 2023. In addition, he supports the reasonableness of the projected Nuclear Surcharge for the projected test period ending October 31, 2023.

7) Ms. Morgan Elliot-Andahazy, Director - Advanced Distribution Management Systems, describes the Company's approach to implement an Advanced Distribution Management System (ADMS) to improve DTE Electric's ability to monitor and control its electric distribution grid. In addition, she addresses the capital expenditures and justification for the new Electric System Operations Center (ESOC) and the Alternate System Operations Center (ASOC).

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8) Mr. Keegan Farrell, Manager - Demand Response (DR), discusses the development of DR efforts that DTE Electric is conducting and provides support for the expenditures and activities associated with the continuation of existing programs and pilots, as well as the Company's proposals for new pilots. In addition, he discusses proposed changes to DR tariff language and customer penalty revenues from underperformance during DR events.

9) Mr. Neal T. Foley, Director - Regulatory Affairs, discusses the Company's overall approach to rate design and the key components of new tariffs and tariff changes that the Company is proposing.

10) Ms. Shannen M. Hartwick, Director - Tree Trim, discusses the Company's tree trimming program including the 2020 historic period expense as well as the expense for the projected test year. She also supports funding for a tree trim surge program that will enable the Company to deliver the reliability goals established in its Five-Year Plan.

11) Ms. Tamara D. Johnson, Director – Revenue Management & Protection, supports the details of the Company's Low-Income programs and provides explanation and support for the uncollectible expense including a discussion of the impacts on that expense as a result of the COVID-19 pandemic. She proposes changes to the DTE Electric Company Rate Book. She also discusses details of our Low-Income Assistance credits and their impact with the Low-Income Self Sufficiency Program.

12) Mr. Thomas W. Lacey, Principal Financial Analyst – Revenue Requirements Department, supports the revenue requirements by plant/unit study (Plant Study) filed in compliance with the Commission's May 8, 2020 Order in DTE Electric's last general rate case (Case No. U-20561).

13) Mr. Robert J. Lee, Manager - Environmental Strategy, describes the status of two significant Environmental Protection Agency (EPA) regulations, the Steam Electric Effluent Limitation Guidelines (ELG) Rule and the Coal Combustion Residuals (CCR) Rule.

14) Mr. Timothy J. Lepczyk, Assistant Treasurer and Director – Corporate Finance, supports DTE Electric's projected capital structure and the cost of its long and short-term debt to be used in the determination of DTE Electric's overall rate of return in this proceeding.

15) Mr. Markus B. Leuker, Manager – Corporate Energy Forecasting, provides the Company's current electric sales, maximum demand, and system output forecast for the period 2021-2026, including the projected 12-month test period November 2022 through October 2023. He discusses the outlook for the national and local economy which is the basis of the forecast. Witness Leuker also describes how the forecast of electric sales, maximum demand and system output is developed and supports the reasonableness of the electric sales forecast used by DTE Electric in this proceeding.

16) Mr. Habeeb J. Maroun, Principal Financial Analyst – Revenue Requirements Department, presents Unbundled Cost of Service (UCOS) Studies for DTE

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Electric's projected test year ending October 31, 2023. He also supports revenue requirement calculations for: (1) customer related costs, and (2) capacity charges by rate class.

17) Mr. David C. Milo, Fuel Resource Specialist – Fuel Supply, supports DTE Electric Fuel Supply's and Midwest Energy Resources Company's operations and maintenance expense and capital expenditures for the twelve months ended December 2020 historical actual, and as projected for 2021 through October 31, 2023.

18) Mr. Justin L. Morren, Plant Director - Fossil Generation, explains the status of DTE Electric's Fossil Generation power plants and ratings; provides a review of the Fossil Generation base coal unit availability performance for five years prior and five years following the test year in this case; supports the historical 2020 level of capital expenditures on a plant level basis and the forecast of capital expenditures planned for 2021 through October 31, 2023; Witness Morren also supports the known and measurable changes in Fossil Generation O&M expenses that will span the timeframe from the 2020 historic test year in this case to the projected test year, ending October 31, 2023. In support of the Company's advancement in the decarbonization arena, Witness Morren provides details on projects that will introduce two emerging technologies — hydrogen-fueled generation and grid scale Battery Energy Storage Systems (BESS) — into the Company's generation portfolio.

19) Mr. Thac K. Nguyen, Manager – Energy Waste Reduction, discusses the development, future plans, and related expenditures associated with the DTE Insight Program.

20) Ms. Sharon G. Pfeuffer, Vice President – Distribution Operation Engineering and Construction, supports the historical capital expenditures and O&M expenses related to electric distribution activities for 2020 and the projected capital expenditures and O&M expenses for 2021 to October 31, 2023, and the capital and O&M forecasts for the projected test period of November 1, 2022 to October 31, 2023.

21) Ms. Angie M. Pizzuti, Vice President and Chief Customer Officer, discusses the Company's efforts to create "Distinctive Service Excellence" and transform the customer experience through targeted investments in the Customer IT Portfolio, which includes all Information Technology projects that support, enable, or directly impact customer operations, customer interactions, and the customer experience.

22) Mr. Joseph E. Robinson, Director of Engineering and Planning - Electric Distribution Operations, supports (1) the Company's approach, analysis and results regarding the line loss study that was directed to be accomplished in the Order for Case No. U-20561, (2) clarification of the rules and regulations language in Section C of the Company's Rate Book for Electric Service regarding service connections, (3) the Company's existing Contribution in Aid of Construction policy, and (4) the Company's grid data analytics plan and future grid integration studies requested in Senate Resolution 143.

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23) Mr. Pankaj Sharma, Director – Information Protection & Security within the Information Technology Services (ITS) organization, discusses IT capital investment categorization within the Company; describes the capital investment planning process that drives prioritization of both single and multi-year projects and programs; supports the Company's IT capital expenditures beginning with the historic test year and extending through the projected test year; and describes the variances in the actual 2019 and 2020 expenditures from the projected 2019 and 2020 expenditures in the Company's previous general rate case.

24) Mr. Phillip L. Smith, Director – Operational Technology for Distribution Operations, supports capital related to the Advanced Metering Infrastructure project for the 2020 historical test period, as well as the projected capital expenditures for 2021 to 2023, leading to the capital forecasts for the projected test period of November 1, 2022 to October 31, 2023.

25) Mr. Jason E. Sparks, Director – Customer Service Operations, explains the Company's actual Customer Service O&M expenses for the 12 month period ended December 31, 2020 and provides support for projected O&M expenses for the projected test period ending October 31, 2023.

26) Ms. Theresa Uzenski, Manager – Regulatory Accounting, supports DTE Electric's financial statements for the historical test year ended December 31, 2020, the interim forecast period and a twelve-month projected test period ending October 31, 2023, with certain adjustments necessary for presenting the

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financial information in the appropriate format for ratemaking purposes. She supports the development of the projected test year adjusted electric operating income based on forecasted changes from the normalized historical electric operating income. Ms. Uzenski also supports the Corporate Staff Group expenses for the historical and forecasted periods and explains the function of this group and the method for allocating costs to DTE Electric and the other DTE Energy subsidiaries. She supports that costs recovered from other mechanisms are excluded from the financial statements in this case (including the Transitional Recovery Mechanism for the transition of Detroit Public Lighting Department customers, the Renewable Energy Program, and Energy Waste Reduction). She explains the requested treatment of costs to expand upon the Company's Charging Forward program to include a broader application of electrification to transportation infrastructure; describes the Company's proposed accounting for unused Low- Income Assistance (LIA)/Residential Income Assistance (RIA) credits and explains the accounting for the Company's requests to defer implementation costs related to the Company's Time of Use rate offering, defer pension expense, and defer COVID-19 expenses. She also provides support for revenues collected for coal combustion residual clean-up costs.

27) Mr. Kirk M. Vangilder, Principal Financial Analyst - Revenue Requirements, supports DTE Electric's twelve months ended December 31, 2020 historical revenue deficiency. In addition, he is sponsoring Net Operating Income (NOI) adjustments for interest synchronization and income tax savings, as well as the revenue conversion factor. Mr. Vangilder is sponsoring DTE Electric's twelve

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months ending October 31, 2023 projected revenue deficiency. He also calculates the incremental revenue requirement for DTE Electric's Tree Trim Surge regulatory asset and the net present value of the Tree Trim Surge Program.

28) Dr. Bente Villadsen, Principal at The Brattle Group, supports the cost of capital for the Company. Specifically, Dr. Villadsen provides return on equity (ROE) estimates derived from a sample of comparable risks. Dr. Villadsen also considers the business and financial risk of the Company relative to the proxy companies' ratio to arrive at her recommendation for the allowed ROE of 10.25%.

29) Mr. Aaron Willis, Manager – Regulatory Economics, discusses and supports the Power Supply Costs for the projected test year, the proposed Rate Design, Contribution in Aid of Construction (CIAC), and the Retail Access Service Rider.

30) Ms. Sherri Wisniewski, Director – Tax Operations, supports the DTE Electric Federal Income Tax, Michigan Corporate Income Tax, Municipal Income Tax, property tax and other general taxes for the 2020 calendar year historical period as well as the twelve months projected test period ending October 31, 2023.

Q48. Does this complete your direct testimony?

A48. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MAHEEN ASGHAR

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MAHEEN ASGHAR

Line
No.

Q1. What is your name, business address, and by whom are you employed?

A1. My name Maheen Asghar (she/her/hers). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Services, LLC (DTE Energy) as a Principal Financial Analyst – Regulatory Economics.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Science in Computer Science from Wayne State University and a Master of Science in Information (data science and analytics) from the University of Michigan.

Q4. What is your professional experience?

A4. I began my career at DTE Energy, in 2014, as a co-op programming student in Distribution Operations (DO). I transitioned to a full-time position as an Operations Analyst within DO in 2016, where I worked primarily with outage data. In 2019, I accepted a position in Corporate Strategy, a role in which I supported key operational and strategic work across the Company. I joined Regulatory Affairs in 2021, as a Principal Financial Analyst.

Q5. What is your current position?

A5. Currently, I am a Principal Financial Analyst in Regulatory Affairs. In this position, I am responsible for evaluating customer class usage characteristics, developing allocation schedules for use in cost-of-service studies and rate design, and for measuring and evaluating demand response programs offered by the Company.

Q6. Have you received any additional training?

A6. I attended the AEIC Load Research & Analytics Fundamentals of Customer Load Data Analysis Seminar in 2021.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. I have not previously testified in a case before the MPSC.

Line No.

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to support and justify the November 2022 to October 2023 forecast allocation schedules.

Q9. Are you supporting any exhibits in this case?

A9. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-5	E2	Cost of Service Allocation Methodology Diagram
A-5	E3	Allocation Schedule Description
A-17	G1.1	2022/2023 Forecast Energy Allocation Schedules
A-17	G1.2	Demand and Energy Allocation Percentages by Rate Class

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. What are the sources of data used for the allocation schedules?

A11. The November 2022 to October 2023 forecast allocation schedules are based on 2020 customer class sales data obtained from the 2020 Total System Analysis (TSA). The forecast allocation schedules are based on the energy sales forecast for the residential, commercial and industrial classes supported by Company Witness Leuker, the street lighting and traffic signals sales forecast supported by Company Witness Bellini, and the forecast billing determinants supported by Company

Witness Willis. These sales levels are shown with losses on Exhibit A-17, Schedule G1.1.

Background and Basis for Allocation Schedules

Q12. Are there any technical terms used in your testimony that may require explanation?

A12. Yes. To aid in understanding and to avoid confusion, I am defining the following terms that I use throughout my testimony:

- Customer Class or Class of Service: A set of customers with similar characteristics who have been grouped for the purpose of setting an applicable rate for electric service.
- Total System Analysis (TSA): The study of all customer classes that identifies the hourly demand values for all hours of the year. This is the foundation of allocation schedules.
- Energy: The total kilowatt-hours (kWh) or megawatt-hours (MWh) supplied to or used by an individual customer or customer class.
- Demand: The rate at which electric energy is used at a given instant or averaged over a designated time interval. Typically, demand is expressed in kilowatts (kW) or megawatts (MW).
- Service Area System Peak Demand: The highest hourly demand for all customers (full service and choice) served on the DTE Electric distribution system within a specific period (day, month, year, etc.). Service Area System Peak Demand is commonly referred to as the 'system peak.'

- Bundled Peak Demand: The highest hourly demand for all customers served by DTE Electric's production system within a specific period (day, month, year, etc.). Bundled Peak Demand is commonly referred to as 'bundled peak.'
- Coincident Peak Demand (CP): The demand of any customer class within a specific period (day, month, year, etc.) that occurs at the same time as the system peak or the bundled peak demand for the same period.
- 12CP: The demand value derived by averaging the actual demand values registered on the monthly system or bundled peak hours for January through December for each customer class.
- 4CP: The demand value derived by averaging the actual demand values registered on the monthly bundled peak hours for June through September for each customer class.
- Non-Coincident Peak Demand: The maximum demand of any customer class within a specific period but not necessarily occurring at the time of the system peak demand for that period.
- Losses: A term used to define the difference between the electrical energy delivered to a customer (or a given point on the electrical distribution system) and the amount of electrical energy that must be generated at the power plant to serve that customer. In other words, losses refer to the difference in the amount of power generated from the power plant and the point of delivery.
- Load Factor: The ratio, in percent, of the total energy over a designated period of time to the maximum hourly demand (bundled or system) occurring in that period. Load factor is calculated by the formula:

LF (%) = (Total Energy / (Peak Demand * No. of Hours)) * 100

- Customer-Owned: Industrial customers that use customer owned substations.

- DTE-Owned: Industrial customers that use DTE Electric single customer or joint-use general distribution substations.
- Transmission Voltage Level: Served directly from the transmission system at 120 kV or above, or from the transmission system through a DTE-owned substation dedicated or primarily providing service to the customer and located on or immediately adjacent to the customer's premises.
- Sub-transmission Voltage Level: Served directly from the sub-transmission system at voltages from 24 kV to 41.6 kV or from the sub-transmission system through a DTE-owned substation dedicated or primarily providing service to the customer and located on or immediately adjacent to the customer's premises.
- Primary Voltage Level: Served directly from the primary distribution system at a nominal voltage between 4.8 kV and 13.2 kV who does not qualify as either a transmission voltage customer or a sub-transmission voltage customer.
- Secondary Service: Served directly from the secondary distribution system at a nominal voltage less than or equal to 4.8 kV and who does not qualify as either a transmission voltage customer, sub-transmission voltage customer or a primary voltage customer.

Q13. What is the purpose of the allocation schedules you have developed?

A13. Allocation schedules are developed using customer class sales, data from Advanced Metering Infrastructure (AMI), and quantitative methods to determine the extent (expressed as a percentage) that each customer class uses the various portions of the electrical system. In this case, the customer class usage percentages determined in the allocation schedules are one of the inputs used by Company Witness Maroun to determine customer class cost responsibility. Because all customer classes do not utilize the full distribution system to take delivery of electrical service, the allocation schedules are developed to assign only the portions of the system used by each customer class. Exhibit A-5, Schedule E2, is a diagram which reflects the applicability of allocation schedules to customer class.

Q14. How did you develop the allocation schedules?

A14. There are 11 forecast allocation schedules that I develop for use in cost-of-service studies (see Exhibit A-5, Schedule E3 for a description of each schedule). Each schedule was developed to allocate to each customer class' utilization of a particular part of the electrical system, which is the industry standard practice for developing allocation schedules. Schedule 100, shown in Exhibit A-17, Schedule G1.2, is based on the class's forecasted energy consumption. and the remaining 10 allocation schedules described in Exhibit A-5, Schedule E3, are based on the forecasted demand that a customer class places on the various portions of the electrical system. The allocation schedule numbers and the associated portion of the electrical system they represent are shown schematically on Exhibit A-5, Schedule E2.

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Q15. Why does the measurement basis differ for each allocation schedule?

A15. The measurement basis for each allocation schedule is based on the design and service requirements for each portion of the electrical system. Specifically, forecasted energy is used for Power Plant Energy Production (Schedule 100) required to serve customers. As customers use energy, they create a demand (rate at which energy is used and/or delivered) on the system.

The output capacity of power plant production is designed considering the peak demand requirements of the production system, measured as the bundled peak demand. Production Schedules 200A and 200B are measured based on the forecasted bundled 4CP. Schedule 201 – Distribution is based on the forecasted 12CP of the of the Service Area.

Schedules 202, 203A, 203B, 203C, 204 and 205 refer to substations, high voltage lines and transformers, which are designed to carry the maximum load required by the customer classes they serve regardless of whether the class maximum demand occurs at the same time or a different time as the system peak. The forecasted non-coincident peak demand is the measurement basis for these allocation schedules.

Low voltage secondary lines are designed to serve the absolute maximum demand level of the customers they feed. Therefore, Schedule 300 is based upon the forecasted sum of the individual customer maximum demands.

Forecast Allocation Schedules

Line No.

Q16. How was the 2020 TSA used to develop the demand values determined for the forecast allocation schedules?

A16. The basis for the forecast allocation schedules developed for this case are the forecasted net sales values presented in Witness Leuker's Exhibit A-15, Schedule E1. However, because Witness Leuker's system peak demand forecast does not contain the associated customer class level demand values necessary for allocation schedule development, it was necessary to develop these corresponding demand values by customer class. This was done by applying historical load factors to the forecast energy values using industry standard load research principles to derive demand values using energy and load factor. Therefore, forecast demands were calculated by dividing the net forecast energy values without losses, by the product of the historic load factor and annual hours (8,784 hours per year as 2020 was a leap year).

Q17. How were the appropriate historic load factors determined?

A17. A 5-year average load factor was derived from years 2016-2020 and used for each cost of service class.

Q18. Why is using the 5-year average historical load factor a better representation of the class' performance than the actual 2020 historic load factor?

A18. Using the 5-year average load factor accounts for any abnormalities in any single year and smooths out any variability due to weather, or other anomalies such as economic conditions.

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Q19. Why is using average historical load factors a reasonable method of determining forecast demand values?

A19. This approach is reasonable because it utilizes industry standard load research principles that are defined in the "The Art of Rate Design", published by the Edison Electric Institute (EEI), taught in the EEI Rate Fundamentals Course, and published in Chapter 7 of the Association of Edison Illuminating Companies (AEIC) Load Research Manual, 3rd Edition. These sources define the relationship of load factor to demand and the principle of using energy and load factor to calculate demand.

Q20. How did you develop the November 2022 to October 2023 forecast allocation schedules?

A20. I applied the 5-year average load factors to the forecasted energy sales received from Witness Leuker to produce the November 2022 to October 2023 forecast schedules shown in Exhibit A-17, Schedule G1.1.

Q21. Where any other changes made to the forecast allocation schedules?

A21. Yes. The electric line loss factors were changed in the present case. The Company completed a new electric line loss study based on 2019 data, which examined average line losses by month and by voltage. The line loss study and a detailed description of how it was performed are explained in further detail by Company Witness Robinson.

Q22. How are line losses used in forecast allocation schedules?

A22. Line loss factors are used as a multiplier in allocation schedules to increase the energy or demand value for a given schedule to reflect the amount of production

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needed to serve the customer class. Line losses were measured by voltage level, allowing allocation schedules to accurately reflect demands on the system caused by different classes of customers.

Q23. Are the allocation schedules defined in your testimony developed using established principles and methods?

A23. Yes. I used the industry recognized and accepted load research principles supported by EEI and AEIC. The methods I used are consistent with the methods used by the Company in all its electric general rate cases filed since 2014.

Q24. Does this complete your direct testimony?

A24. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority**.**	**)**	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ROBERT A. BELLINI

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Robert A. Bellini (he/him/his). My business address is 8001 Haggerty, Belleville, Michigan 48111. I am employed by DTE Electric Company (DTE Electric or Company) as Manager of Community Lighting.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background and business experience?

A3. I graduated from Central Michigan University with a Bachelor of Science degree in Business Administration in 1999. In 2005, I graduated from Oakland University, with the degree of Master of Accountancy. From 2005 until 2008, I was employed by Deloitte & Touche LLP as a financial auditor. While employed at Deloitte & Touche, I passed the Certified Public Accountant (C.P.A.) examination and became a licensed C.P.A. in 2007. In 2007, I was promoted to Senior Auditor on client engagements. In this role, I was responsible for tailoring each audit based on a client's industry and the risks inherent in their operations, supervising the audit fieldwork, and communicating the audit issues and results with client management.

In 2008, I joined DTE Energy as a Financial Auditor. My responsibilities included executing both financial and Sarbanes-Oxley (SoX) audits in support of the DTE Energy 10K annual filing under the guidance of our external auditor, PriceWaterhouseCoopers (PWC). In 2010, I was promoted to Senior Auditor. My responsibilities included planning, scoping, and executing both financial and operational audits. In 2013, I was promoted to Principal Supervisor of the Joint

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Use department. My responsibilities included developing budgets, forecasting, and negotiating joint use agreements with various attaching entities. In 2016, I was promoted to Manager, Joint Use. In 2018, I was promoted to Manager, Community Lighting.

Q4. What are your duties and responsibilities as Manager of Community Lighting?

A4. In this capacity, I am responsible for managing the marketing and sales, budgeting and forecasting, planning and construction and asset management for nearly 197,000 DTE Electric-owned street lights and outdoor protective lights. I also manage the maintenance and provision of energy to municipally owned streetlights and the provision of energy-only service to municipalities, in accordance with DTE Electric's MPSC-approved tariffs. DTE Electric's assets related to these services include mercury vapor, metal halide, high pressure sodium, and light-emitting diode (LED) luminaires.

Q5. Have you previously provided testimony before the Michigan Public Service Commission?

A5. Yes, I have. I sponsored testimony in Case No. U-20561, the DTE Electric 2019 General Rate case.

Purpose of Testimony

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to support cost recovery relative to O&M and Capital expenses related to DTE Electric's lighting assets. I will:

- Support the energy forecast for the various outdoor lighting rates including automated traffic signal (ATS) rates and metered street lighting rates;
- Support and discuss the reasonableness of the Company's actual Community Lighting O&M expenses ended December 31, 2020, and the projected Community Lighting O&M expenses for the 12-month projected test period ending October 31, 2023;
- Support and discuss Community Lighting's capital expenditures for the historical test year ended December 31, 2020, and the projected Community Lighting capital expenditures for the 12-month projected test period ending October 31, 2023;
- Support the proposed rate design for the outdoor lighting (municipal and other) and ATS tariff offerings using the lighting model;
- Support and discuss proposed wording changes for certain E1 and D9 Outdoor Lighting tariff sheets;
- Provide a plan to reduce costs to maintain overhead fed lights as well as promote efficiency through the use of technology.

Q7. Are you sponsoring any exhibits?

A7. Yes. I am sponsoring in whole, or in part, the following exhibits:

Exhibit	Schedule	Description
A-12	B5.5	Projected Capital Expenditures – Community Lighting

A-13	C5.6	Projected Operation and Maintenance Expenses – Distribution Expenses
A-16	F3	Present and Proposed Revenues by Rate Schedule – 12 months ending October 31, 2023
A-16	F8	Proposed Tariff Sheets
A-25	O1	Community Lighting Outdoor Lighting Outage Duration
A-25	O2	Community Lighting Outdoor Lighting Outage Cost

I am sponsoring lines 8 and 22 within Exhibit A-13, Schedule C5.6, page 1 of 2, and the pages specific to the residential and commercial outdoor protective lighting (OPL) and municipal classes within Exhibit A-16, Schedule F3. This includes pages 46 through 57. On Exhibit A-16, Schedule F8, I am sponsoring the OPL and municipal tariffs while Company Witness Mr. Willis sponsors the tariffs for the remaining customer classes.

Q8. Were these exhibits prepared by you or under your direction?

A8. Yes, they were.

Q9. Could you describe the portfolio of Community Lighting assets that DTE Electric owns, operates, and maintains on behalf of its customers?

A9. Yes. DTE Electric owns, operates and maintains approximately 197,000 Community Lighting assets which include municipal, commercial, and residential customers. There are approximately 83,000 street lights that are owned by the customer (municipality). Ownership of Community Lighting assets is detailed in Table 1 below:

Table 1 Community Lighting Assets

Asset Type	Asset Ownership	Rate Type	# of Assets	Description
Municipal OH &UG Street Lights	DTE Electric	E1 Option I	164,890	DTE Electric owned and maintained system
Municipal OH &UG Street Lights	Customer	E1 Option II	195	Municipally owned and DTE Electric maintained system
Municipal OH &UG Street Lights	Customer	E1 Option III	82,625	Municipally owned and maintained system
Commercial Outdoor Protective Lights	DTE Electric	D9	23,023	DTE Electric owned and maintained lighting equipment
Residential Outdoor Protective Lights	DTE Electric	D9	9,452	DTE Electric owned and maintained lighting equipment

Q10. Can you provide an overview of DTE Electric's Community Lighting Municipal Street Lighting Business?

A10. Yes. DTE Electric Community Lighting provides MPSC-approved tariff service to approximately 165,000 street lights on its E1 Option I Rate Schedule, approximately 200 municipally-owned street lights on its E1 Option II Rate Schedule, approximately 83,000 municipally-owned street lights on its E1 Option III Rate Schedule, and approximately 32,000 OPLs on its D9 Rate Schedule. In addition to the lighting services above, Community Lighting provides MPSC-approved tariff service to municipalities for the operation of ATS lights on its E2 Rate Schedule.

DTE Electric's E1 Option I Rate Schedule and the proposed pricing reflects recovery of costs associated with its ownership, maintenance and provision of energy to its portfolio of mercury vapor, high pressure sodium, metal halide (collectively referred to as high intensity discharge (HID)) and LED street lighting. DTE Electric's E1 Option II Rate Schedule (closed to new customers since January 2009) is applicable to street lighting systems owned by municipalities, but maintained by the Company. DTE Electric's E1 Option III Rate Schedule is applicable to street lighting systems which are both owned and maintained by the municipality for which the Company provides only the energy.

Q11. Can you provide an overview of the various lighting technologies that DTE Electric's Community Lighting employs in its Municipal Street Lighting Business (Option I)?

A11. Yes. The current lighting portfolio for street lighting customers served on DTE Electric's E1 Option I Rate Schedule includes approximately 51,000 high pressure sodium luminaires and approximately 94,000 LED luminaires, or 31% and 57% of its total Company-owned street lighting portfolio, respectively. While the quantity of high pressure sodium luminaires has been steadily dropping over the past several years, the total number of LED luminaires continues to increase in-kind due to the conversion of HID luminaires.

11%, or approximately 19,000 of DTE Electric's street light assets are currently mercury vapor luminaires. The mercury vapor technology became obsolete pursuant to the Energy Policy Act of 2005, and, as a result of their obsolescence and inefficient use of energy, the quantity of mercury vapor street lights has been reduced by approximately 74,000 over the past ten years, primarily through their conversion to LED luminaires. DTE Electric no longer performs periodic group re-lamping of the mercury vapor lighting; rather, the lamps are replaced upon lamp failure. When the entire mercury vapor lighting unit (consisting of the luminaire, lamp, and photocell) fails, DTE Electric converts the failed unit to LED lighting due to its continuing obligation to provide service for Municipal Street Lighting

(MSL) customers taking service under its E1 Option I Rate Schedule. DTE Electric began to convert failed mercury lighting to LED lighting on February 1, 2017 in accordance with the MPSC's January 31, 2017 Order in MPSC Case No. U-18014. Prior to February 1, 2017, all failed mercury vapor lights were converted to high pressure sodium. Metal halide lighting luminaires represent approximately 1% or approximately 1,500 of DTE Electric's company owned lighting luminaires

Q12. Can you provide an overview of the various lighting technologies for the street lights that are municipality owned (Option II & III)?

A12. Yes. The mix of lighting for DTE Electric's E1 Option II Rate Schedule reflects a mix of 83% high pressure sodium and 17% mercury vapor. As I previously indicated, this service has been closed to new customers since 2009, and existing E1 Option II Rate Schedule customers electing to convert to LED are required to convert to DTE Electric's E1 Option I or Option III Rate Schedules. The mix of lighting for DTE Electric's E1 Option III Rate Schedule includes approximately 69,000 LED luminaires or 84% of the total; approximately 13,000 are high pressure sodium luminaires, or 15% of the total, with the balance being a mix of mercury vapor and metal halide. The high concentration of energy efficient LED lighting reflects the City of Detroit's conversion of most of its street lights to LED.

Q13. Can you provide an overview of DTE Electric's Community Lighting OPL (D9 Rate Schedule) and ATS Business (E2 Rate Schedule)?

A13. Yes. DTE Electric's D9 Rate Schedule and the proposed pricing reflects recovery of costs associated with its ownership, maintenance and provision of energy to its portfolio of approximately 23,000 commercial and more than 9,000 residential outdoor protective lights. DTE Electric's OPLs employ the same lighting technologies as its street lights and, consistent with its conversion of failed mercury vapor street lights to LED lighting, DTE Electric began to convert failed mercury vapor OPLs to LED lighting on February 1, 2017.

DTE Electric's E2 Rate Schedule and proposed pricing reflects the recovery of costs for the production and distribution of energy for ATS lights owned and maintained by municipalities and other public authorities. This service is an energy-only service and represents annual load of more than 59 GWh including service to the City of Detroit.

DTE Electric also provides metered municipality-owned streetlight service under the E1.1 Rate Schedule. Total annual load on this service, including service to the City of Detroit, is approximately 10 GWh. I support the energy forecast for this Rate Schedule and Witness Willis supports the proposed rate for this service.

<u>Community Lighting Sales Forecast</u>

Q14. How did you develop the sales forecast for Lighting?

A14. Consistent with the method used in prior rate cases, the sales forecast for the E1 Option I Rate Schedule was developed by first preparing a forecast of light counts for each lighting type (technology and wattage size) for the projected test period based upon: (1) known projects, (2) continued conversions of mercury vapor lighting to LED lighting, and (3) an estimate of increased light counts net of removals, resulting from sales growth. The system wattage (nominal lamp wattage plus ballast wattage) applicable to each lighting type was applied to the forecasted volume of lights for each lighting type. Annual usage was assumed to be 4,200 hours, to reflect the hours that the lights on either the dusk to dawn or standard provision are illuminated. The energy forecast for lights on the dusk to midnight provision was based upon 2,100 hours use and the energy forecast for lights on the de-energized provision is zero.

The sales forecast for the E1 Option II Rate Schedule was developed based upon the existing light counts for each of the lighting types. The system wattage value applicable to each lighting type was applied to the forecasted volume of lights for each lighting type for the 4,200 hours for which all the lights are illuminated on an annual basis.

The sales forecast for the E1 Option III Rate Schedule was developed by first preparing a forecast of light counts for each of the lighting types for the projected test period based upon known projects and an estimate of light count changes. The system wattage value applicable to each lighting type was applied to the forecasted volume of lights for each lighting type for the 4,200 hours for which all the lights are illuminated on an annual basis.

The total sales forecast for the OPL D9 Rate Schedule, like that prepared for the E1 Rate Schedule, was developed by preparing a forecast of light counts for each of the lighting types for the projected test period based upon existing light counts, an estimate of increased light counts resulting from sales growth net of removals, and continued conversion of mercury vapor lighting to LED lighting. The system wattage value applicable to each lighting type was applied to the forecasted volume of lights for each lighting type for the 4,200 hours for which the lights are illuminated on an annual basis.

The total sales forecast for the ATS E2 Rate Schedule was determined by using the total connected wattage, as of March 1, 2021, for that rate schedule and determining the annual usage based upon that determinant. In other words, it is simply the product of the total reported wattage and the total number of hours in the projected test period.

The total sales forecast for the E1.1 Rate Schedule was based upon annualized usage data for the 12-month period that ended December 2020.

Community Lighting Operations

Q15. What is included in the Maintenance of Street Lighting and Signal Systems account on lines 8 and 22 of Exhibit A-13, Schedule C5.6?

A15. Lines 8 and 22 on this exhibit show the Projected Operation and Maintenance Expenses that are directly assigned to Operation and Maintenance of Street Lighting and Signal Systems. The total historical period expense of $3.8 million in Account 596 (Maintenance of street lighting and signal systems) represents preventive maintenance expense, labor expense and non-capitalized outage restoration expense. The preventive maintenance work included post inspection, post painting, re-lamping of metal halide luminaires, and night patrols for DTE owned municipal streetlights. The labor expense primarily reflects the labor of the Community Lighting team including sales, planning, asset maintenance, construction and asset engineering. As reflected on Exhibit A-13, Schedule C5.6, the historical period operation and maintenance (O&M) expense of $3.8 million is adjusted for inflation of 3.1% for 2021, 2.9% for 2022, and 2.42% for the first 10 months of 2023.

Q16. How often does DTE Electric inspect posts?

A16. DTE Electric has more than 60,000 posts, and has established detailed post inspection criteria to inspect its posts every three years to both identify posts whose structural integrity dictates their replacement (condemnation), and posts that require painting. At the time posts are inspected, minor post maintenance work such as adding or replacing post asset tags, post hand-hole covers, and T-box door covers may also be completed. Over the past nine years, DTE Electric's post inspection process has resulted in the annual replacement of condemned posts at a rate of approximately 3.5% and post painting at a rate of approximately 8.9% relative to the total population of posts. These inspection service results are mutually exclusive meaning that posts which get replaced are not included in the tally of those posts which get identified for painting.

Q17. Does your historical O&M expense include any preventive maintenance expense for LED luminaires?

A17. Yes. Prior to 2018, DTE Electric had not performed any preventive maintenance on LED luminaires. However, beginning in 2018, DTE implemented LED washing as part of its preventive maintenance program.

Q18. Why has DTE Electric initiated a LED washing and group relamping preventive maintenance program?

A18. DTE Electric currently re-lamps its HID luminaires on a periodic basis to ensure that their performance (light output) is maintained at an appropriate level to provide for the safety and security of its customers. Given the increasing saturation of LED luminaires in its lighting portfolio, DTE Electric was similarly concerned about the lighting performance of LED luminaires over time. Because of this concern, DTE Electric conducted two formal and separate LED light loss factor (LLF) studies, initially in 2015 and again in 2017, to determine how LED lumen output depreciated over time. The results of those studies identified the need to wash LEDs on a periodic basis to ensure that their lumen output remained at or above L70 (70% of the original design lumen output), the level at which the Lighting Industry has defined LED luminaire end of life and no longer provides acceptable light output to meet the lighting safety and security design requirements of its customers.

Q19. How has DTE Electric determined the projected expense for the performance of the LED luminaire washing and group relamping?

A19. Based upon the results of the LLF studies, DTE Electric developed an LED luminaire 5-year washing schedule for its LED luminaire portfolio from the time when the LED luminaires were originally installed. For instance, LED luminaires originally installed in 2016 will generally be washed in 2021, LED luminaires installed in 2017 will generally be washed in 2022, and so on. HID luminaires are also targeted to be relamped on a 9 year cycle similar to that described for LED luminaires.

DTE washed approximately 7,300 LED luminaires and relamped approximately 11,000 HID luminaires in 2020, and is currently on pace to wash approximately 7,300 LED luminaires and relamp approximately 5,300 HID luminaires. For both programs, DTE was able to obtain firm unit pricing from our contractors who are tasked with performing this work.

Q20. Do you consider the actual and projected expenses for Community Lighting shown in Exhibit A-13, Schedule C5.6 reasonable?

A20. Yes, I do. I base this on my analysis of past expenses, projected requirements for labor and material for the safe and reliable distribution of electric power, and plans for maintaining and/or improving customer service.

Q21. What are the Community Lighting capital expenditures on Exhibit A-12, Schedule B5.5, "Projected Capital Expenditures – Community Lighting"?

A21. Capital expenditures for Community Lighting for 2020 were $15.2 million. The 2020 expenditures included approximately $4.7 million for outage restoration, approximately $.8 million for post replacement, and the balance for new business, planned HID to LED conversions, and capital support staff.

The projected capital expenditures for Community Lighting are $15.7 million for 2021, $13.9 million for 10 months ending October 31, 2022, and $16.7million for 12 months ending October 31, 2023. Similar to the 2020 actual expenditures, these projections include outage restoration, including conversion of failed mercury vapor luminaires to LED for both street light and OPLs, post replacement, planned

HID to LED conversions, new business, and capital support staff. Other work will include targeted infrastructure upgrades such as underground cable replacement.

Q22. What is the Community Lighting team's performance with respect to outage restoration activity?

A22. In 2020, DTE Electric's Community Lighting team spent approximately $6.3 million on outage restoration expense with approximately 75% of this cost being capitalized, and the balance being recorded as O&M. The outage restoration expense was approximately $8 million in 2019, with the reduction in year-over-year outage expenditures caused by the reduced availability of contract crews resulting from the impact of Covid-19. DTE Electric places a significant amount of focus on its outage restoration process and employs balanced metrics to ensure that its outage restoration costs and outage duration are optimized. Exhibit A-25, Schedule O2 reflects DTE Electric's historical performance for outage restoration cost per event.

Q23. What was DTE Electric's performance with respect to outage duration for its lighting customers?

A23. DTE Electric has several targets for outage performance: outage duration and outage defects. DTE Electric's 2020 outage duration target was 3.1 business days and DTE Electric's 2020 actual performance was 3.3 business days. These historical metrics are displayed on Exhibit A-25, Schedule O1. The historical metrics for outage defects over the past ten years are also displayed on Exhibit A-25, Schedule O1.

In addition to weather-related events, "long duration" and "follow-up" outage events include extended repair time for underground faults (i.e. Miss Dig permits), repairs resulting from third party damage, and lack of special order material (SOM) maintained by a city or municipality. The performance metrics only include reactive street light outage repairs; they do not include any outage repair resulting from patrol and fix activities nor any preventative maintenance activities such as group re-lamping. DTE Electric's outage work management system for street lighting uses 24-hour military time protocol and measures duration to the minute degree. Street light outage events reported on weekends and after normal week day business hours are analyzed and dispatched to crews on the following business day. DTE Electric measures both total and crew duration cycle repair periods. Crews authorized by DTE Electric work both day and evening shifts to complete reactive outage repairs of reported street light outage events; and when seasonal work load increases (late August to November and following storms), additional resources are secured and mobilized.

Q24. What other measures does DTE Electric have in place to improve its restoration time and to maintain a high level of customer service?

A24. DTE Electric has established strategic maintenance contracts with the contractors performing the outage restoration work to include financial penalties for not achieving targeted restoration times. Restoration performance, among other metrics, is reviewed with the contractors at monthly performance meetings and, to the extent that restoration performance is not meeting expectations, DTE Electric has shifted responsibility for restoration in certain service territories to alternative contractors to achieve the desired restoration performance. Internally, the

Company evaluates contractor performance metrics in weekly huddles to identify potential performance issues or problem-solving opportunities. Once notified of an outage, DTE Electric contacts the reporting customer to update them on the status of their repair. In addition to these efforts, the Company continues to improve the arrangements for the provision of special order materials on behalf of municipalities that choose streetlight materials that are not included in DTE Electric's standard streetlight offerings.

In an effort to further bolster customer service, in 2019, the Company increased its night patrol activities with the intent to proactively identify and repair outages. At DTE Electric's direction, contractors are now responsible for patrolling all E1 Option I streetlights, with the expectation that each community with streetlights owned and operated by the Company will be visited at least once annually.

Q25. What other activities does DTE Electric employ to minimize outage restoration expense?

A25. On a planned basis, DTE Electric performs periodic group re-lamping of its high pressure sodium on a 9-year cycle. The group re-lamping activity not only improves lighting output, but it also reduces the volume of outage events caused by a failed lamp. DTE Electric does not perform group re-lamping of mercury vapor luminaires as this luminaire technology is obsolete and is being converted to LED upon failure.

In 2015, DTE Electric completed its strategic movement from 24,000 hour lamps (approximately 5-year life) to 40,000 hour lamps (approximately 9-year life) for its high pressure sodium luminaires and is continuing to evaluate the conversion rate from high pressure sodium luminaires to equivalent LED luminaires.

Q26. How does DTE Electric determine how much capital it contributes to prospective projects?

A26. DTE Electric's calculation method for Contributions in Aid of Construction (CIAC) varies depending on whether the DTE Electric project cost is for new business or conversion of existing business (i.e. convert mercury vapor luminaires to LED). The determination of CIAC for new business is calculated as the total estimated project cost less three years of expected incremental revenues from the project based upon the Company's MPSC-approved tariffs. The determination of CIAC for conversion of existing business is the total estimated project cost less three years of expected incremental revenues from the project plus a DTE Electric-provided labor credit. Typically when converting existing fixtures to LED, a credit is not applicable, as the new LED rate and the assoictaed 3 years of revenue are less than the revenue of the existing lighting system being replaced.

Q27. Why does DTE Electric provide a labor credit for planned conversions?

A27. DTE Electric provides a labor credit, equal to the contract labor charge for installation, to both incentivize conversions from the obsolete mercury vapor lighting technology to the LED lighting technology, and to realize the economic efficiencies gained from performing planned conversions of mercury vapor lighting versus reactive conversions upon failure. DTE Electric's contract labor costs for planned conversions are approximately 40% below that for reactive conversions. In addition to the incremental revenue and labor credits, the project cost for

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conversion of existing business may also be eligible for an energy waste reduction (EWR) grant as part of the Company's MPSC-approved EWR program, further offsetting the customer's contribution to the conversion project.

Q28. What is the rationale for providing a three-year revenue credit for qualifying customer projects?

A28. The underlying purpose of reducing the project cost for new business by three years of incremental revenues is to recognize the impact of increased revenues from the project which are ultimately used to offset the revenue requirement associated with the new assets that DTE Electric records to the applicable regulatory account. In the determination of CIAC for planned conversion of existing business, DTE Electric similarly determines total project cost and similarly reduces this amount by 3 years of expected incremental revenues. As I previously stated, because the rates and associated costs for LED lighting are lower than those for equivalent HID lighting, no incremental revenue is available to offset the recovery of the additional assets and therefore, no reduction in CIAC is provided. However, the CIAC impact is reduced because DTE Electric provides a labor credit to customers requesting planned conversion of obsolete mercury vapor lighting, and facilitates the process for receipt of energy waste reduction grants for conversion of existing HID lighting to LED lighting.

Q29. Do DTE Electric's proposed LED rates reflect any capital expense which was offset by CIAC?

A29. No. DTE Electric records customer CIAC as a direct offset to actual capital expense for each of its new business and conversion projects. Therefore, DTE

Electric's proposed LED rates do not reflect any capital expense which was offset by CIAC. For instance, if a customer provides a CIAC payment of $50,000 and actual capital expense was $80,000, then DTE Electric would record net capital of $30,000 on its books for purposes of ratemaking.

Q30. What is DTE Electric's progress to date with respect to conversion of mercury vapor to LED street lighting?

A30. As I mentioned previously, DTE Electric currently has a total remaining population of just under 20,000 mercury vapor street light luminaires. DTE Electric continues to work with its municipal customers in converting these assets to LED lighting. Over the past seven years, DTE Electric has converted approximately 62,000 street lights to LED and is in the process of developing its conversion work for 2022. The implementation of projects to convert mercury vapor to LED for each individual municipality requires evaluation, establishment and execution of contracts, work planning (including the ordering of materials, updating of drawings, receipt of permits, etc.), construction (including field coordination and oversight), and field verification and billing system updates, all of which is labor intensive.

<u>Community Lighting Rate Design</u>

Q31. What does Exhibit A-16, Schedule F3 show?

A31. This exhibit shows the present and proposed rate design and corresponding revenues by rate schedule, based on the billing determinants for the 12 months ending October 31, 2023. The exhibit details the forecasted billing determinants as well as the resulting present and proposed rates and revenues. The various billing components are listed in column (a), and the respective billing determinants, including units of measure, are listed in column (b). The forecasted billing determinants were developed based on historical data and relationships, as well as known and measurable changes, and are consistent with the sales forecast as presented on Company Witness Mr. Leuker's Exhibit A-15, Schedule E2, Other class sales. The existing luminaire and energy rates, both non-capacity energy and capacity energy, as approved in the Order dated May 8, 2020, in Case No. U-20561 are in columns (c), (d) and (e), and are used to calculate the present revenues in column (f). The luminaire rates proposed in this proceeding based upon the lighting cost of service (as discussed in detail below) are in column (g), the proposed non-capacity energy rates are in column (h), the proposed capacity energy rates are in column (i) and the resulting revenues from the new lighting cost of service are in column (j).

Q32. How were DTE Electric's present Municipal Street Lighting and Outdoor Protective Lighting charges determined?

A32. The lighting rates approved in MPSC Case No. U-20561 reflect a monthly energy charge, both non-capacity energy and capacity energy, and a luminaire charge. The monthly energy charge was determined by applying the energy rates, both in cent/kWh, to the calculated consumption values of the various lighting technology lamp sizes for both the E1 and D9 Rate Schedules. The luminaire charge (which includes costs related to customer service charges) is a fixed monthly amount applied to each luminaire dependent on the technology utilized, the lamp size or wattage, the lighting provision and whether it is served from underground or overhead. The total (energy and luminaire) monthly lighting charges that were calculated in MPSC Case No. U-20561 do not fully represent true cost of service rates by technology type (within the lighting rate class). In MPSC Case No. U-20561, the lighting rates were gradually moved towards cost of service with the total movement capped to minimize the impact on any individual customer.

Q33. Did DTE Electric change the methodology by which it allocated the production and distribution revenue requirements to the various lighting rate schedules that you are supporting in this case?

A33. No. Consistent with the methodology employed in Case Nos. U-18014, U-18255, U-20105, U-20162, and U-20561, the functionalized production (Exhibit A-16, Schedule F1.1) and distribution (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by Company Witness Maroun for each of the lighting rates schedules (D9, E1, & E2) were fully allocated to each of those rate schedules within the lighting rate model. The proposed luminaire, distribution, and energy charges (both capacity and non-capacity) within each of the rate schedules were designed to meet the production and distribution revenue requirement for each rate schedule shown in these exhibits. Witness Maroun's Exhibit A-16, Schedule F1.5, detailing how much of the production revenue requirement for each rate class is capacity and non-capacity related, was used to allocate the production revenue requirement between the capacity and non-capacity energy charges. Consistent with the methodology employed in Case Nos. U-18014, U-18255, U-20105, U-20162, and U-20561, the E1 and D9 Rate Schedule energy charges, both capacity and non-capacity, were developed based upon the total production revenue requirement prepared by Witness Maroun for the E1 and D9 Rate Schedules.

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Rate Schedule E1

Q34. How were the proposed E1 Rate Schedule luminaire charges determined?

A34. The Company determined the new luminaire service cost structures listed in the E1 Rate Schedule tariff schedules as shown on Exhibit A-16, Schedule F3 by reviewing and allocating the specific cost of service components to the type of service, underground or overhead, and then further allocating them to the individual lighting technologies. There were no changes in the methodology for the allocation of non-production O&M costs or capital-related costs to luminaire charges proposed in this proceeding.

Q35. How was O&M allocated to the proposed E1 Rate Schedule luminaire charges in the lighting model?

A35. Total Distribution O&M expense reflected in the E1 Rate Schedule luminaire charge is $8.4 million, based upon the Company's cost of service model sponsored by Witness Maroun. This distribution O&M expense is comprised $3.4 million directly assigned to lighting and recorded in account 596 (Street Lights & OPL), $3.0 million allocated to lighting from various distribution operation and distribution maintenance accounts, $0.5 million from various customer service/sales accounts allocated to E1 Rate Schedule lighting and $1.5 million of total A&G expense. Based upon the underlying labor costs within account 596 and the various distribution operation, distribution maintenance and customer service accounts allocated to E1 Rate Schedule lighting, approximately 40%, or $0.6 million, of A&G expense was directly allocated to E1 Option I Rate Schedule lighting and the balance was allocated to the various distribution O&M accounts within E1 Rate Schedule.

The total customer service and distribution O&M expense allocated to lighting, including A&G allocated to these accounts, was further allocated to the various E1 Rate Schedule luminaire/distribution charges based upon the system wattage of the luminaires and lamps. With the exception of group re-lamping, LED washing, post inspection, night patrols and post painting, all O&M ($3.4 million) and A&G ($0.6 million) directly assigned to lighting was spread equally across all luminaires. The O&M associated with LED washing was allocated to LED luminaires (both overhead-fed and underground-fed) based upon the underlying LED saturation and contract cost, O&M associated with post inspection and post painting was spread equally to all underground fed luminaires and O&M for group re-lamping was allocated to metal halide luminaires only.

Q36. How was depreciation expense allocated to the proposed E1 Option I Rate Schedule luminaire charges in the lighting model?

A36. The total depreciation expense reflected in the E1 Option I Rate Schedule luminaire charges, as established in the Company's cost of service model supported by Witness Maroun, is $25.3 million. This reflects $18.5 million depreciation for the directly assigned lighting asset accounts, $2.4 million for the distribution asset accounts allocated to lighting, and the balance associated with general and intangible plant accounts allocated to lighting.

The depreciation expense for overhead subaccount 373.01 (street lighting and signal systems - overhead) was allocated directly to overhead fed luminaires, and depreciation expense for underground subaccount 373.02 (street lighting and signal systems – underground) was allocated directly to underground fed luminaires. The depreciation expense for overhead subaccount 373.03 (Street Lighting wire - OH) was allocated to all overhead luminaires equally. The depreciation expense for underground subaccount 373.04 (Street Lighting Wire/Cable - Underground) was allocated to all underground-fed luminaires equally.

The depreciation expense for both the overhead and underground luminaire subaccounts (LED Overhead, LED Underground, and HID Overhead, HID Underground) was allocated to the respective overhead and underground luminaires based upon lighting technology, wattage and underlying original investment. For instance, all underground-fed mercury vapor luminaires received an allocation of depreciation expense from subaccount 373.05 (Street Lighting Luminaires – HID Underground) based upon the luminaire type's investment and underlying mercury vapor luminaire useful life utilized to establish rates in MPSC Case Nos. U-18014, U-18255, U-20105, U-20162, and U-20561.

The depreciation expense that was allocated to lighting from distribution was allocated to all underground and overhead lighting based upon each luminaire type's system wattage -- the best representation of each lighting type's usage of the distribution system.

Q37. How was the revenue requirement for other taxes, return on investment and income tax allocated to the proposed E1 Option I Rate Schedule luminaire charges?

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A37. Consistent with the allocation performed in DTE Electric's prior five rate cases, all other capital-related components were allocated to the various luminaire types in a manner similar to that employed for the related underlying depreciation expense. For the directly assigned street lighting asset subaccounts, other taxes, return on investment and income tax followed the allocation of net plant to each of the lighting types.

Q38. Do you believe the proposed allocation of costs reflected in the various E1 Option I Rate Schedule luminaire charges is reasonable?

A38. Yes. The methodology utilized in the lighting model to allocate each of the individual cost of service components discretely, rather than in total, more accurately reflects the cost to provide lighting service to underground and overhead assets as well as the various lighting technologies. The usage of the eight separate asset subaccounts for allocation of the capital-related costs results in more accurate rate setting based upon both how the lights are fed as well as the lighting technology, wattage and luminaire investment.

Q39. How were the E1 Option II Rate Schedule charges developed?

A39. The E1 Option II Rate Schedule charges were developed based upon a share of the production revenue requirement allocated by Witness Maroun in the Company's cost of service model to the E1 Rate Schedule, a share of the distribution and customer service revenue requirements allocated by Witness Maroun in the Company's cost of service model to the E1 Rate Schedule and a small allocation of the O&M expense directly assigned to the E1 Rate Schedule from Account 596. The allocations of revenue requirement from production, distribution and customer

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service to the E1 Option II Rate Schedule were accomplished on a per kWh basis across all E1 Option II rates. The proposed rates for the E1 Option II Rate Schedule are displayed in a luminaire charge, similar to that for Rate Schedule E1 Option I, and energy charges, both capacity and non-capacity, in a cent/kWh format.

Q40. How were the E1 Option III Rate Schedule charges developed?

A40. The E1 Option III Rate Schedule charges were developed based upon a share of the total production revenue requirement allocated by Witness Maroun in the Company's cost of service model to the E1 Rate Schedule, a share of the total distribution revenue requirement allocated by Witness Maroun in the Company's cost of service model to the E1 Rate Schedule and a share of the customer service revenue requirement allocated by Witness Maroun in the Company's cost of service model to the E1 Rate Schedule. The allocations of revenue requirement from production, distribution and customer service to the E1 Option III Rate Schedule were performed on an equal energy basis across all E1 Option III rates. The proposed E1 Option III Rate Schedule distribution and energy charges, both capacity and non-capacity, are displayed in a cent per kWh format, allowing for a transparent comparison of lighting costs for the various luminaire system wattages and the various lighting technologies.

Q41. How does your proposed cost allocation methodology impact the present rates for the E1 Rate Schedule?

A41. The cost allocation methodology described above and employed in the lighting model reflects a collective revenue deficiency for the E1 Rate Schedule options. Based upon using the same cost allocations in the lighting rate model that were utilized in the Company's last five rate cases, Rate Schedule E1 lighting rates proposed in this proceeding are collectively below their cost of service.

Q42. What is your proposal regarding rate design in this proceeding for Rate Schedule E1 Option I rates?

A42. Consistent with the final rate design in MPSC Case Nos. U-18014, U-18255, U-20105, U-20162, and U-20561, I have proposed a continuation of the gradual move towards rates which are entirely based upon cost of service for the lighting class. Consensus on this methodology was reached in the lighting collaborative ordered in Case No. U-17767 and beginning with rate Case No. U-18014, the Rate Schedule E1 Option I lighting rates are being gradually moved to rates which are entirely based upon cost of service.

Q43. How were the Rate Schedule E1 Option I proposed rates developed in this proceeding?

A43. The proposed Rate Schedule E1 Option I lighting rates were designed with two goals in mind; (1) continue the gradual move to rates which are entirely cost based and (2) minimize the impact of the proposed lighting rates on the monthly lighting bill for any municipality. Using the lighting rate model, the first step towards achievement of these goals was to limit the overall increase on any municipality and/or total lighting rate to twice the proposed increase in revenue requirement. The second step of the process was to allocate the remaining revenue deficiency for the Rate Schedule E1 Option I class, on a percentage basis, to all the remaining lights.

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<u>Rate Schedule D9</u>

Q44. How were the proposed rates for the D9 Rate Schedule determined?

A44. The proposed luminaire rates for the D9 Rate Schedule for both commercial and residential OPL service were developed based upon the allocated and directly assigned distribution costs supported by Witness Maroun in the Company's cost of service model. The luminaire rate design methodology employed in the lighting model for the D9 Rate Schedule mirrors the methodology employed for the E1 Rate Schedule with all allocated distribution costs assigned to luminaire charges based upon energy consumption and the directly assigned costs allocated based upon the underlying individual cost of service components. As I discussed earlier, the proposed energy charges, both capacity and non-capacity, for the D9 Rate Schedule for both commercial and residential OPL service were developed collectively with the E1 Rate Schedule energy charges.

Q45. Are all of the proposed luminaire rates for the D9 Rate Schedule entirely cost-based?

A45. No. The proposed rates for Rate Schedule D9 required the use of the same two-step methodology to gradually achieve cost-based intra-class rates that was employed for the E1 Option I Rate Schedule.

<u>Rate Schedule E2</u>

Q46. How were the proposed Rate Schedule E2 charges determined?

A46. The Rate Schedule E2 charges were developed based upon the production, both capacity and non-capacity, and distribution revenue requirements allocated to Rate Schedule E2 customers by Witness Maroun in the Company's cost of service

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model. Each of the revenue requirement amounts were divided by the total forecasted energy for the projected test period to arrive at a distribution rate, a non-capacity energy rate and a capacity energy rate in cents/kWh. The total rate approved in MPSC Case No. U-20561 was 8.21 cents/kWh. The total rate proposed in this proceeding is 8.64 cents per kWh which includes a distribution charge of 2.10 cents/ kWh, a capacity energy charge of 1.88 cents/kWh and a non-capacity energy charge of 4.66 cents/kWh.

Q47. How has Witness Maroun's presentation of the revenue deficiency/sufficiency for production presented in this case impacted your rate design?

A47. To allocate the targets to the lighting tariff energy charges, both capacity and non-capacity, in the cost of service-based rate presentation, I have allocated the revenue deficiency for Rate Schedule E2 to the E2 rate directly and I have allocated the total D9 sufficiency, and total E1 deficiency Rate Schedules to those energy rates in total.

Q48. Will you please describe Exhibit A-16, Schedule F8?

A48. This exhibit contains the proposed tariff sheet changes which result from the pricing changes described above.

<u>Proposed Tariff Changes</u>

Q49. Are you proposing any changes to E1 or D9 Outdoor Lighting tariff sheets?

A49. Yes. We are proposing to clarify the tariff language for E1 and D9 customers taking Dusk to Midnight service or Experimental Programmable Photocell service.

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Q50. What changes are you proposing to make to the Dusk to Midnight service and Experimental Programmable Photocell service tariff billing provisions?

A50. We are proposing to add clarifying language to properly reflect how discounts for these two billing provisions are calculated. As currently written, the tariff only includes the discount for the Distribution Charge per lamp, per month for both Dusk to Midnight and Experimental Programmable Photocell services and both do not reflect the Energy Charge savings. To adjust for this, we are proposing to add the <u>*underscored*</u> verbiage to the tariff language:

Dusk to Midnight Service: For service to parking lots from dusk to approximately twelve o'clock midnight E.S.T., a <u>*distribution*</u> discount of 1.060¢ per nominal lamp size wattage per month <u>*and a 50% reduction in the average monthly hours of use*</u> will be applied. One control per circuit <u>*or luminaire*</u> will be provided.

Experimental Programmable Photocell Service: Customers may elect to place luminaires on photocells that are programmable to turn off lights at pre-determined times during the night. A <u>*distribution*</u> discount of 1.060¢ per nominal lamp size wattage per month <u>*and a 50% reduction in the average monthly hours of use*</u> will be applied.

<u>Plan to Reduce Overhead Fed Lighting Costs & Discussion of Technological Effiencies</u>

Q51. What efforts have been undertaken by DTE Electric to control costs for maintaining E1 Option I overhead fed streetlighting?

A51. DTE Electric has focused on three key areas to ensure that costs for maintaining its overhead fed streetlights are minimized: 1) Coordinating the use of night patrols for the purpose of canvassing E1 option I streetlights to proactively identify outages, 2) Working with municipalities who, as part of their agreement chose non-standard luminaires or posts referred to as special order materials (SOM), in an effort to safeguard from depletion of their inventory, and 3) Generating a new revenue stream for safe deployment of 3rd party attachments, for which after-tax revenues would be used to offset E1 Option I revenue requirement.

As previously mentioned, DTE Electric began piloting a formal night patrol process, the intent of which is to proactively identify outages and reduce the number of reactive outages responded to by crews authorized by DTE Electric. Though in the short term, total outage restoration costs may increase because of outages that are identified proactively, number of events and costs over the long term are expected to decrease as a result of outage events being repaired on a planned basis, as opposed to a reactive basis (which may be higher in cost). As night patrols are completed, DTE Electric is cataloging data to identify outages as a percentage of total E1 Option I streetlights by city or municipality, the nature of the outage (i.e. lamp failure, cable failure), and where the outages are occurring. This information will then be used to exercise warranty provisions for premature luminaire failures, as well as targeting specific circuits subject to recurring failures for capital replacement projects, thereby reducing long term maintenance costs.

DTE Electric completed in 2020, a joint review of all city and municipal agreements for which “Special Order Material” (SOM) is included, and where a minimum stock level to be maintained by the city or municipality is specified. This joint review was intended to reaffirm city or municipal minimum reorder points for SOM materials and have this material available to DTE Electric when an SOM related outage occurs. Several of DTE Electric's follow-up outage defects are attributable to the lack of SOM inventory, and average significantly higher restoration times when inventory is unavailable. In addition to extended outages, DTE Electric will typically incur the cost for multiple trip charges when the city or municipality does not have SOM material in stock. We are also working with cities and municipalities to provide standard stock options to those who no longer want to maintain SOM materials. As cities and municipalities begin to restock their inventories or transition to standard stock options, we expect to see a reduction in cost and outage duration associated with SOM streetlights.

Lastly, DTE Electric has negotiated agreements that allow 3rd party attachments to municipal streetlights. Each attachment will require a permit to be issued by both DTE Electric as well as the city or municipality in which the proposed attachment will be made. DTE Electric requires that the 3rd party submit a passing structural analysis, certified by a professional engineer prior to the issuance of a permit. Rental revenues generated from each attachment will be recorded in account 454, Rent from Electric Property, and allocated to E1 Option I Rate Schedule. Rental revenues will reduce the revenue requirement for E1 Option I customers.

Q52. What efficiencies have been gained through the use of technology?

A52. As part of DTE Electric's plan to address and increase reliability of our grid, the Advanced Distribution Management System (ADMS) project is currently being implemented. One of the components of ADMS, referred to as the Outage Management System (OMS), will target efficiencies through improved reporting and data tracking specific managing outage restoration events. The current system used to manage outage events will be retired in 2022 and be replaced with several new tools as part of OMS. The goal is to provide an integrated platform whereby our mapping and job tracking will be linked. This will reduce the likelihood for errors by no longer having to transfer data between multiple systems. We expect that this will also reduce restoration costs by eliminating multiple events being created for the same location and allow for us to know in real time where our crews have been dispatched. Refer to the testimony of Company Witness Elliott-Andahazy for additional information pertaining to ADMS and OMS.

Finally, we continue to evaluate vendor proposals for a smart streetlight network that would allow for real-time feedback significant load changes, service interruptions, and outages specific to streetlights. A key factor in this evaluation process is the initial capital investment cost as well as ongoing O&M costs to maintain a smart network, and the impact on rate design to our municipal customers. As previously mentioned, we are piloting a night patrol process that will canvass cities and municipalities to proactively identify outage events as a cost-effective alternative until a decision is made on implementing a smart streetlight network.

Q53. Does this complete your direct testimony?

A53. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate Schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHAWN D. BURGDORF

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHAWN D. BURGDORF

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Shawn D. Burgdorf. My business address is 414 S. Main Street, Suite 300, Ann Arbor, Michigan 48104. I am employed by DTE Electric Company (DTE Electric or Company).

Q2. What is your current position with the Company?

A2. I am currently the Manager of the Power Supply Strategy & Modeling team within the Generation Optimization department.

Q3. What is your educational background?

A3. I received a Bachelor of Science Degree in Mechanical Engineering from University of Michigan in 2005. I also received a Master of Business Administration Degree from Eastern Michigan University in 2016.

Q4. Do you hold any certifications?

A4. Yes. I am certified as a North American Electric Reliability Council (NERC) Certified System Operator for balancing and interchange. I have also attended Utility Rate School and the Advanced Regulatory Studies Program, both hosted by the National Association of Regulatory Utility Commissioners (NARUC) and The Institute of Public Utilities Michigan State University.

Q5. What is your work experience?

A5. After receiving my Bachelor’s degree from the University of Michigan in 2005, I was employed by Consumers Energy Company (Consumers Energy). During my initial employment at Consumers Energy, I worked in their production cost

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modeling group where I supported the development of power supply forecasts using the PROMOD® model as the basis. In 2009, I transferred positions into the Transmission and Regulatory Strategies Department. In this role, I was responsible for monitoring and analyzing filings by the Midcontinent Independent System Operator, Inc. (MISO) at the Federal Energy Regulatory Commission (FERC). I was also responsible for forecasting future transmission and certain energy market-related costs in Power Supply Cost Recovery (PSCR) proceedings before the Michigan Public Service Commission (Commission or MPSC).

In 2012, I began my employment at DTE Electric within the Generation Optimization Department. In 2015, I was promoted to a Supervisor position and subsequently in October 2018, I was promoted to my current Manager position within Generation Optimization.

Q6. What are your duties and responsibilities in your current position?

A6. My current responsibilities include acquisition of wholesale electric power supply to reliably and economically serve the energy and capacity requirements of the Company's customers including: optimization of the Company's generation assets, including renewable energy facilities, within the wholesale power market; management of emission allowance procurement; management of resource adequacy processes; modeling the DTE Electric generation fleet; optimizing financial transmission rights; and review and advocacy of the Company's recommendations regarding proposed MISO rules, regulations, and business practices.

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Q7. Have you previously provided testimony before the MPSC?

A7. Yes. I sponsored testimony in the following MPSC cases:

U-16149	Consumers Energy’s 2010-2011 Gas Cost Recovery (GCR) Plan
U-16485	Consumers Energy’s 2011-2012 GCR Plan
U-16924	Consumers Energy’s 2012-2013 GCR Plan
U-16890	Consumers Energy’s 2012 PSCR Plan
U-17097-R	DTE Electric’s 2013 PSCR Reconciliation
U-17319-R	DTE Electric’s 2014 PSCR Reconciliation
U-17632	DTE Electric’s 2013 Renewable Energy Plan Reconciliation
U-17680	DTE Electric’s 2015 PSCR Plan
U-17793	DTE Electric’s 2015 Amended Renewable Energy Plan
U-17804	DTE Electric’s 2014 Renewable Energy Plan Reconciliation
U-17920	DTE Electric’s 2016 PSCR Plan
U-17680-R	DTE Electric’s 2015 PSCR Reconciliation
U-18111	DTE Electric’s 2016 Amended Renewable Energy Plan
U-18082	DTE Electric’s 2015 Renewable Energy Plan Reconciliation
U-18143	DTE Electric’s 2017 PSCR Plan
U-17920-R	DTE Electric’s 2016 PSCR Reconciliation
U-20069	DTE Electric’s 2017 PSCR Reconciliation
U-20221	DTE Electric’s 2019 PSCR Plan
U-20471	DTE Electric’s 2019 Integrated Resource Plan
U-20561	DTE Electric’s 2019 Main Rate Case
U-18091	DTE Electric’s 2021 PURPA Avoided Cost

Q8. What is the purpose of your testimony in this proceeding?

A8. The purpose of my testimony is to establish the projected wholesale market energy sales revenue net of fuel including the reconciliation of costs in 2020. To do this, I projected capacity-related generation costs in the 2022 PSCR Plan, projected 2022 wholesale market revenues from energy and ancillary services sales from the Company's capacity resources, and the fuel related cost associated with the Company's capacity resources. This information is used by Company Witness Mr. Maroun in his calculation of cost of service.

I will also provide an overview of: 1) the MISO resource adequacy requirements and capacity market, 2) the capacity import limit (CIL) enforced by MISO in the Planning Resource Auction (PRA) and its impact on Zone 7, and 3) the MISO Zone 7 capacity position for Planning Years 2020/21 and 2021/2022, as well as a forecasted capacity position for Planning Year 2025/26.

Finally, I will discuss the Commission ordered Net Present Value Revenue Requirement (NPVRR) or economic evaluation analysis completed on the Belle River Power Plant.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B6.1	Belle River Power Plant 2026 NPVRR Analysis
A-12	B6.2	Belle River Power Plant 2028 NPVRR Analysis

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A-12	B6.3	Belle River Power Plant 2030 NPVRR Analysis
A-26	P1	Projected 2022 PURPA Capacity-Related Generation Cost
A-26	P2	Projected 2022 PA295/PA342 Capacity-Related Generation Cost
A-26	P3	Projected 2022 Capacity-Related Generation Cost & Energy Sales Revenue Net of Fuel Cost Including 2020 Reconciliation
A-26	P4	2020 Energy Sales Revenue Net of Fuel Cost

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. Section 6w(3)(A) of Act 341 requires that for rate design purposes the capacity charge include capacity-related generation costs in the Company's PSCR mechanism. What are the capacity-related generation costs included in the Company's PSCR mechanism?

A11. The Company's PSCR mechanism includes capacity-related generation costs associated with Public Utility Regulatory Policies Act of 1978 (PURPA) power purchase agreements, PA295/PA342 Company-owned renewable energy systems, PA295/PA342 renewable energy contracts, and capacity purchases.

Q12. How did the Company project the 2022 capacity-related generation costs for PURPA power purchase agreements as included in its PSCR plan filing in Case No. U-21050?

A12. The Company's PURPA contracts have three rate components: fixed, operation and maintenance (O&M), and variable. The projections for both the fixed and O&M components were included in the capacity-related generation costs. The total projected 2022 PURPA capacity-related generation cost is $11.1 million as shown on Exhibit A-26, Schedule P1.

Q13. What costs associated with PA295/PA342 Company-owned renewable energy systems and power purchase agreements are included in the PSCR?

A13. The portion of the cost of PA295/PA342 Company-owned renewable energy systems that is passed through the PSCR Transfer Price mechanism is the approved Transfer Price Schedule or the levelized cost of energy for the renewable energy systems. The portion of the cost of PA295/PA342 power purchase agreements (i.e., non-Company owned) that is passed through the PSCR mechanism is the lower of the Transfer Price approved for the power purchase agreement and the contract price of the agreement.

The Transfer Price is a proxy for the incremental non-renewable capacity and energy expense that would be passed on to the customer if the renewable energy resource was not developed. The relevant statute explains that when setting the Transfer Price, the Commission shall consider factors including, but not limited to, projected capacity, energy, maintenance, and operating costs, information filed under Section 6j of 1939 PA 3 (MCL 460.6j), and wholesale market data including, but not limited to, locational marginal pricing.

Q14. How did the Company project the 2022 capacity-related generation costs for PA295/PA342 company-owned renewable energy systems and power purchase agreements?

A14. The capacity-related generation cost for PA295/PA342 Company-owned and non-Company-owned renewable energy systems and power purchase agreements is the approved Transfer Price fixed component for each specific renewable energy system. The total projected 2020 PA295/PA342 capacity-related generation cost is $113.1 million as shown on Exhibit A-26, Schedule P2.

Q15. How did the Company project the 2022 cost of capacity purchases?

A15. The Company included the net capacity purchase costs based on the 2022 PSCR Plan forecasted expense for the calendar year 2022. The expense includes the Company's net transactions within the MISO annual Planning Resource Auctions (PRA) covering the 2022 calendar year[1]. Consistent with the amount filed in Case No. U-21050, the total projected cost of capacity purchases is $0.8 million as shown on Exhibit A-26, Schedule P3, line 6.

Q16. How did the Company calculate the projected 2022 energy sales revenue net of projected fuel costs per Section 6w(3)(B) of Act 341?

A16. Section 6w(3)(B) of Act 341 requires that the revenue, net of projected fuel costs, from energy market sales, off-system energy sales, ancillary services sales, and energy sales under unit-specific bilateral contracts be subtracted from the Company's capacity costs before calculating its capacity charge. I performed the calculation consistent with the method as directed by the Commission in Case No.

[1] MISO annual resource adequacy auctions cover the Planning Year from June 1st – May 31st. The 2021/22 Planning Year auction covers January 1st – May 31st, 2022 and the 2022/23 Planning Year auction covers June 1st – December 31st, 2022.

U-20162 using the forecasted assumptions from the Company's 2022 PSCR Plan. To calculate the energy sales revenue net of projected fuel related costs, first the projected wholesale energy revenue from the Company's generation resources (including power purchase agreements) was determined (Exhibit A-26, Schedule P3, line 11). Next, the projected wholesale revenue associated with ancillary services provided by the Company's generation resources was determined (Exhibit A-26, Schedule P3, lines 14 and 15). Finally, all fuel and fuel related expenses associated with the wholesale energy and ancillary services were determined (Exhibit A-26, Schedule P3, lines 20 - 23) and subtracted from the projected wholesale revenues (Exhibit A-26, Schedule P3, line 16) resulting in the energy sales revenue net of projected fuel related costs (Exhibit A-26 Schedule P3, line 26).

Q17. What is the projected revenue associated with wholesale energy sales from the Company's generation resources in 2022?

A17. The Company receives wholesale energy revenues from the MISO wholesale energy market for the electricity produced by its generation assets. The wholesale energy revenues forecasted for all Company assets (including PPAs) in the Company's 2022 PSCR Plan (U-21050) was calculated to be $1.682 billion shown on Exhibit A-26, Schedule P3, line 11. This was done by summing the hourly generation multiplied by the corresponding hourly market price.

Q18. Is the Company projecting any off-system energy sales or sales under unit specific bilateral contracts in 2022?

A18. No. These values are shown as zero on Exhibit A-26, Schedule P3, lines 12 and 13.

Q19. What is the projected ancillary services revenue from the Company's generation resources in 2022?

A19. The Company receives wholesale revenue for providing the following ancillary services: regulation reserves, spinning reserves, and supplemental reserves (all settled via MISO's energy and ancillary services market) and reactive reserves (settled per Schedule 2 of the MISO tariff). The Company's 2022 PSCR Plan projected that Company's generation resources would generate $1.5 million of wholesale revenue associate with regulation, spinning, and supplemental reserves and $10.8 million of revenue associated with Schedule 2 reactive reserves. The projected wholesale ancillary services revenues from the Company's generation resources in 2022 are shown on Exhibit A-26, Schedule P3, lines 14 and 15.

Q20. What is the total projected wholesale energy sales revenue including ancillary services in 2022?

A20. The total projected wholesale energy sales revenue including ancillary services in 2022 is $1.694 billion as shown on Exhibit A-26, Schedule P3, line 16.

Q21. What is the projected fuel and fuel related cost required to generate the projected wholesale energy and ancillary services sales from the Company's generation resources in 2022?

A21. The projected fuel and fuel related cost required to make the energy and ancillary services market sales is projected from the generation in the 2022 PSCR Plan and

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includes: fuel, emission allowance expenses, fuel chemical expenses, Schedule 17 market administration expense, variable component of power purchase agreements, and the variable component of renewables (based on removing the fixed component of the MPSC-approved transfer prices from the overall transfer price). Total projected fuel and fuel related costs for the Company's generation fleet are $798.9 million as shown on Exhibit A-26, Schedule P3, line 24.

Q22. What are the Schedule 17 market administration costs associated with the projected wholesale energy sales described above that should be netted against the wholesale revenue?

A22. MISO incurs costs when providing the following services including, but not limited to: 1) market modeling and scheduling functions; 2) market bidding support; 3) locational marginal pricing support; 4) market settlements and billing; 5) market monitoring functions; and, 6) simultaneous co-optimization for the scheduling and enabling of the least-cost, security-constrained commitment and dispatch of Generation Resources to serve Load and provide Operating Reserves in the MISO Balancing Authority Areas while also establishing a spot energy market. MISO recovers these Energy and Operating Reserve Markets Support Administrative Service Cost through a recovery adder filed as Schedule 17 in the MISO tariff. The projected Schedule 17 rate for 2022 is $0.0843/MWh, so the Schedule 17 administration fees associated with the projected generation in 2022 is $3.7 million as shown on Exhibit A-26, Schedule P3, line 23. These expenses need to be included as they would not be incurred if the generation sales did not occur.

Q23. What was the Company's actual wholesale energy sales revenue net of fuel related costs in 2020?

A23. I calculated the Company's actual wholesale energy sales revenue net of fuel related costs in 2020, which is shown on Exhibit A-26, Schedule P4, line 12, column (c). That actual amount was $245.3 million less than the projected wholesale energy sales revenue net of fuel related costs embedded in the Company's rate design in effect in 2020.

Q24. What is the Company's projected wholesale energy sales revenue net of projected fuel costs per Section 6w(3)(B) of Act 341 for 2022 including the reconciliation of 2020?

A24. The total projected 2022 wholesale energy sales revenue of $1.694 billion, net of $0.799 billion in fuel related costs equates to $895 million wholesale energy sales revenue net of fuel related costs as shown on Exhibit A-26, Schedule P3, line 26. The reconciliation of the net sales benefit difference for 2020 of $245.3 million (Exhibit A-26, Schedule P4, Line 12, column (d)) was subtracted from the 2022 projection resulting in an amount of $649.9 million (Exhibit A-26, Schedule P3, Line 28). This amount was provided to Company Witness Maroun to develop his capacity related cost of service.

Overview of the Resource Adequacy Requirements and Capacity Market

Q25. Who establishes the resource adequacy planning requirements with which the Company must comply?

A25. Resource adequacy requirements are governed by a combination of the North American Electric Reliability Corporation (NERC), MISO, and the MPSC. The MISO tariff requires the Company to develop a resource adequacy plan that

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complies with the reliability standards set forth by the NERC. NERC Standard BAL-502-RFC-02 "Planning Resource Adequacy Analysis, Assessment and Documentation" requires the Planning Coordinator to calculate a planning reserve margin for each planning year. MISO is the Planning Coordinator for the Midcontinent ISO region. MCL 460.6w (PA 341) requires the Company to demonstrate, annually, that it will have sufficient resources to meet its projected planning reserve margin on a four-year forward basis. This Michigan requirement is intended to ensure proper longer-term planning for resource adequacy, which is not the case with MISO's one-year annual planning cycle as further discussed in my testimony.

Q26. How are capacity planning reserve margin requirements established by MISO?

A26. Each year, MISO establishes a Planning Reserve Margin (PRM) which is the amount of capacity above the expected weather-normalized peak demand required to reliably serve load in the entire MISO region. A PRM is intended to maintain reliable operation while meeting unforeseen events such as extreme weather and unexpected capacity outages. The PRM is established by performing a Loss of Load Expectation (LOLE) study which considers factors including, but not limited to: generator forced outage rates, generator planned outages, expected performance of load modifying resources, load forecasting uncertainty, and transmission system import and export capabilities. The PRM is established using a LOLE of 1 day per 10 years which is the industry standard.

Q27. How does MISO implement its resource adequacy requirements?

A27. MISO's resource adequacy requirements are annual and implemented for the immediately upcoming planning year only. Every year, Load Serving Entities (LSE) in MISO are required to demonstrate compliance with their Planning Reserve Margin Requirement (PRMR), which is their forecasted peak demand (coincident with the MISO's peak demand) plus the required PRM. The PRMR compliance process is executed by MISO in the spring immediately prior to the planning year that begins on June 1. MISO LSEs must meet their PRMR through a combination of: submitting a Fixed Resource Adequacy Plan (an LSE's plan showing rights to sufficient resources to meet its PRMR), purchasing capacity through MISO's PRA at the same time as separately selling or self-scheduling (offering into the auction at a price of zero as a "price taker") any capacity they may own, or paying a capacity deficiency charge.

MISO's PRA does not guarantee the availability of capacity and if there are insufficient resources to meet demand in the PRA, resource adequacy will not be achieved. In fact, a capacity shortage situation could easily arise because MISO's PRA is for a term of only one Planning Year and it is performed only two months prior to that Planning Year, whereas the planning and construction of new generating capacity can take several years. When LSEs properly plan for the long-term capacity needs of their customers, the PRA works as a residual auction for the upcoming Planning Year by providing a means to buy and sell small amounts of capacity needed due to normal variances in load and generation.

Q28. How does MISO implement local reliability requirements?

A28. MISO developed Local Resource Zones (LRZs) based on criteria including electrical boundaries, state boundaries, transmission interconnections and geographic boundaries. There are ten LRZs within MISO and the Company's service territory is in LRZ 7 which is comprised of most of the lower peninsula of Michigan. As part of MISO's annual LOLE study, the CIL and Capacity Export Limit (CEL) of each LRZ are determined along with the Local Clearing Requirement (LCR), which is the minimum amount of unforced capacity (UCAP, the amount of capacity assigned to a resource utilizing historic availability) that must be physically located within a LRZ in order to maintain reliability. Simply stated, to reliably serve load a minimum amount of capacity must be located near the load due to the limitations of the transmission system to import additional capacity.

When conducting the PRA, MISO enforces the LCRs, CILs and CELs using a multi-zone optimization methodology and commits capacity up to the PRM requirements of all LSEs. Because both the LCR and PRMR must be enforced in the PRA to ensure a reliability of 1 day per 10 years LOLE, the actual amount of capacity imports that clear in the PRA can be constrained further than the CIL resulting in an effective CIL, which I refer to as ECIL, which is calculated by the following formula: ECIL = PRMR - LCR. This ensures that sufficient existing resources are committed, if available, in each LRZ to reliably serve load.

The PRA Auction Clearing Price (ACP) is procedurally set to the maximum clearing price of the Cost of New Entry (CONE) when there is insufficient capacity to meet the LCR of a zone <u>or</u> the total PRMR for the MISO footprint. CONE is an industry-wide term used to indicate the current, annualized, capital cost of constructing a hypothetical advanced combustion turbine (CT).

Overview of the Effective Capacity Import Limit (ECIL) for MISO Zone 7

Q29. What was the Zone 7 ECIL for Planning Years 2020/21 and 2021/22 as well as what is projected for 2022/23?

A29. The Zone 7 ECIL was 95 MW (ECIL = PRMR – LCR = 21,945 – 21,851 = 95 MW) using MISO PRA results for Planning Year (PY) 2020/21 and 1,749 MW for Planning Year 2021/22. This means that for PRA purposes, only 95 MW of capacity resources from outside LRZ 7 could be used to meet the Zone 7 PRMR requirement without violating the LCR constraint in PY 2020/21 while that amount changed significantly in a single year to 1,749 MW in PY 2021/22. The projected ECIL for PY 2022/23 is ~773 MW which further demonstrates the volatility of ECIL by a projected drop of ~1,000 MW for PY 2022/23 from PY 2021/22.

Q30. Do you have concerns about relying on imports and the ability to import capacity external to Zone 7?

A30. Yes. The ECIL can be utilized by all LSEs in LRZ 7. However, there is currently no allocation process; thus, uncertainty exists on the ECIL availability that can be relied upon by an individual LSE. This can result in reduced reliability if LSEs count on too much imported capacity and collectively exceed the ECIL. The historical variability in MISO resource planning requirements (e.g. the large change in ECIL over the past two PYs) poses both a reliability (not meeting federal reliability standards) and cost risk by relying on resources external to Zone 7. Customers are exposed to the potential of additional costs when using resources

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outside of Zone 7 to meet resource adequacy requirements. For example, when non-Zone 7 capacity is used, the Company would receive the ZRCs from this out-of-zone resource and use the ZRCs to meet its Zone 7 capacity requirement to serve customer demand. However, if the Zone 7 auction clearing price is CONE due to insufficient resources to meet the LCR, customers may be subject to a Zonal Deliverability Charge. This charge occurs when there is a difference in the auction clearing price between the MISO zone in which the resource is located and the zone in which the LSE is located.

Overview of the MISO Zone 7 Capacity Position for Planning Years 2020/21, 2021/22 and Forecasted Capacity Position for Planning Year 2025/26

Q31. What were the PRA results for MISO Zone 7 in Planning Years 2020/21 and 2021/22?

A31. MISO Zone 7 did not meet its LCR for Planning Year 2020/21. This resulted in the Zone 7 price clearing at the auction maximum CONE ($94,000/MW-year) and was the first time that any Zone in MISO has not met its resource adequacy requirements since the beginning of the MISO annual capacity construct in 2013. The Zone 7 resource adequacy shortfall indicated the local reliability in Zone 7 was worse than the federal reliability standard of a 1 day in 10 years loss of load event. MISO Zone 7 did meet its LCR for Planning Year 2021/22 which shows the variability in changing planning requirements from year to year.

Q32. How have the total Zone 7 resources changed over the past few Planning Years?

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A32. The UCAP value of all resource types in Zone 7 has seen a slight decrease over the past few Planning Years. Table 1 shows the total resource UCAP values in Zone 7 by Planning Year.

Table 1: Zone 7 Resources (MW) by Planning Year (PY)

Description[1]	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22
Zone 7 Resources	22,036	22,063	21,728	21,666

1) Data from actual MISO summaries of PRA results

Q33. Are there any significant capacity resource additions/retirements expected for MISO Zone 7 between Planning Year 2021/22 and Planning Year 2025/26?

A33. Yes. DTE Electric is commissioning the Blue Water Energy Center in Planning Year 2022/23 along with retiring the remaining St. Clair units and Trenton Channel 9 unit. DTE Electric plans to add renewable generation of approximately 801 MW of UCAP over the Planning Years 2022/23 through 2025/26. Additionally, Consumers Energy has filed an Integrated Resource Plan on June 30, 2021 (MPSC Case U-20190) with significant changes to their resource mix.

The most recent capacity demonstration report published on March 26, 2021 by the MPSC in Case No. U-20886 shows total Zone 7 resources at 21,943 MW for Planning Year 2024/25. This capacity demonstration report does not extend beyond Planning Year 2024/25, so I held the Zone 7 resources flat for the Planning Year 2025/26. I believe this value, adjusted to 21,623 MW (Table 5, Line 6) for known DTE Electric capacity value changes, risk of delays in DTE renewable build plan, and adjustments for Consumers IRP filed on June 30, 2021 to be a reasonable forecast for Planning Year 2025/26. Considering the extensive addition of

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renewable generation in the near-term Zone 7 forecast, there is the potential for renewable project delays (both on project construction and transmission upgrades) which risk not being completed prior to PY 2025/26. I accounted for this risk with an assumption of a single renewable facility being delayed (~247 MW UCAP) to develop the Zone 7 resource projection for PY 2025/26 as shown in Table 5.

Q34. What is the MISO Zone 7 Local Reliability Requirement (LRR)?

A34. The LRR represents the minimum amount of UCAP for an LRZ to meet its LOLE without considering transmission ties to systems outside of the LRZ. The LRR is a part of the equation to calculate the LCR. Holding all else equal, a higher LRR results in a higher amount of capacity resources required to be located in a MISO Zone. The equations for LRR and LCR are as follows:

LRR = (Per-Unit LRR) * Zonal Peak Demand

LCR = LRR – CIL - controllable exports by MISO

In recent years, there have been no controllable Zone 7 exports and the equation simplifies to LCR = LRR – CIL.

Q35. How has the Per-Unit LRR changed over the past few Planning Years and what is a reasonable forecast for Planning Year 2021/22?

A35. The historical Per-Unit LRR values for the past few Planning Years are shown in Table 2. The Per-Unit LRR has shown an upward trend from 115.3% in Planning Year 2018/19 to 121.2% in the most recent 2021/22 Planning Year.

Table 2: Zone 7 Historical Per-Unit LRR by Planning Year (PY)

Description	2018/19	2019/20	2020/21	2021/22
Zone 7 Per-Unit LRR[1]	115.3%	117.2%	119.5%	121.2%

1) Source: MISO LOLE reports published for corresponding Planning Years

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There are many factors that MISO considers in its LOLE analysis when determining reserve margins which include weather and economic uncertainty, load, and generation. MISO completed their LOLE analysis for PY 2022/23 and have published a Per-Unit LRR value of 119.4%. Even though the Per-Unit LRR dropped slightly, it has been trending upward in the recent past as shown in Table 2. I believe holding flat the current 119.4% in projecting PY 2025/26 as a reasonable and possibly conservatively low value.

Q36. How has the Zone 7 Peak forecasted demand changed over the past few Planning Years and what is a reasonable near-term peak demand forecast?

A36. The Zone 7 peak forecasted demand values over the past few Planning Years indicate a near-term downward trend as shown in Table 3.

Table 3: Zone 7 Historical Forecasted Peak Demand (MW) by Planning Year

Description	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22
Zone 7 Peak Demand[1]	21,174	21,350	20,963	20,296

1) PY 2018/19, PY 2019/20, PY 2020/21, PY 2021/22 data from preliminary PRA data published by MISO in corresponding years

The recent COVID-19 driven recession lowered DTE Electric's load forecast for Planning Year 2021/22 from recent years. However, DTE Electric is forecasting a higher peak load demand for Planning Year 2022/23. To forecast Zone 7 peak demand for Planning Year 2025/26, I removed DTE Electric's peak demand forecast used for Zone 7 in the 2020 MISO LOLE report for PY 2025/26 and added back DTE Electric's current (as of this case filing) peak demand forecast developed by

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Company Witness Leuker to determine a Zone 7 peak of 20,399 MW (Table 5, Line 1).

Q37. Does DTE Electric believe the MISO Zone 7 CIL will change significantly from the Planning Year 2022/23 value in Planning Year 2025/26?

A37. It is uncertain how the CIL value will change in the future as historical values for CIL have changed significantly year over year. The Table 4 shows the variability in CIL values in recent years.

Table 4: Zone 7 Historical CIL value by Planning Year (in MWs)

Description	2018/19	2019/20	2020/21	2021/22	2022/23
Zone 7 CIL[1]	3,785	3,211	3,200	4,888	3,749

1) Source: MISO LOLE reports published for corresponding Planning Years

Q38. What were the MISO Zone 7 resources compared to the LCR for Planning Years 2020/21, 2021/22 and what is your projection for potential MISO Zone 7 resources compared to the LCR for Planning Years 2022/23 and 2025/26?

A38. Table 5 shows the actual MISO Zone 7 resource position compared to the LCR for Planning Years 2020/21 and 2021/2022. Table 5 also shows the forecasted MISO Zone 7 resource positions compared to the forecasted LCR for Planning Years 2022/23 and 2025/26. The information in the table below is based on MISO data from the 2021 LOLE report updated for DTE Electric peak demand changes, MISO data from the Planning Year 2022/23 LOLE Results, MISO's PRA results for Planning Years 2020/21 and 2021/22 and the MPSC Staff Report for Zone 7 capacity demonstrations in Case U-20886 updated for DTE Electric resource changes for Planning Years 2022/23 and 2025/26 and adjustments to Zone 7 resources for PY 2025/26 to reflect Consumers Energy's IRP filed on June 30, 2021.

Table 5: Planning Years 2020/21, 2021/22, forecasts for 2022/23 and 2025/26

Line #	Description	PY 2020/21	PY 2021/22	PY 2022/23	PY 2025/26
1	Zone 7 Peak Demand	20,963	20,296	20,752[1]	20,399[1]
2	LRR Unforced Capacity per-unit of Peak Demand[2]	119.5%	121.2%	119.4%	119.4%
3	Local Reliability Requirement (LRR = Line 1 x Line 2)	25,051	24,598	24,778	24,356
4	Capacity Import Limit (CIL)	3,200	4,888	3,749[3]	3,200 -4,888[4]
5	Local Clearing Requirement (LCR = Line 3 - Line 4)	21,851	19,710	21,029	19,468 - 21,156
6	Zone 7 Resources	21,728	21,666	21,537[5]	21,623[6]
7	Anticipated LCR Position (Line 6 - Line 5)	(123)	1,956	508	467 - 2,155
8	Anticipated LCR Position without Belle River (Line 7 - 1,215 MW UCAP)				(748) - 940

(1) Value based on 2020 LOLE Study Report updated for DTE peak load changes
(2) LRR is based on PY 2022/23 value in MISO's Planning Year 2022/23 LOLE Study Report
(3) CIL is based on PY 2022/23 value in MISO's Planning Year 2022/23 LOLE Study Report
(4) CIL is based on historic range of CIL values
(5) Value based on U-20886 MPSC Staff Report and Recommendations updated for DTE resource changes
(6) Value based on U-20886 MPSC Staff Report and Recommendations updated for DTE resource changes, risk of delays in DTE renewable build plan, and adjustments for Consumers IRP filed on June 30th, 2021

Q39. Do you have any concerns about the forecasted MISO Zone 7 capacity resources compared to the projected LCR for Planning Years 2022/23 and 2025/26?

A39. Yes. Table 5 shows that Zone 7 was short of its LCR in Planning Year 2020/21 and long of its LCR in PY 2021/22. The fact that Zone 7 fell short of its LCR in Planning Year 2020/21, the recent variability in MISO's CIL year-over-year, the changing resource mix in Zone 7, as well as siting and supply chain risks affecting deployment of new renewable resources, presents a potential reliability concern that Zone 7 may not have enough resources to meet its LCR in Planning Years 2022/23 and 2025/26. Unexpected outages that lead to capacity dis-accreditation, timing to bring new generation online and changes in resource accreditation (particularly for renewable resources as their penetration within MISO increases) are additional risks that may contribute to Zone 7 falling short of capacity in the near future. Should Zone 7 fall short of capacity and thus the LCR not met, the MISO auction clearing price for Zone 7 would be set at CONE (**as was the case in Planning Year 2020/21**) and the probability of a loss of load event (an event in which available capacity is insufficient to serve demand) would exceed the federal reliability standards that govern the resource adequacy planning process.

Q40. What contribution does the Company's Belle River Units have on the amount of local generation capacity in PY 2025/26?

A40. The Company's Belle River Power Plant provides approximately 1,200 MWs of UCAP towards meeting the MISO Zone 7 LCR in Planning Year 2025/26. The ability to reliably serve load in Zone 7 may be compromised if the Belle River units were not available. As previously discussed, if Zone 7 does not meet the LCR, the MISO auction clearing price for Zone 7 would be set at CONE and the probability of a loss of load event would exceed the federal reliability standards that govern the resource adequacy planning process.

Belle River Power Plant (BRPP) Economic Evaluation

Q41. Has the Company completed an economic analysis regarding continued operations of the Belle River Power Plant (BRPP)?

A41. Yes. In the Order in Case No. U-20561 issued May 8, 2020, the Commission ordered that a NPVRR analyzing BRPP using alternative retirement dates be included in the Company's next rate case. BRPP consists of two units, Units 1 and

2. The Company has completed a NPVRR analysis, the results of which are summarized on Exhibit A-12, Schedules B6.1 - B6.3.

Q42. What alternative retirement dates did the Company analyze?

A42. The NPVRR analysis of BRPP consisted of the following options:

- Retire BRPP in May 31, 2030
- Retire BRPP May 31, 2028
- Retire BRPP May 31, 2026
- Retire BRPP May 31, 2023

Q43. How did the Company structure its NPVRR analysis?

A43. For the NPVRR analysis, the Company assessed the incremental benefits and costs for four retirement options and calculated the net difference between the NPVRR of each option.

A NPVRR was calculated for each sensitivity in each retirement analysis. A summary of the sensitivities for each analysis is shown in Exhibit A-12, Schedule B6.1 - B6.3, page 2 of 6. A total of four NPVRR sensitivities were examined with capacity price inputs ranging from $0 to CONE at $94.80/kW-year. In each sensitivity, each retirement option incorporates the benefits and costs of specific value components. The total benefit and cost of each component for each option is summarized on pages 3 through 6 in lines 4 and 5, columns (b) through (g) with the total and overall NPVRR listed in column (h), line 6. Line 7, columns (b) through (p) list each year and lines 10 through 16, column (a) provides the value components that are included: operations and maintenance (O&M) expense, fuel costs, energy and capacity purchases, capital investment, and property tax expense. The resulting net difference between the NPVRR of each component is listed in column (q) and summed up in line 16.

Each NPVRR sensitivity considered assumptions listed on Exhibit A-12, Schedule B6.1 - B6.3, page 1 of 6. The assumptions for this analysis have been provided by the respective subject matter experts in the Company. My team provided the inputs on the generation and market price assumptions. Refer to Company Witness Morren for additional detail on the Capital and O&M assumptions included in the analyses and Company Witness Wisnewski provided the property taxes.

Q44. What sensitivities did the Company perform regarding the capacity price inputs for the NPVRR analysis?

A44. Four sensitivity calculations were used for the capacity price input in the NPVRR analysis. For capacity purchases, in the case of necessary capacity replacement for the option of retiring the plants prior to 2030, the Company considered the pricing alternatives of zero ($0), 10% of CONE ($9.48/kW-year), 50% of CONE ($47.40/kW-year), and CONE ($94.80/kW-year).

A NPVRR was calculated for each sensitivity in each retirement analysis. A summary of the sensitivities for the analysis is shown in Exhibit A-12, Schedule B6.1 - B6.3, page 2 of 6.

Q45. Why did the Company use four sensitivities for the capacity price inputs in the NPVRR analysis?

A45. It is important to consider a wide range of capacity pricing sensitivities when performing an economic analysis, given the nature of capacity pricing. It is prudent to include these sensitivities in an economic analysis, particularly in light of the recent variability that has been experienced relative to the MISO Zone 7 PRA capacity auction results. For example, the most recent auction clearing price for MISO Zone 7 capacity was $5.00/MW-day ($1.83/kW-year). In contrast, the MISO Zone 7 PRA for plan year 2020/2021 cleared at $257.53/MW-day ($94.00/kW-year), otherwise known as CONE. The auction price of CONE occurred as a result of the Zone 7 MISO planning resources offered in the MISO PRA not meeting Zone 7's LCR. As noted above, this marked the first time that any Zone in MISO has not met its resource adequacy requirements since the beginning of the MISO annual capacity construct in 2013.

Refer to the section of my testimony that discusses the MISO Zone 7 Capacity Position and PRA results for Planning Years 2020/21, 2021/22 as well as the forecasted capacity position for Planning Year 2025/26.

Q46. What are the results of the NPVRR analysis performed for BRPP?

A46. The results of the NPVRR analysis for BRPP show a range of net present value outcomes consistent with the range of capacity prices. A net positive difference indicates that the NPVRR associated with operating the BRPP through the later retirement date is more costly to customers; conversely, a net negative difference indicates that the NPVRR of operating the plant through the later retirement date is less costly to customers. The results of the analysis are summarized in Table 6 below and shown in Exhibit A-12, Schedule B6.1-B6.3, page 2 of 6. Column (b) presents the range of capacity price sensitivities and column (c) presents the range of results.

Table 6: Results of BRPP NPVRR

Belle River Sensitivity	Retirement 2026 VS Retirement 2023 Case	Retirement 2028 VS Retirement 2023 Case	Retirement 2030 VS Retirement 2023 Case
*# $ millions of NPVRR **			
1 Capacity Price at $0 Forecast	89	205	357
2 Capacity Price at 10% of CONE	60	159	296
3 Capacity Price at 50% of CONE	(58)	(26)	53
4 Capacity Price at 100% of CONE	(205)	(256)	(250)

Note: Net negative values imply less costly option for customers; Net positive values imply more costly for customers

A more detailed NPVRR summary for each capacity price sensitivity can be found in Exhibit A-12, Schedules B6.1-B6.3, pages 3-6 of 6.

Q47. What factors has the Company taken into consideration in its decision-making process regarding the timing of the retirement of BRPP?

A47. An NPVRR, or economic cost and benefit analysis, can provide a general guideline for the reasonableness and prudency of continued operations of a generating unit, but there are other factors that need to be considered. As Company Witness Morren indicates in his direct testimony, other factors, such as resource adequacy and grid reliability, need to be understood when determining retirement dates, in addition to economics. He also discusses the Company's decision to cease burning coal at BRPP in 2028.

Q48. Does this complete your direct testimony?

A48. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

BENJAMIN J.H. BURNS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF BENJAMIN J.H. BURNS

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. Benjamin J.H. Burns (he/him/his), Director Marketing, One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Electric Company ("DTE" or "the Company").

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company.

Q3. What is your education background?

A3. I hold an MBA from Columbia Business School. I also hold a Bachelor of Arts in English and Political Science from the University of Michigan.

Q4. What work experience do you have?

A4. I served as a Combat Engineer Officer in the United States Marine Corps on active duty from 2002 to 2006, deploying in support of Operation Iraqi Freedom in 2004. I held three roles of increasing responsibility as Platoon Commander, Company Executive Officer and Battalion Assistant Operations Officer. I left active duty as a Captain.

I worked for Turner Construction Company in project management overseeing high-rise construction in New York, NY from 2006 to 2008. Immediately prior to joining the Company, I was a management consultant with Booz & Company's Engineered Products and Services practice. During my years with Booz (2010 – 2013) I led and worked on projects for Fortune 500 and Private Equity clients that focused on growth strategy and operations improvement.

I joined DTE in 2013 as a Manager in the Corporate Strategy group. In this role I led development of DTE's fossil plant re-use strategy. I also led development of Distribution Operations' strategy to improve work management in support of connecting customers and executing the strategic capital budget. In 2016, I transitioned from that role to serve as Manager of Scheduling and Coordination in Distribution Operations where I led the organization responsible for developing the execution plan for the annual capital work. In 2018, I became the General Manager of the Home Protection Plus business within DTE Gas, which is an appliance repair business offered to customers under Value Added Programs and Services ("VAPS") with approximately 220,000 customers. In 2019, I was promoted to my current role as Director of Electric Marketing and Electrification.

Q5. Please describe your current position and duties.

A5. As the Director of Electric Marketing and Electrification, I lead the organization which serves three primary roles:

1. Transportation Electrification: Accelerate the adoption of electric vehicles across all segments of transportation within our service territory.
2. Customer Marketing: Communicate with external customers regarding rates for both electric service prices and various rate tariffs the Company offers customers for service and address all inbound customer inquiries or complaints.
3. New Product Development: Assess and bring to market programs and services under the VAPS regulations, which support both customer satisfaction and customer affordability.

Purpose of Testimony

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to explain and provide support (including where appropriate, the relevant costs) for the seven following areas:

1. Expenditure status for the already-existing pilots Charging Forward and Charging Forward eFleets;
2. Expansion of DTE's electric vehicle ("EV") pilot, Charging Forward and the associated costs;
3. The introduction of a Residential Batteries pilot and the associated costs;
4. A request to increase merchant fees expense;
5. Certain expenditures related to the Advanced Customer Pricing Pilot ("ACPP") regulatory asset;
6. The 2023 full Time-of-Use ("TOU") roll out outreach and associated costs; and
7. The Electric Regulated Marketing operations and maintenance ("O&M") expense.

Q7. Are you sponsoring any exhibits in this proceeding?

A7. Yes; I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.9	Charging Forward Cost Projections
A-12	B5.9.1	Charging Forward eFleets Pilot Requirements
A-12	B5.9.2	Charging Forward Expansion Pilot Requirements
A-12	B5.9.3	Charging Forward Expansion Letters of Support
A-12	B5.10	Residential Batteries Cost Projections
A-12	B5.10.1	Residential Batteries Pilot Requirements

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A-13	C5.7.1	Customer Service - Credit and Debit Merchant Fees
A-13	C5.9	Regulated Marketing Projected O&M Expense
A-13	C5.9.2	Advanced Customer Pricing Pilot & Time of Use Deferrals
A-29	T1	Charging Forward 2nd Annual Status Report

Q8. Were these exhibits prepared by you or under your direction?

A8. Exhibit A-29, Schedule T1 (Charging Forward 2nd Annual Status Report) was prepared under my direction pursuant to the Orders dated May 2, 2019 and May 8, 2020 in Case Nos. U-20162 and U-20561. Exhibit A-12, Schedule B5.9.3 is expressions of support from external stakeholders. Exhibit A-13, Schedule C5.9.2 is co-sponsored with Witnesses Pizzuti and Sparks. The remaining exhibits were prepared under my direction in support of the instant case.

1. EXISTING CHARGING FORWARD PILOT EXPENDITURES

Q9. What is the current status of the original Charging Forward pilot?

A9. The Company proposed Charging Forward in Case No. U-20162. In May 2019, the Commission issued an Order in the U-20162 proceeding, approving the Charging Forward program approach with some modifications and recommendations. The Company provided an update on Charging Forward in the subsequent case, Case No. U-20561, and the Commission concluded, *"Consistent with the May 2 [2019] order, the Commission agrees with the ALJ that the regulatory asset and the capital expense should be approved for only the actual and reviewed expenses. Going forward, DTE Electric is authorized to begin the five-year amortization concurrent with review and approval in a rate case in lieu of amortization over five years* *beginning the year after the costs are incurred"* (MPSC Case No. U-20561, Order dated May 8, 2020, pp. 165-166). For a complete status update of Charging Forward and justification for its components' costs discussed below, please reference Exhibit A-29, Schedule T1, Charging Forward 2nd Annual Status Report filed by the Company in June 2021 under Case No. U-20162. The remainder of this portion of my testimony will be focused on outlining the past costs and future cost projections for the pilot.

Q10. What are the Company's total expected costs for Charging Forward?

A10. As stated in the MPSC Case No. U-20162 Order dated May 2, 2019, *"The company proposed the pilot program costs be recovered through capital expenditures, O&M expense, and regulatory asset treatment for proposed rebates. 8 Tr 3579-3581. The Staff, however, recommended deferral of both rebates and O&M costs through the creation of a regulatory asset with amortization over a five-year period. 8 Tr 4056-4057"* (p. 113). The Order continues, *"Overall, the Commission finds that regulatory asset treatment, as proposed by the Staff, is the most reasonable and prudent recovery mechanism"* (p. 115). The total actual and estimated expenditures for the program through the end of 2022 are summarized in Table 1 below.

Table 1. Actual & Estimated Pilot Spend (in thousands) by Component[1]

Program Component	**2019**	**2020**	**2021**	**2022**	**Total**
Direct Current Fast Charger Trials	$62	$51	$250	-	$363
Customer Education & Outreach	$382	$202	$810	$406	$1,800
Residential Smart Charger Support	$48	$121	$309	$770	$1,248
Charging Infrastructure Enablement	$100	$460	$1,911	$6,229	$8,700
Additional Elements	$227	$119	$186	$33	$565
Program Management	$273	$449	$453	$238	$1,413
Total	**$1,092**	**$1,400**	**$3,919**	**$7,676**	**$14,088**

[1] Differences in totals due to rounding

Exhibit A-12, Schedule B5.9, page 2 breaks the costs down into capital and regulatory asset expenditures as shown in Table 2 below.

Table 2. Actual & Estimated Pilot Spend (in thousands) by Type

Type of Spend	**2019**	**2020**	**2021**	**2022**	**Total**
Capital	$64	$0	$339	$1,900	$2,303
Regulatory Asset	$1,028	$1,401	$3,580	$5,776	$11,785
Total	**$1,092**	**$1,401**	**$3,919**	**$7,676**	**$14,088**

The capital costs for Charging Forward include:

- Utility infrastructure to deliver electricity from the DTE distribution system to the meter, which may include cable, conductors, conduit, transformer(s), and the meter ("EV Service Connection"); and
- The DTE Distribution Operations ("DO") engineering support required for pilot implementation.

Exhibit A-12, Schedule B5.9, page 2 shows the above total estimated calendar year expenditures broken down into projected capital expenditures (lines 1 through 6) and regulatory asset costs (lines 7 through 17) for the following periods:

- January 1, 2020 to December 31, 2020 ("historical period") in column (b);
- January 1, 2021 to October 31, 2022 ("bridge period") in column (e); and
- November 1, 2022 to October 31, 2023 ("test period") in column (f).

Total estimated pilot costs for those three periods are $1.4 million, $11.6 million, and $0, respectively, as shown in line 18.

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Q11. What are the costs associated with the Direct Current Fast Charger ("DCFC") Trials?

A11. Three of the Company's DCFC trials initiated in 2018 required or will require additional funding: ChargeD Phase 1, ChargeD Phase 2, and the battery-powered DCFC as detailed in the 2nd Annual Status Report.[2] These DCFC trial costs are outlined in Exhibit A-12, Schedule B5.9, page 2, line 2 (DCFC Trials Service Connection) and line 8 (DCFC Trials Supply Infrastructure). The total actual and estimated expenditures for the historical and bridge periods are $0.1 million and $0.3 million in columns (b) and (e), respectively.

The two cost categories associated with the three DCFC trials include:

- The EV Service Connection described above; and
- The infrastructure necessary to deliver electricity from the meter to the Electric Vehicle Supply Equipment ("EVSE"), which may include an electric panel, cable, and conduit ("EV Supply Infrastructure").

Q12. What are the costs for the Charging Forward Customer Education & Outreach?

A12. The Company has shifted funds within Charging Forward to increase the Customer Education & Outreach total expenditures by approximately $200,000 while remaining within the overall budget as outlined in the 2nd Annual Status Report.[3] Line 13 of Exhibit A-12, Schedule B5.9, page 2 shows the actual and projected

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[2] Exhibit A-29, Schedule T1
[3] Exhibit A-29, Schedule T1

Line No.

costs of $0.2 million for the historical period in column (b) and $1.2 million for the bridge period in column (e).

Q13. What are the costs for Residential Smart Charger Support?

A13. The Company has shifted funds within Charging Forward to decrease the Residential Smart Charger Support total expenditures by approximately $0.5 million as outlined in the 1st Annual Status Report.[4] Line 12 of Exhibit A-12, Schedule B5.9, page 2 shows the actual and projected costs of $0.1 million for the historical period in column (b) and $1.1 million for the bridge period in column (e).

Q14. What types of costs are associated with Charging Infrastructure Enablement?

A14. The projected EV Service Connection costs and EV Supply Infrastructure rebate costs are included in the Charging Infrastructure Enablement component for three different categories of EVSE: DCFC infrastructure, Level 2 infrastructure, and fleet charging infrastructure.

The projected expenditures for the Charging Infrastructure Enablement component are shown in Exhibit A-12, Schedule B5.9, page 2 as outlined in Table 3 below.

Table 3. Actual and Projected Costs for Charging Infrastructure Enablement (in thousands)

EVSE Category	**Historical Period** Column (b)	**Bridge Period** Column (e)
DCFC (lines 3 and 9)	$130	$3,870
Level 2 (lines 4 and 10)	$283	$2,100
Fleet (lines 5 and 11)	$48	$2,170

[4] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CFtGtAAL

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Total	**$461**	**$8,140**

Q15. What costs are included with Additional Elements?

A15. The Company expanded the scope of Charging Forward to include three additional elements based upon feedback from its stakeholder discussions:[5]

- An updated EV-Grid Impact Study;[6]
- An EV-Ready Builder Rebate Pilot (as proposed in Case No. U-20561); and
- An EV-Only Off-Peak Incentive Pilot ("Bring Your Own Charger").

Line 14 of Exhibit A-12, Schedule B5.9, page 2 shows the actual and projected costs of $0.1 million and $0.2 million for the historical and bridge periods in columns (b) and (e), respectively.

Q16. What costs are included with Program Management?

A16. The Program Management component includes EV Team Labor and Program Costs. The EV Team includes a manager, principal marketing specialist, and strategist to oversee the overall implementation and execution of the Charging Forward pilot. Program Costs include the web-based application subscription from PowerClerk, EV charger data collection tools, and industry conference expenses to ensure the EV team is implementing best practices from across the nation. These expenditures are shown in Exhibit A-12, Schedule B5.9, page 2, lines 15 and 16 with actual and projected costs of $0.4 million and $0.7 million for the historical and bridge periods in columns (b) and (e), respectively.

[5] Detailed further in the 2nd Annual Status Report (Exhibit A-29, Schedule T1)
[6] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CFdYoAAL

Q17. What is the current status of Charging Forward eFleets ("eFleets")?

A17. To build on momentum of the fleet element of Charging Forward and avoid any gaps in available funding to support fleet electrification, DTE proposed eFleets in an ex-parte filing in December 2020 and received approval in March 2021. Per the Order, *"the Commission concludes that DTE Electric's Phase Two proposal is reasonable and in the public interest as it will develop a better understanding regarding how C&I customers are incentivized to make the transition to clean EV technology, how the increased electrical load associated with EVs impact electrical system usage and grid requirements, as well as the expected operational impacts of a wider commercial EV rollout"* (MPSC Case No. U-20935, Order dated March 19, 2021, pp. 4-5).

eFleets was approved with three primary components: Education & Outreach, Advisory Services, and Charging Infrastructure Enablement for commercial fleets. The transportation segments of focus for the eFleets pilot include mass transit buses, school buses, commercial fleets (including light-, medium-, and heavy-duty vehicles), and off-road vehicles. The Company initiated the Education & Outreach component of eFleets in May 2021 and launched the full pilot in October 2021.

Q18. Does this eFleets proposal meet the pilot definition and corresponding six objective criteria as defined in Order U-20645?

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A18. Yes; Order U-20645 defines a pilot as a limited duration experiment to determine the impact of a measure on one or more outcomes of interest. It also lists the six objective criteria of a pilot as 1) need and goals, 2) design and evaluation, 3) costs, 4) timeline, 5) stakeholder engagement, and 6) public interest. Please see Exhibit A-12, Schedule B5.9.1 for a high-level summary of how eFleets is meeting these requirements and the corresponding questions in this testimony that relate to each of the six objective criteria.

Q19. What are the Company's total expected costs for eFleets?

A19. Per Order U-20935, *"the Commission authorizes DTE Electric to create a regulatory asset, not to exceed $10.3 million, to recognize deferred Phase Two program costs with the amortization of those costs over five years beginning the year after the costs are incurred… In addition, the Commission reiterates that… approval in this case does not signal future authorization of the projected $3.1 million in capital costs… Rather, the company will also be required to present those costs for a future reasonableness-and-prudence review in a future general rate case"* (p.5). For more details on the pilot components and justification for its costs, please refer to the 2nd Annual Status Report.[7] Consistent with the costs identified in the Case No. U-20935 Order, the Company continues to expect that complete implementation of eFleets will cost approximately $13.4 million through the end of 2025 as shown in Table 4 below.

[7] Exhibit A-29, Schedule T1

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Table 4. Estimated Annual Spend for eFleets (in millions)

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Capital	$0	$0.9	$0.7	$0.7	$0.8	$3.1
Regulatory Asset	$0.3	$3.2	$2.1	$2.3	$2.4	$10.3
Total	**$0.3**	**$4.1**	**$2.8**	**$3.0**	**$3.2**	**$13.4**

Exhibit A-12, Schedule B5.9, page 3 details the total estimated expenditures for eFleets broken down into projected capital expenditures (lines 1 through 10) and regulatory asset costs (lines 11 through 22) for the bridge period in column (e) and the test period in column (f). Total estimated eFleets spend for the bridge and test periods are $3.8 million and $3.1 million, respectively, as shown in line 23.

Q20. What are the costs of Customer Education & Outreach for eFleets?

A20. There are no modifications to the Company's eFleets Customer Education & Outreach total expenditures as outlined in the 2nd Annual Status Report.[8] Line 19 of Exhibit A-12, Schedule B5.9, page 3 shows the projected costs of $0.4 million for the bridge period in column (e) and $0.3 million for the test period in column (f).

Q21. What are the costs for Fleet Advisory Services?

A21. There are no modifications to the Company's eFleets Advisory Services total expenditures as outlined in the 2nd Annual Status Report.[9] This component includes costs for conducting customized fleet electrification studies for commercial and industrial ("C&I") customers, the web-based application subscription from PowerClerk, EV charger data collection tools, and any expenses for the eFleet EV Team to participate in conferences for sharing best practices across the nation. Line

[8] Exhibit A-29, Schedule T1
[9] Exhibit A-29, Schedule T1

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21 of Exhibit A-12, Schedule B5.9, page 3 shows the projected costs of $0.4 million for the bridge period in column (e) and $0.3 million for the test period in column (f).

Q22. What types of costs are included in Charging Infrastructure Enablement for eFleets?

A22. The projected EV Service Connection costs and EV Supply Infrastructure rebate costs are included in the Charging Infrastructure Enablement component for two different categories of infrastructure, Level 2 and DCFC, for the five different transportation segments described above. The projected expenditures for the Charging Infrastructure Enablement component are shown in Exhibit A-12, Schedule B5.9, page 3 as outlined in Table 5 below.

Table 5. Projected Costs for eFleets Charging Infrastructure Enablement (in thousands)

Program Component	**Bridge Period** Column (e)	**Test Period** Column (f)
DCFC Infrastructure (lines 2-5 and 12-15)	$1,476	$1,365
Level 2 Infrastructure (lines 6-8 and 16-18)	$886	$693
Total	**$2,362**	**$2,058**

Q23. What costs are included in Program Management for eFleets?

A23. The Program Management component includes the costs for the eFleets EV Team and DO Engineering Labor. The eFleets EV Team includes shared resources with the original Charging Forward pilot, including a manager, principal marketing specialist, strategist, and a corporate communications specialist to oversee the overall pilot implementation. In addition, a sales team comprised of a manager, a

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senior sales specialist, and a sales associate will support execution of eFleets across the five transportation segments described above. DO Engineering Labor costs include labor hours from various colleagues in the DO team supporting the eFleets EV Team and is tracked separately from other DO Engineering work (to not be double counted). These expenditures are shown in lines 9 and 20 of Exhibit A-12, Schedule B5.9, page 3 in columns (e) and (f) with projected costs of $0.7 million and $0.4 million for the for the bridge and test periods, respectively.

Q24. How does the Company propose to continue reporting for Charging Forward and eFleets going forward?

A24. The Company will continue to file quarterly reports as well as Annual Status Reports in case docket U-20162. Additionally, DTE will continue to host stakeholder discussions approximately twice per year.

2. CHARGING FORWARD EXPANSION

Q25. What are the elements of the Charging Forward Expansion ("Expansion") proposal?

A25. DTE is proposing the extension of the following existing elements with modifications based on lessons learned and described in more detail below: Customer Education & Outreach, Residential Smart Charger Support ("Residential Rebates"), Bring Your Own Charger, EV-Ready Builder Rebates, and Charging Infrastructure Enablement ("Make-Ready Rebates"). Additionally, DTE is proposing the introduction of the following new elements to address identified gaps described in more detail below: Residential Charging as a Service ("CaaS"), Charging Hubs, Transit Batteries, Transportation Network Company ("TNC")

Driver Rebates, Income-Eligible Rebates, Commercial CaaS, and an Emerging Technology Fund.

Q26. Does this Expansion proposal meet the pilot definition and corresponding six objective criteria as defined in Order U-20645?

A26. Yes; similar to Charging Forward eFleets, please see Exhibit A-12 Schedule B5.9.2 for a high-level summary of how the Charging Forward Expansion is meeting these requirements and the corresponding questions in this testimony that relate to each of the six objective criteria.

Q27. How is the Charging Forward Expansion portion of your testimony structured?

A27. The Charging Forward Expansion testimony is organized in four sections:

I. Transportation Electrification ("TE") Market Overview;
II. DTE's Role in TE;
III. Charging Forward Expansion Pilot Design; and
IV. Cost-Benefit Analysis.

I. TE Market Overview

Q28. How do you define an EV?

A28. For the purposes of this testimony, EVs include on-road battery EVs ("BEVs")[10] and plug-in hybrid EVs ("PHEVs").[11]

Q29. What are the different types of EVSE available?

[10] Battery Electric Vehicles (BEVs) use only electricity stored in a battery pack to power an electric motor.
[11] PHEVs are like BEVs but also have an internal combustion engine fueled by gasoline that can be used.

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A29. EVSEs fall into three different levels of charging power:

- Level 1 is the lowest level of charging at 120 volts ("V") and is typically a standard outlet, delivering around 3-5 miles of charging in an hour;
- Level 2 is 240V (similar to an electric oven or dryer) and charges a vehicle between 12-60 miles in an hour depending on the power of the charger; and
- Level 3 (commonly known as DCFC) requires a minimum of 480V and can charge 80% of a vehicle's battery in as little as 30 minutes (160+ miles in an hour depending on the power of the charger).

EVSE is also either networked or non-networked. Networked EVSE requires either a cellular or wireless connection to communicate over the air (which allows for payment collection, data storage, and remote software updates among other things). Network Providers typically require a software licensing fee from the owner of the EVSE for those capabilities to be utilized. Non-networked EVSE does not have the ability to communicate, and there are no ongoing software costs for the owner.

Q30. What are the current market dynamics for EVs?

A30. Recent announcements by major automakers show that the future of mobility is electric. In the first two months of this year, four major automakers announced new goals to phase out sales of internal combustion engine vehicles, driven primarily by tightening restrictions in Europe.[12] Automakers have been announcing increased investment in EVs for years, and these models are finally entering the market. For example, the number of EV models produced in North American plants is expected to increase from 49 today to over 100 by 2024.[13] EVs are not only increasing in

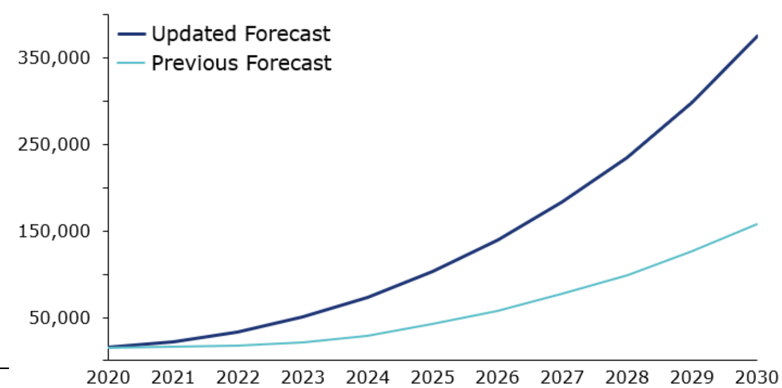
[12] Bloomberg New Energy Finance ("BNEF") Electric Vehicle Outlook 2021
[13] Automotive Communities Partnership June 2021 Webinar

model availability but also becoming more affordable. Battery prices have declined 64% over the last five years, and they are expected to decrease another 25% by 2025.[14]

Q31. What are the current and future adoption rates for EVs in Michigan?

A31. As of August 2021, there were almost 28,000 EVs in Michigan, or about 0.4% of total vehicles on the road. Of those, approximately 68% (19,000) are in the Company's electric service territory.[15] While the market is relatively small today, industry experts expect that to change rapidly over the coming years. Despite global passenger vehicle sales falling 13% overall in 2020 due to the pandemic, EV sales increased 48%.[16] Michigan has also experienced record-level EV sales recently, from an average of 260 EVs sold per month in 2019 and 2020 to over 1,000 EVs sold per month over the last six months of available data (March-August 2021). Based on this and other upwards-adjusted industry expert forecasts,[17] DTE recently updated its forecast and now projects that 11% (375,000) of vehicles on the road in its electric service territory will be EVs by 2030, as shown in Figure 1 below.

Figure 1. Cumulative EV Sales Forecast in DTE's Territory by 2030



[14] BNEF, McKinsey
[15] IHS Markit
[16] BNEF Electric Vehicle Outlook 2021
[17] BNEF (national), Automotive Communities Partnership (national), and IHS Markit (Michigan) forecasts

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Q32. Do you anticipate benefits from TE?

A32. Yes; TE benefits many stakeholders. First, electric customers benefit through downward rate pressure, because EV load is relatively flexible and can be shifted to times when there is more available capacity on the grid, effectively spreading system fixed costs over increased sales. Second, EV owners experience total cost of ownership savings through approximately 50-60% lower fuel and maintenance costs than a gasoline vehicle.[18] Third, the public at large benefits from environmental benefits, since EVs emit 55% less greenhouse gases ("GHGs") than a traditional gasoline vehicle in Michigan annually.[19] The transportation sector in Michigan currently accounts for 33% of emissions in the state, and as the Company's generation portfolio moves towards net zero, electrifying vehicles will be critical for the State of Michigan to meet its own net zero target by 2050.[20,21] Finally, TE can be an important piece of economic development for Michigan as the automakers in the state shift toward EVs, creating new opportunities for battery and vehicle engineering and manufacturing.

Q33. Do barriers remain to EV adoption that could dampen adoption rates and realization of the associated benefits?

A33. Yes; the speed of EV adoption lags behind that of other new technologies after their introduction for several key reasons, including: lack of awareness and familiarity with EVs, a perceived lack of available EVSE ("range anxiety"), upfront EV price

[18] Consumer Reports – Electric Vehicle Ownership Costs (October 2020)
[19] https://afdc.energy.gov/vehicles/electric_emissions.html
[20] https://www.eia.gov/environment/emissions/state/ (Table 4)
[21] https://www.michigan.gov/whitmer/0,9309,7-387-90499_90704-540278--,00.html

premiums, and the burdensome home charger installation process. These key barriers to EV adoption will each be addressed in more detail below.

<u>DTE's Role in TE</u>

Q34. What are the key roles for utility involvement in TE?

A34. The Commission established objectives for utilities in the TE space as follows: *"(1) maximize program participation at minimum cost; (2) aggressively test new and novel practices and technologies to ensure that new load associated with EV charging maximizes net benefits to all ratepayers; and (3) ensure that investments in make-ready infrastructure serve double duty by directly addressing core barriers (such as range anxiety), and by enabling the company to learn reasonable and practicable ways to actively manage charging times and locations, to minimize required investment in new distribution infrastructure, and to obviate adverse grid impacts related to uncontrolled charging*" (MPSC Case No. U-20162, Order dated May 2, 2019, p. 113). Playing a proactive role and learning now – while EV adoption remains relatively low – is important for a utility to ensure that widespread EV adoption in the future is integrated efficiently with the grid to maximize net benefits to its customers.

Additionally, utilities still have a critical role to play in reducing barriers to EV adoption, especially as it relates to a lack of awareness of EVs and range anxiety. The Critical Consumer Issues Forum ("CCIF") aims to facilitate exchanges among state commissions, consumer advocates, and electric companies and highlight areas of agreement in a way that enhances each group's individual efforts to address important consumer-focused issues. Per the CCIF in July 2019, *"Customer*

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education should be considered as an important component of electric company electric transportation-related programs" and *"Multiple entities, including electric companies, need to be involved in meeting electric transportation infrastructure and deployment needs."*[22]

Finally, enabling equitable access to EVs is important, and a utility is well-suited to address this gap. Another consensus statement from the CCIF states, *"electric companies may invest in areas where third-party service providers are not investing. With a history of serving all communities in their service areas, as well as having access to lower-cost capital, electric companies are well-suited for helping ensure access to low- to moderate-income and underserved populations."*[23]

Q35. What are DTE's guiding principles for the Expansion pilot's design?

A35. DTE's overarching guiding principle is to play a proactive role in testing various incentive structures and ownership models now to better understand how EV load can best be added to the system in the future to maximize net benefits to its customers. To that end, DTE uses the key roles of utility involvement for TE described above and summarized here as its guiding principles:

1) Reduce barriers to EV adoption;
2) Efficiently integrate EV load with the grid;
3) Help enable equitable access to EVs; and
4) Test new technologies to prepare for widespread TE adoption in the future.

[22] http://www.criticalconsumerissuesforum.com/wp-content/uploads/2019/07/CCIF-Electric-Transportation-Report-July-2019.pdf
[23] http://www.criticalconsumerissuesforum.com/wp-content/uploads/2019/07/CCIF-Electric-Transportation-Report-July-2019.pdf

Additionally, a fifth guiding principle DTE uses to inform pilot design is to ensure actions benefit the public interest and State of Michigan. From joint comments filed by DTE and 18 other organizations[24] on November 17, 2017 in Case No. U-18368, *"Transportation Electrification is in the public interest. There is a clear policy case for transportation electrification, as it can offer operational savings to PEV drivers, support local industries in the state, ... and provide significant environmental benefits to all Michigan residents through reduced emissions"* (p. 2).

Q36. Is the Expansion consistent with the expectations of the State of Michigan?

A36. Yes; momentum for TE is building in Michigan. Governor Whitmer created the Michigan Office of Future Mobility and Electrification with Executive Directive 2020-01 on February 25, 2020, stating *"(to) secure Michigan's position as a global leader in the future of mobility, the State must think creatively and act comprehensively…And it must expand Michigan's global leadership in developing the systems and networks necessary for the deployment of connected infrastructure, autonomous technologies, shared transportation, and electric vehicles."*[25]

Additionally, Michigan committed *"to achieve economy-wide carbon neutrality no later than 2050"* with an interim goal *"to achieve a 28% reduction below 2005 levels in greenhouse gas emissions by 2025"* with Executive Directive 2020-10 on

[24] Actia, Advanced Energy Economy, The Alliance for Transportation Electrification, Clean Fuels Michigan, Consumers Energy Company, The Ecology Center, Edison Electric Institute, Ford Motor Company, General Motors, Greenlots, Michigan Electric and Gas Association, Michigan Energy Innovation Business Council, Michigan Environmental Council, Michigan League of Conservation Voters, Natural Resources Defense Council, Phoenix Contact, Siemens, and Sierra Club
[25] https://www.michigan.gov/whitmer/0,9309,7-387-90499_90704-521687--,00.html

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September 23, 2020.[26] The transportation sector is the largest contributor to GHG emissions in the United States ("U.S."), so TE will be an important piece of the solution. With approval of DTE's eFleets pilot, the Commission stated, *"the continued growth of EV adoption and carbon reduction is consistent with Governor Gretchen Whitmer's 'MI Healthy Climate Plan' as announced in Executive Directive 2020-10 and Executive Order 2020-182"* (MPSC Case No. U-20935, Order dated March 19, 2021, p. 4), signaling that DTE's TE efforts are well aligned with State policy.

Q37. What has DTE learned so far with its existing Charging Forward initiative?

A37. The 2nd Annual Status Report for Charging Forward provides a detailed update of the existing pilot.[27] A few of the key lessons learned include:

- Incentives are an effective method to increase TOU enrollment and shift EV load off-peak: 87% of Residential Rebate applicants said the rebate influenced their decision to enroll in a TOU rate, and 88% of charging takes place outside of 3-7 pm (the "critical peak window");
- Creative solutions to incentivize off-peak charging both maximizes participation and benefits all customers: it took about half the time for the Company's Bring Your Own Charger ("BYOC") pilot to reach 400 participants as it did for the Residential Rebate element, and DTE saw a reduction of 21% in critical peak window load from BYOC participants' whole-home usage before and after enrollment; and
- Public charging infrastructure can be efficiently integrated with the grid to minimize distribution upgrade investments: the average waived

[26] https://www.michigan.gov/whitmer/0,9309,7-387-90499_90704-540278--,00.html
[27] Exhibit A-29, Schedule T-1

contribution in aid of construction ("CIAC") costs were $0 per site for Level 2 (average of four ports per site) and only $5,000 per site for DCFCs (average of two chargers per site) for Charging Forward to-date.

Q38. Are there gaps that still need to be addressed?

A38. Yes; after two years of implementing Charging Forward, the Company has identified several gaps that still need to be addressed to better facilitate EV adoption. These gaps (*and the corresponding Charging Forward Expansion elements designed to help address these gaps*) are as follows:

- There is still a significant gap in awareness of EVs: 53% of DTE customers surveyed in November 2020 still could not correctly name an EV model (*Customer Education & Outreach*);[28]
- Range anxiety continues to deter adoption: 63% of customers surveyed state location and availability of charging stations as a primary barrier to purchase (*Customer Education & Outreach, Make-Ready Rebates, and Commercial CaaS*);[29]
- The upfront purchase premium is difficult to overcome: 57% of customers surveyed state the price of an EV is too high (*Transit Batteries, TNC Driver Rebates, Income-Eligible Rebates*);[30]
- The process and cost to install a home charger is burdensome: 48% of customers surveyed did not know how to install a home charger or thought it was difficult, and about half of approved Residential Rebate participants required some sort of electrical upgrade (*Residential CaaS*);[31]

[28] DTE Tracking Survey from November 2020 (n = 503)
[29] DTE Tracking Survey from November 2020 (n = 503)
[30] DTE Tracking Survey from November 2020 (n = 503)
[31] DTE Tracking Survey from November 2020 (n = 503)

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- Expensive, high-powered charging infrastructure required to electrify fleets is a difficult barrier to overcome for already-hesitant fleet operators (*Charging Hubs*);
- The business case to install charging equipment is still very challenging, especially in underserved areas (*Commercial CaaS*); and
- DTE's ability to fund quickly evolving technology pilots is constrained in a regulatory environment (*Emerging Technology Fund*).

Q39. Are there design characteristics that still need to be tested?

A39. Yes; the Company would like to continue testing different design characteristics to analyze corresponding impacts and determine the most appropriate long-term application. Specific design characteristics that DTE still needs to test include, but are not limited to, incentive structures, qualification criteria, and ownership models.

Q40. Why should DTE expand Charging Forward at this time?

A40. It is anticipated that the three-year Charging Forward pilot approved in Case No. U-20162 will have fully utilized its approved funding in the next year, approximately three years after approval in May 2019. The spend is within budget in the expected timeline and achieved its objectives as detailed in the 2nd Annual Status Report.[32] To avoid disruption in utility programming at this critical market stage that furthers State of Michigan policies, a Charging Forward Expansion is required. Management consulting firm Guidehouse states, *"The next few years represent the precipice of a multi-decade transition toward a decarbonized mobility future. U.S. market insights suggest a growing consensus that the better*

[32] See Exhibit A-29, Schedule T1

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stakeholders prepare their EV markets and electric distribution infrastructure to support the transition—through data-driven planning and market interventions—the more cost effective the transition can be for ratepayers."[33]

II. Charging Forward Expansion Pilot Design

Q41. What are the key goals of the Charging Forward Expansion?

A41. Consistent with DTE's role in TE and guiding principles above, the key goals of the Charging Forward Expansion are to reduce barriers to EV adoption, efficiently integrate EV load with the grid, enable equitable access to EVs, pilot new technologies, maximize participation at a minimum cost, and support State of Michigan policy initiatives.

Q42. What are the primary components of the Charging Forward Expansion?

A42. The elements of the Charging Forward Expansion outlined above can be grouped into the following five primary components:

A. Customer Education & Outreach;
B. Residential Level 2 Charging;
C. Commercial Customer Support;
D. Equitable Access to EVs; and
E. Program Development.

The elements within each of the primary components are detailed in the following sections. All of them were designed with DTE's guiding principles in mind as shown in Table 6 below.

[33] "The Emerging Mobility Universe," Guidehouse, October 2021

Table 6. Overview of Expansion Elements by Guiding Principles

Primary Component	Pilot Element	Reduce Barriers	Efficient Integration	Equitable Access	Test New Technologies / Models	Support Michigan
Customer E&O	Customer E&O	x	x	x		x
Residential Level 2 Charging	Residential Rebates	x	x			
	BYOC	x	x			
	EV-Ready Builder Rebates	x	x	x		
	Residential CaaS	x			x	
Commercial Customer Support	Make-Ready Rebates	x	x			x
	Charging Hubs	x	x		x	x
	Transit Battery Leasing	x		x	x	x
Equitable Access	TNC Driver Rebates	x		x	x	
	Income-Eligible Rebates	x		x		
	Commercial CaaS	x		x	x	x
Program Development	New Technology Pilot Fund				x	x
	Program Management	x	x	x	x	x

A. Customer Education & Outreach ("E&O")

Q43. What is a primary barrier to EV adoption?

A43. Lack of awareness of EVs and their associated benefits is still a primary barrier to EV adoption. As stated above, 53% of DTE customers surveyed could not correctly name an EV model.[34] If customers are unaware of EV models or unfamiliar with the technology, they will not even consider an EV for their next vehicle purchase. Another large awareness barrier is that 49% of non-EV owners surveyed know about zero or only one public charging station, despite hundreds available in DTE's service territory.[35] However, once a person owns an EV, 77% of those originally concerned about insufficient range and/or charging infrastructure became less or no

[34] DTE Tracking Survey from November 2020 (n = 503)
[35] DTE Tracking Survey from November 2020 (n = 503)

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longer concerned,[36] indicating that in addition to deploying more charging infrastructure, education is another way to address range anxiety.

Q44. Why should DTE provide education on EVs?

A44. Per the Midcontinent Transportation Electrification Collaborative consensus principles, *"Utilities are a trusted source of information about charging solution choices, have established relationships with their customers, and have the ability to communicate the benefits of EVs to their customers."*[37] Fuel economy is the number one reason why DTE customers are buying EVs,[38] and as the "fuel" provider, DTE is best suited to provide education on the electric pricing options that benefit both EV drivers and DTE's customers. Credible sources suggest that car buyers spend as many as 13 hours researching cars online before even going to the dealer, so typically their minds are already made up.[39] The DTE EV webpages are an important online resource for consumers in the purchase funnel, and they have been viewed over 414,000 times since launch of Charging Forward in May 2019. The Company's EV webpages are also starting to gain traction: more than half of those webpage views have been in the last four months. Additionally, in 2020, 19% of customers reported they would or had visited DTE's website for EV resources compared to 14% the year prior, an increase of 36%.[40] To continue to be a trusted source of information for its customers, its critical to expand Charging Forward's Customer E&O component to continue engaging customers and driving

[36] AAA Electric Vehicle Ownership Survey 2019 (n=1,090)
[37] https://www.betterenergy.org/wp-content/uploads/2018/04/MTEC_White_Paper_April_2018-1-1.pdf
[38] DTE Tracking Survey from November 2020 (n = 503)
[39] California New Car Dealers Association
[40] DTE Tracking Survey from November 2020 (n = 503)

them to the website, which the Company will keep improving based on lessons learned.

Q45. Does E&O affect efficient integration of EV load with the grid?

A45. Yes; E&O is important to improve EV driver understanding of available TOU rates and other managed charging incentives. Managed charging not only saves EV drivers more money on fuel but also benefits DTE customers at large by shifting charging to times that are better for the system overall.

Q46. What practices will DTE continue from its current E&O pilot?

A46. For potential EV drivers, the Company will continue to deploy best practices such as consistent messaging to amplify the benefits of EVs and break down the perceived barriers to adoption via a robust multi-channel campaign. For potential EVSE owners ("site hosts"), DTE will continue the best practice of communicating the benefits of owning and operating EVSE. Overall, E&O will continue to support customers' electrification journeys by making them aware of available incentives, electric pricing options, electrician resources, charger locations, DTE's EV community ("EV Connections"), and DTE EV webpages (including its Virtual EV Showroom).

Q47. How will E&O for the Expansion be different than the current offering?

A47. Once safe to do so, DTE will ramp up in-person EV experiences, which it has not been able to do for the majority of Charging Forward thus far due to the pandemic. Based on post-rebate survey feedback, DTE also plans to add EV capability to an enterprise-wide rate tool to guide potential and current EV drivers to the best TOU rate for them. Additionally, the Company would like to explore how to further strengthen the customer experience for its already-popular Virtual EV Showroom tool, potentially directly connecting to dealership inventory. The Company is requesting $1.5 million for Customer E&O, including the development of an EV-specific rate selection tool for customers.

Q48. What metrics will the Company use to gauge success of the E&O component?

A48. The Company will continue to evaluate the success of its E&O efforts using both quantitative and qualitative measures. Metrics such as impressions, tactics, website views, and survey data provide a quantitative update on the progress, while customer verbatims from surveys deliver qualitative insight.

B. Residential Level 2 Charging

Q49. What incentives does DTE currently offer through Charging Forward to support Residential Level 2 Charging?

A49. DTE currently offers three incentives to support Residential Level 2 Charging:

- Residential Rebates: a $500 rebate to customers that have an EV, install a qualified Level 2 charger, and enroll in a TOU rate;
- BYOC: payments up to $24/quarter for EV drivers that have a Level 2 charger and are on the regular residential rate (D1) but comply with BYOC's off-peak charging requirements;[41]
- EV-Ready Builder Rebate: up to a $250 rebate for builders to future-proof new construction single-family and multi-family homes with the wiring for Level 2 chargers.

[41] BYOC is administered by Sagewell, using its software analytics on participant meter data

Additionally, DTE's Demand Response ("DR") team manages DTE Smart Charge, which utilizes vehicle telematics in partnership with Ford and General Motors ("GM") to incentivize drivers to temporarily pause or start their vehicle's charging when it is most beneficial to the system.[42]

Q50. What are the key learnings from those existing incentives so far?

A50. For Residential Rebates and BYOC, there have been a few key learnings so far. First, 87% of applicants cited the Residential Rebate as influencing their enrollment in a TOU rate, giving the Company a clear indication that a large group of customers opt to remain on the regular residential rate without an incentive to switch.[43] Second, TOU rates and compliance incentives are an effective way to shift load off-peak: BYOC and Residential Rebate participants reduced critical peak window charging by 67% and 48%, respectively, compared to customers on the regular residential rate. Both of these learnings give credence to the theory that the Company's incentives are necessary to promote off-peak charging and produce benefits for its customers.[44]

For EV-Ready Builder Rebates, DTE has learned that these are not as attractive as anticipated for builders for two reasons:

1. Single-family builders want to keep offerings to customers consistent across homes and communities and, given the short-term nature of Charging

[42] For additional information on DTE Smart Charge, please see testimony of Witness Farrell
[43] DTE Tracking Survey from November 2020 (n = 503)
[44] BYOC and regular residential rate data from Sagewell; Residential Rebate data from chargers

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Forward, the builders are hesitant to start putting in the wiring without knowing if rebates will be available in out-years; and

2. Multi-unit dwelling ("MUD") builders are not always able to install 50-amp wiring for apartment complexes with smaller panels.

Q51. What is the expected impact of continuing to offer the Charging Forward Residential Rebate?

A51. To efficiently integrate EV load with the grid and maximize net benefits to customers, it is imperative that home charging takes place off-peak when the grid has more available capacity. Managed charging incentives have proven to effectively change the charging habits of EV owners, since those that do participate in managed charging incentives charge more off-peak than those that do not. Furthermore, 62% of Residential Rebate participants opted for a whole-home TOU rate to qualify for the rebate, which likely shifted even more of their total load off-peak than just EV load, further benefiting the system. The Company is requesting $0.4 million to support this element, which will allow up to 800 customers to participate through the test period.

Q52. Does DTE propose any modifications to the Residential Rebate offering?

A52. Yes; DTE proposes to continue to offer the $500 rebate but to remove the list of qualified chargers and allow customers to install a Level 2 charger of their choice.

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Q53. Why does DTE believe this modification will be beneficial to the Expansion's goals?

A53. Despite Charging Forward proving effective with the participants it does have, uptake in the incentives has been somewhat limited: there have been approximately 6,250 EVs sold in DTE's service territory since Charging Forward launched, but there are only 1,050 total Residential Rebate and BYOC participants so far. DTE is seeking to improve uptake with the Expansion by adjusting eligibility requirements for the Residential Rebates. Allowing the Company to test the new qualifications and compare against the original incentive and early success of BYOC will help determine the best long-term approach. While it is beneficial for DTE to receive data from the currently qualified chargers, the Company does not see that as a requirement going forward for two reasons. First, DTE estimates that over 2,000 networked chargers will be enrolled in the existing Charging Forward pilot, and it can leverage the advanced metering infrastructure ("AMI") analytics from Sagewell and the EV-only TOU rate (D1.9) if a larger sample of customers is needed. Second, removing the qualified charger requirement will help to keep costs lower for customers as they will be able to choose less expensive chargers and/or potentially not have ongoing software fees.

The Company recognizes the long-term benefits of networked chargers as more distributed energy resources ("DERs") are added to the grid, but given the relatively small size of the pilot and the somewhat random locations they would be placed as customers participate, the value of the network capability will likely not be realized by the Company or its customers in the next five years. Additionally, future DR pilots and programs do not only have to rely on networked chargers – they can also

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be achieved by controlling charging through vehicle telematics, as demonstrated by DTE Smart Charge.

Q54. Why is it important to continue offering BYOC in parallel?

A54. One of the primary goals of Charging Forward is to maximize program participation at a minimum cost. By offering BYOC, DTE increased Charging Forward participants from 615 to 1,050 at a relatively low cost within one year. The Company is still testing the best way to incentivize customers to charge their vehicles off-peak, and 22% of BYOC participants indicated they did not want to enroll in a TOU rate.[45] If customers do not feel comfortable moving their entire home onto a TOU rate, nor do they want to pay for the installation of a second meter, BYOC is an efficient, effective way to incentivize off-peak charging in the near-term and ensure EV load benefits accrue to all customers. The Company is requesting $0.1 million for this element, which can support adding up to an additional 500 participants through the test period.

Q55. Why should the EV-Ready Builder Rebate be continued?

A55. It can cost up to five times as much to install the wiring for an EV charger after a home is built. However, absent a rebate, builders are largely not offering EV future-proofing to their customers. Incentivizing both single-family and MUD builders to install this wiring upfront will make it easier and less expensive for future residents to purchase an EV. If Michigan building codes are updated to require EV-readiness for new building construction, the Company would discontinue the EV-Ready Builder Rebate and only distribute funds to previously-approved communities. The

[45] BYOC participant survey April 2021 (n=105)

Company is requesting $0.1 million for this element, which can support the wiring for up to 280 homes through the test period.

Q56. Does DTE want to introduce another element in the Charing Forward Expansion to encourage Residential Level 2 Charging?

A56. Yes; the Company is proposing to offer Residential CaaS to alleviate the burdensome process and upfront costs of installing home chargers.

Q57. What are the primary design features of Residential CaaS?

A57. DTE will offer a turnkey installation and financing solution to customers interested in a Level 2 charger for their single-family homes. The Company will contract with licensed electricians to install a 240V outlet in customer homes, and it will also contract with charging vendors to provide a plug-in EV charger if the customer opts for a full charging solution (versus just the 240V outlet). Once the installation is complete, the customer would pay a monthly fee on their electric bill for a period of ten years. The Company is requesting $2.4 million to support this element, which will allow up to approximately 1,100 customers to participate through the test period.

Q58. What value does this service add for the participating customer?

A58. The typical home charger installation process requires as many as seven steps (with EV customers having to undertake research at most steps along the way). DTE's home charger installation service would reduce the number of steps for participating customers to only two: contact DTE and schedule the installation. Customers will no longer need to worry about finding available incentives, researching chargers, vetting electricians, or soliciting quotes, which will reduce the amount of time, complexity, and frustration for them.

Additionally, this service will partially or fully remove the upfront cost for customers to install an EV charger, which is about $2,000 on average today.[46] Spreading the upfront cost over ten years in the form of an affordable monthly payment on the customer's electric bill – which should be less than what they are saving in monthly fuel costs – assists in removing both complexity and upfront price pressure when purchasing an EV.

Q59. Is Residential CaaS designed to be participant-funded?

A59. Yes; the monthly fee over a period of ten years would be designed to cover the increased revenue requirement from the capital outlay and estimated maintenance costs, ensuring that impact on rate base is neutral over time. If customers move before the ten years is complete, the unpaid amount left on their agreement will be added to their final electric bill (along with any unpaid usage fees from their meter). For instance, if a customer has paid a total of $800 of principal towards their $2,000 installation, they will have the remaining principal of $1,200 added to their final electric bill. The customers that opt for the full charging solution will be able to take the plug-in chargers with them, and the home will be EV-ready with the 240V outlet for the next resident.

[46] PlugShare EV Home Charging Station Installation in the US Survey (n=3,500); Residential CaaS is meant to finance the cost of a standard installation - there may be cases where customers need to pay some amount upfront if their installation requires significant additional services (e.g., upgraded service, new panel, wiring through finished drywall, etc.)

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Q60. What are the key learnings DTE is seeking from this new service?

A60. DTE is seeking to understand three key things from Residential CaaS. First, it is seeking to understand how the burdensome process to install a Level 2 charger at home is impacting EV adoption. While on the surface it may not seem like a critical factor, it could be enough to dissuade a large portion of customers on the fence when considered in conjunction with other barriers (e.g., the upfront premium of EVs and the lack of familiarity with the technology and/or installation process). Understanding customer demand for an offering like this to simplify the EV charger installation process and finance it on a customer's monthly bill will be important information for future pilots and programs.

Second, DTE is seeking to strengthen partnership opportunities with dealerships. As reported in its 1st Annual Status Report, the Charging Forward team visited over 30 dealerships of 10 different automakers, presented an overview of the EV market and available program incentives to ~120 participating dealership personnel at the Michigan Automobile Dealers Association annual conference, and hosted a Lunch and Learn at the Detroit Auto Dealers Association in 2019. The team educated salespeople on Charging Forward incentives, electric pricing options, and DTE EV website resources and provided leave-behind materials for both the sales staff and potential EV buyers.[47] Offering an easy solution for home charging to potential EV buyers could help dealership personnel with sales, and increased sales will help them become more familiar with the technology to field questions as needed.

[47] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CFtGtAAL

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Third, the Company would like to understand the best way to encourage participants to charge off-peak. Since this element of the Expansion is designed to be participant-funded and is seeking to understand how large of a barrier home charger installation is for potential EV buyers, DTE does not want to introduce a TOU requirement as a potential limiting factor to start. However, the Company does intend to promote its available managed charging incentives to these customers and better understand what new drivers will decide to do (and why).

Q61. How is this complementary to other Charging Forward elements?

A61. Residential CaaS is complementary to the existing Residential Rebate and BYOC elements, which can be coupled with this offering to incentivize off-peak charging.

Q62. What metrics will the Company use to evaluate the Residential Level 2 Charging component?

A62. The Company will track several metrics to gauge success of the Residential Level 2 Charging component, including:

- Number of participants by element;
- Participant enrollment in managed charging incentives (if applicable);
- Charging behavior (percent off-peak vs. on-peak); and
- Installation and maintenance costs.

C. Commercial Customer Support

Q63. What incentives does DTE currently offer through Charging Forward to support commercial customers?

A63. DTE currently offers Make-Ready Rebates to commercial customers that install and operate qualified Level 2 chargers and/or DCFCs. In both cases, if an EV Service Connection is required, DTE fully funds the DTE-owned equipment up to $100,000 per site. For the Level 2 chargers, there is an additional $2,500 rebate per port installed. For DCFCs, there is a tiered rebate structure based on the power output of the charger; rebates start at $18,000 for 50 kilowatts ("kW") and go up to $55,000 for 150kW or higher. As of November 2021, Charging Forward is fully subscribed for both Level 2 and DCFC rebates.

Q64. What are the key learnings from the Make-Ready Rebates so far?

A64. There have been several learnings that DTE has gained from the Make-Ready Rebates since pilot launch. From a cost standpoint, the Company has learned it can efficiently integrate DCFCs with the grid through an engineering assessment process. The Company first evaluates if a system upgrade is required prior to application approval and institutes an "On-Hold" process for sites that require significant investment. In doing so, the Company identified installations for 16 chargers that would have required significant EV Service Connections (in excess of $100,000 per site) and successfully influenced the relocation of 25% of them to better sites (while the others were withdrawn). Also, by following that process, the waived CIAC fees have only cost approximately $5,000 to install two DCFCs at a site on average (versus an original estimate of $40,000 per site). Because of its proactive engineering assessment process, the Company was able to nearly triple the number of DCFC rebates offered to customers from 32 to 90 with the same amount of funding, achieving its objective to maximize participation at a minimum cost to customers. For Level 2 chargers, no sites to-date have required any CIAC fees as existing electrical infrastructure has been sufficient to power the chargers.

DTE has also learned the importance of designing rebates to incentivize the types of chargers deployed. For example, the Company was unintentionally only incentivizing 50kW chargers with its original $20,000 per charger rebate but has since adjusted to the tiered rebate structure described above after feedback from stakeholders, which more fairly incentivizes higher-powered charging deployment. The Company has also learned the importance of its incentives for charging infrastructure deployment at this nascent market stage. DTE has rejected several DCFC applications due to location or grid impact, and none of the site hosts have proceeded to install DCFCs absent the Charging Forward rebate. Additionally, DTE surveyed 20 customers that are currently on a DCFC waitlist (since the existing rebates are nearly fully subscribed), and 100% of respondents indicated they do not plan to move forward without a rebate.

The Company has also learned from Charging Forward data that approximately 75% of commercial charging takes place outside the critical peak window, so it does believe this added load can be beneficial to all customers so long as it is correctly managed at the local distribution level and during critical peak events. Lastly, the Company confirmed its hypothesis that DCFC site hosts would most likely enroll in its General Service Rate (D3), which does not require a demand charge but has a volumetric charge that is three to four times greater than those that do (e.g., D4 and D11). To-date, five site hosts are served by D3 whereas three site hosts opted to include the DCFCs on their existing rates with demand charges. Of

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the remaining approved sites that have not been installed yet, the vast majority are expected to enroll in D3.

Q65. Why is it important to continue offering the make-ready rebates to site hosts?

A65. The business case for installing and operating chargers is still extremely challenging and, as suggested above, incentives are still needed today to deploy the charging infrastructure required to support EV adoption. The network of publicly available EVSEs is not sufficient for near-term demand (let alone future growth) as shown in Table 7 below. The Company is requesting $3.9 million for this element, which can support the make-ready Service Connection and rebates for up to 250 Level 2 ports and 50 DCFCs through the test period.

Table 7. State of Charging Infrastructure in DTE Electric's Territory[48]

	Existing Ports	**Needed by 2023 (52,000 EVs)**	Estimated DTE Rebates[49]	Estimated Remaining Gap in 2023
Total Level 2[50]	620	6,000	750	4,630
DCFC	110	730	124	496

Given the amount of charging infrastructure needed in DTE's electric service territory by 2023, nearly ten times the existing ports, it is critical for the Company to continue offering incentives and ensure charging deployment does not stall at

[48] Based on Department of Energy Alternative Fuels Data Center's EVI-Pro Lite tool, assuming 76% of drivers having access to home charging and a split of 30% 20-mile PHEVs, 10% 50-mile PHEVs, 20% 100-mile BEVs, and 40% 250-mile BEVs

[49] Includes the pipeline from the original Charging Forward pilot and the Expansion through the test period

[50] Includes workplace and public, not residential

such an important development stage in the EV market. As shown in Table 7 above, the amount of incentives DTE is proposing through the test period is still leaving a significant gap, demonstrating that the Company is not seeking to incentivize the entire comprehensive network recommended by the Department of Energy. Rather, DTE is aiming to create a limited network that is required to reduce range anxiety and ensure the EV adoption rates are realized, which is necessary to achieve the Michigan Healthy Climate Plan and the Regional Electric Vehicle ("REV") Midwest Coalition Memorandum of Understanding ("MOU") signed by Governor Whitmer in September 2021. The press release from the REV Midwest MOU states, *"Improving access to charging infrastructure and reducing range anxiety will support EV adoption and the next generation of American-made electric automobiles."*[51]

Q66. Are the Make-Ready Rebates needed if there are other sources of funding available such as Federal or State incentives?

A66. Yes; the goal of the Make-Ready Rebate is not to be a replacement for but rather be complementary to other available incentives and help deploy EV infrastructure across Michigan in this early market stage. For example, DTE has worked closely with the Michigan Department of Environment, Great Lakes, and Energy ("EGLE") and their Charge Up Michigan grant program, which actually *requires* applicants to first be approved through a utility incentive. State agencies have appropriately relied on utilities to perform a large portion of due diligence on their behalf (e.g., qualifying vendors, assessing grid impacts, and collecting data), and utilities are best suited to do this with their own incentives. The Company will

[51] https://www.michigan.gov/whitmer/0,9309,7-387-90499_90640-569470--m_2020_1,00.html

continue to work closely with governmental agencies as any potential Federal or State incentives become available for customers to ensure alignment and achievement of incentive goals.

Q67. Will the Company offer the same rebate amounts to site hosts with the expansion?

A67. Yes, for DCFCs. The tiered rebate structure for DCFCs described above is designed to offset the EV Supply Infrastructure cost, which has been sized appropriately for the chargers installed thus far. The Company believes this is the appropriate amount to balance offsetting costs and encouraging necessary deployment while still requiring investment from the site host, but it may adjust rebate amounts in the future if reasonable and prudent (e.g., if additional funding sources become readily available).

For Level 2 chargers, if the Expansion is approved and additional funding for Level 2 chargers becomes available, DTE proposes to decrease the rebate from $2,500 per port to $2,000 per port which is more in-line with the EV Supply Infrastructure cost of installing Level 2 ports from what the Company has seen thus far.

Q68. Does DTE want to introduce other elements under the Commercial Customer Support umbrella?

A68. Yes; DTE is proposing two additional elements under Commercial Customer Support: Charging Hubs and Transit Batteries.

Q69. What are the primary design features of Charging Hubs?

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A69. DTE would build, own, operate, and maintain sites with several high-powered DCFCs at appropriate sites when certain buildout criteria are met to justify the investment. The Charging Hubs would be primarily designed to serve multiple customers with Class 3-6 medium-duty ("MD") and/or Class 7-8 heavy-duty ("HD") fleet EVs, while also being available to light-duty passenger vehicles. The design and size of the Charging Hubs could vary based on the expected demand, but in general, the Charging Hubs will have approximately 12 DCFCs between 150kW and 350kW to start. Similar to truck stops, the charging spaces will be covered by a canopy to protect drivers from the elements with a restroom and vending facility available for convenience.

Q70. Why does the Company believe that DTE Charging Hubs are needed in the market today?

A70. While the upfront cost to electrify fleets is primarily driven by vehicle premiums, the cost of charging infrastructure can be significant, especially for MD and HD fleet owners that are looking to pilot just one or two EVs. The current publicly-available DCFC infrastructure is designed for passenger vehicles, which have smaller parking dimensions than what is required for larger MD and HD vehicles. Charging Hubs designed for MD and HD fleets allow commercial customers to pilot electrification at a relatively low cost and enables them to confidently accelerate their electrification journey.

Q71. Why is fleet electrification beneficial?

A71. Fleet electrification will be an important piece of the solution for Michigan to achieve its net-zero emissions target. Larger vehicles disproportionately emit

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GHGs compared to their on-road presence: approximately 27% of on-road emissions come from larger vehicles even though they make up only about 4% of the overall vehicle fleet.[52]

Fleet operators will also benefit from lower operational expenses of electric MD and HD vehicles. Diesel MD and HD vehicles get only about 6-10 miles per gallon in efficiency, which translates to about $0.30 to $0.50 per mile for fuel, assuming an average of $3 per gallon.[53] Based on the pricing supported by Witness Willis, "refueling" at Charging Hubs will be up to 40% less expensive than it is for diesel today. In addition to fuel savings, electric fleet operators could also realize maintenance savings up to 50% compared to their existing diesel vehicles.[54]

Q72. Why is it appropriate for DTE to own and operate Charging Hubs?

A72. DTE is uniquely suited to site Charging Hubs where there is both sufficient power supply and customer demand. Because DTE can identify ideal locations on its system, it can deploy Charging Hubs at a minimum total cost. Creating centralized Charging Hubs with shared usage has the potential to significantly reduce the total number of chargers required. For example, if DTE installed a Charging Hub with 12 DCFCs, it could serve as many as 100 vehicles every day of the week (a ratio of three chargers to 25 vehicles). If fleet owners each wanted to pilot one or two EVs and did not have a Charging Hub, they would each need to install at least one charger at their individual facilities (a ratio of one charger to two vehicles at best). Proactively siting Charging Hubs where there is more available capacity on the

[52] https://calstart.org/wp-content/uploads/2021/05/How-Zero-Emission-Heavy-Duty-Trucks-Can-Be-Part-of-the-Climate-Solution.pdf
[53] https://www.eia.gov/todayinenergy/detail.php?id=26832
[54] https://ww2.arb.ca.gov/sites/default/files/2020-12/201207costdisc.pdf

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system and creating better utilization of the chargers through shared usage will help minimize overall system improvement costs to DTE’s customers. A shared Charging Hub also provides a way for DTE’s C&I customers to have equitable access to charging by avoiding electrical system bottlenecks for fleet electrification in areas with many C&I customers, because ideally-located Charging Hubs could potentially serve all customers.

Q73. What buildout criteria would need to be met?

A73. DTE believes the following six buildout criteria should be considered for Charging Hub sites:

- Locations with sufficient DTE system capacity;
- At least 1,500 MD or HD fleet vehicles registered in surrounding zip codes within three miles of the site;
- Within two miles of a major roadway with at least 2,000 average daily traffic of commercial vehicles;
- Sufficient land available to install several DCFCs;
- An MOU with at least three customers showing intent to utilize the hub; and
- In or near a non-attainment zone for criteria pollutants.

If all of the criteria are met for a site, the Company would deploy a Charging Hub there. In the event there is a site in high demand for customers, but other criteria are not satisfied, the Company will explore other options to serve those customers. The Company is requesting $2.8 million to begin the design and construction on up to two Charging Hubs as long as the above criteria are met.

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Q74. How will the rate to use the Charging Hub be designed?

A74. The rate would be structured with a volumetric charge and session fee to reflect the cost that the Company incurs to serve the Charging Hub and a per session charge to offset a portion of the initial capital outlay to build it. See Witness Willis's testimony for pricing information. Charger capacities may vary from those described here, and to ensure flexibility, I have directed Company Witness Willis to design the rate for <200 kW chargers and >200 kW chargers.

Q75. What assumptions are being made around utilization and charging levels?

A75. DTE is assuming that MD vehicles will use the 150kW chargers and HD vehicles will use the 350kW chargers. In the first year of operation, the Company is assuming a total of 15 vehicles – 13 MD and two HD – would use the chargers daily, which would lead to about 3,750 sessions (656,000 kW-hour or "kWh") for the 150kW chargers and 575 sessions (293,000 kWh) for the 350kW chargers.

Q76. What key learnings is DTE seeking to gain from Charging Hubs?

A76. DTE is looking to increase electrification among MD and HD vehicles and will use Charging Hubs to better understand:

- Impact on DTE's customer base;
- EV adoption impacts (compared to customers without access to a Hub);
- Optimal design of Charging Hubs (including charger quantities and power outputs, usage fee, and locations); and
- Best practices for managed charging and/or peak-shaving solutions at a high-powered commercial site.

Q77. What are the primary design features of the Transit Batteries element?

A77. DTE is proposing to purchase transit bus batteries and recover its costs from participating transit agencies to facilitate and accelerate their journeys to electrification. The Company would work directly with bus manufacturers and transit agencies to make it as seamless as possible for the agencies to procure buses such that:

- From their perspective, they order the bus the same as they typically would from the manufacturer, but the upfront price is discounted by the amount of the battery; and
- Purchased buses could still qualify for other available funding sources such as Federal Transit Administration ("FTA") Low-No Emissions Grants.

While the batteries are on the bus, DTE would collect data on the battery and its charging pattern and transit agencies would be responsible for a monthly cost recovery fee through a new electric bus ("eBus") tariff, which can be found as Rider 21 in Exhibit A-16, Schedule F-8 sponsored by Witness Willis. After the utility's costs are recovered, a participating transit agency would take ownership of the battery. At the end of the battery's useful life on the bus, the transit agency would either need to repurpose or dispose of it themselves or they could return it to DTE at a fair market salvage value to repurpose the battery to benefit the grid. Although the Company anticipates taking ownership of the batteries after their useful life on the bus, the option of ownership for transit agencies is an important factor for transit agencies to be able to qualify for FTA funding in parallel.

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Q78. What is the background on the eBus tariff?

A78. The eBus tariff is based on the Pay as You Save ("PAYS") model, which was originally invented by the Energy Efficiency Institute, Inc. as a financial tool for climate solutions, primarily for building energy upgrades such as weatherization and heating, ventilation, and air conditioning ("HVAC") upgrades. Clean Energy Works ("CEW"), with oversight from the Global Innovation Lab for Climate Finance, adapted it to apply to clean transport, specifically transit eBuses to start. MPSC Staff requested a briefing by CEW on the tariff in its eighth stakeholder meeting for the MI Power Grid New Technologies and Business Models workgroup on May 19, 2021, and it was received positively by the group.[55]

Q79. Are the batteries useful beyond their life in the bus?

A79. Yes; per McKinsey & Company, *"these batteries can live a second life, even when they no longer meet EV performance standards…After remanufacturing, such batteries are still able to perform sufficiently to serve less-demanding applications, such as stationary energy-storage services."*[56] If this element is approved next year, the Company would expect the first bus with this ownership model to be put in-service in 2024 (due to the lead-time of bus procurement), which means the Company will have until approximately 2030 to plan for where and how batteries can best be repurposed and utilized on its system. Potential applications include storage for renewables, fast charging on critical circuits, customer back-up power, and/or peak shaving.

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[55] https://www.youtube.com/watch?v=jDoUGr9OUZE

[56] https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/second-life-ev-batteries-the-newest-value-pool-in-energy-storage

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Q80. What is the value of Transit Batteries as an enabler in today's market?

A80. Despite paying back over the life of the bus through significant fuel and maintenance savings, transit eBuses can have an upfront purchase premium of over 80%, which is extremely difficult for transit agencies to overcome.[57] Eliminating the largest source of the upfront premium, the cost of the battery, makes electrification much more manageable for transit agencies, especially when combined with additional sources of funding.

Q81. What are the impacts of transit bus electrification?

A81. Transit bus electrification benefits many stakeholders. In addition to lowering transit agencies' fuel and maintenance costs as described above, it also helps put downward pressure on rates, because most routes can be accommodated with overnight, off-peak depot charging. The Transit Batteries element will prioritize those cases to maximize net benefits to DTE's customers.

Second, combining DTE's proposed Transit Batteries with potential increased FTA funding for eBuses could greatly accelerate deployment in the state, enabling achievement of the Michigan Healthy Climate Plan referenced above. An eBus produces 62% fewer emissions than the average diesel bus, and this will only continue to improve as DTE achieves its own commitment to carbon neutrality.[58]

[57] https://afdc.energy.gov/files/u/publication/financial_analysis_be_transit_buses.pdf
[58] https://onlinepubs.trb.org/onlinepubs/tcrp/tcrp_rpt_226FactSheet3.pdf

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Q82. Is the Transit Batteries element designed to be rate neutral?

A82. Yes; although the initial cost of the battery will be funded upfront through rates, this element will be designed to recoup the associated increase in revenue requirement in full over time through the following two revenue streams:

1) Anticipated increase in revenue from overnight depot charging less the cost to serve this increased load over the life of the bus;[59] and

2) A monthly fee calculated upfront to cover the remaining gap in battery cost (Rider 21 referenced above).

A key principle of the eBus tariff is that the calculated monthly fee will be less than the estimated operational savings the transit agency would achieve from electrification. This also correctly incentivizes transit agencies to maximize bus usage, since the fee is fixed and recognizes that the more they drive the transit eBus, the more operational savings they can realize. Because of the long lead time to procure transit eBuses, the Company is currently requesting $0.4 million to deploy one bus through the test period.

Q83. What key learnings is DTE seeking from this element?

A83. DTE is seeking to increase the sample size of electric transit buses in its electric service territory to better understand:

- Optimized charging solutions to minimize grid investments while meeting the transit agencies' needs (e.g., depot charging solutions and charger to bus ratios) and

[59] Based on route mileage, eBus efficiency, charger deployed, and transit agency's electric rate.

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- Right sizing of bus battery packs to meet route requirements after adjusting for known cold-weather impacts.

Additionally, the Company is seeking to learn more about how batteries might be repurposed after their useful life on EVs and efficiently integrated into DTE's system at a lower cost than buying new, which could also help address any potential environmental impacts of recycling used batteries from EVs as adoption grows.

Q84. How are DTE Charging Hubs and Transit Batteries complementary to other Charging Forward elements?

A84. Charging Hubs are complementary to the eFleets Advisory Services component that was recently approved. As DTE approaches its commercial customers to help provide a roadmap to electrification, it will be able to provide a solution to customers near potential sites that are hesitant to install their own EVSE. Similarly, it will be able to provide insight back to the team on demand for potential future sites.

The Transit Batteries element is also complementary to eFleets and its available EVSE rebates for transit agencies up to $70,000 per charger. Paired with Advisory Services, DTE could be solving the issues of technology expertise, upfront bus premium, and charging infrastructure all at once for the transit agencies.

Lastly, both elements are complementary to each other, since used transit bus batteries could potentially be repurposed to serve as on-site storage at Charging

Hubs to alleviate any potential critical peak demand issues in the future as utilization of the sites grows.

Q85. What metrics will the Company use to evaluate the Commercial Customer Support component?

A85. For Make-Ready Rebates, DTE will continue to track participants, geographic diversity, site host verticals, site costs, deployed charger data, and additional sources of funding (e.g., from EGLE). It will also test and analyze how adjusting incentive levels and qualification criteria affects uptake.

For Charging Hubs, DTE will track utilization by charger power level, number of C&I customers supported, number of fleet vehicles supported, number of passenger vehicles supported, site costs (both deployment and ongoing maintenance), peak demand, load profile, and revenue collected.

For Transit Batteries, DTE will report number of buses deployed, average battery costs, transit agencies supported, number of supporting Charging Forward eFleets rebates issued, other additional sources of funding, average monthly fee, and estimated battery kWh available to be repurposed by year of coming offline.

D. Equitable Access to EVs

Q86. To date, have EVs and EVSE been evenly distributed throughout the U.S. and in Michigan?

A86. No; EV ownership is unequally distributed by demographics such as income, population, and race. Counting both new and used vehicle purchases, households earning less than $100,000 per year represent only 44% of EV purchases (but 66%

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of U.S. households), and Black and Hispanic car buyers make up only 12% of EV purchases (but 33% of the U.S. population).[60, 61, 62] EV ownership is also unequally dispersed along the urban-rural divide. From the International Council on Clean Transportation ("ICCT"), "*The 50 most populous metropolitan areas accounted for 80% of new 2019 U.S. electric vehicle registrations… and 55% of the U.S. population.*"[63]

Public EV charging infrastructure is also unevenly distributed, depending on the area's income, demographics, proportion of MUDs, and whether it is a rural area or not. A recent study in California showed public charger access is lower in areas with below-median household incomes and with majority Black and Hispanic populations. The charger access gap is even larger considering just publicly-funded public charging stations, where Black and Hispanic majority areas are approximately half as likely to have access. These public charger access disparities are more pronounced in areas with a higher proportion of MUDs. For areas with a similar proportion of MUDs, higher-income areas are twice as likely to have access to a public charger as lower-income areas. Adding to this disparity is that residents of higher-income luxury MUDs are not only more likely to have access to public chargers, but because of the amenities available, they are also more likely to have dedicated parking structures that enable them to install private residential chargers (compared to residents of lower-income MUDs).[64] Charging infrastructure is also

[60] https://escholarship.org/uc/item/0tn4m2tx
[61] https://www.census.gov/data/tables/time-series/demo/income-poverty/cps-hinc/hinc-01.html
[62]https://mtgis-portal.geo.census.gov/arcgis/apps/MapSeries/index.html?appid=2566121a73de463995ed2b2fd7ff6eb7
[63] https://theicct.org/sites/default/files/publications/EV-cities-update-aug2020.pdf
[64] https://www.sciencedirect.com/science/article/pii/S0967070X20309021

more scarce in rural areas. For example, not including Tesla chargers, the entirety of the Upper Peninsula has only 16 Level 2 chargers and 2 DCFCs.[65]

Q87. What are the equity implications of unequal EV ownership and EVSE access?

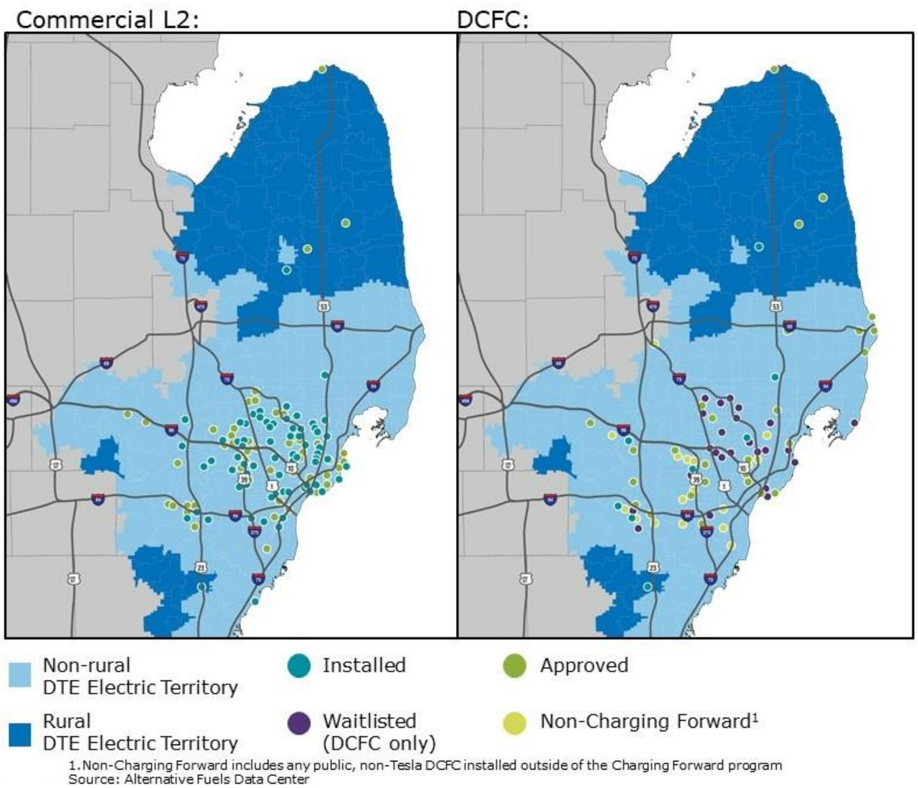
A87. The people most likely to benefit from reduced operational expenses and improved air quality are least likely to own EVs or have access to charging. A recent report by the ICCT found that the average vehicle-owning U.S. household earning less than $25,000 spends 50% of their income on vehicle ownership and operation annually compared to approximately 16% for median-income vehicle-owning households. This same report notes that EV-related savings tend to be higher for rural drivers than for urban or suburban residents because of the longer distances that rural drivers travel.[66]

Q88. What gaps in charging access have been noted from Charging Forward so far?

A88. The data DTE utilizes indicates only four Charging Forward residential rebate participants have been identified as low-income customers. Additionally, Charging Forward had low participation from commercial customers in rural areas: as of August 2021, only 14% of 36 total DCFC sites and 3% of 136 total Level 2 sites approved or deployed with Charging Forward funds are placed in rural areas as shown in Figure 2 below.

[65] https://www.atlasevhub.com/materials/ev-charging-deployment/
[66] https://theicct.org/sites/default/files/publications/EV-equity-feb2021.pdf

Figure 2. Map of Approved & Installed Charging Forward Rebates Compared to Rural Areas[67, 68]



Interest in Charging Forward has recently picked up at MUDs, with 12% of all installed or approved commercial charger sites located in that site host category.[69] While this initially seems positive, DTE has noticed that the installed chargers and approved applications tend to be for high-end MUDs, in line with the results of the California study described above.[70] In one instance, though, DTE was able to negotiate with an MUD owner to designate 25% of their approved Level 2 chargers in a lot located by a building of affordable housing units.

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[67] https://www.hrsa.gov/rural-health/about-us/definition/datafiles.html
[68] Data as of August 20, 2021
[69] Data as of October 21, 2021
[70] This was determined by evaluating the marketing for the MUDs where DTE has installed or approved chargers - most advertise luxury or upscale living.

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Finally, only 7 municipalities are represented in the 204 approved applications for Level 2 chargers or DCFCs, and within that, most of the municipality-owned chargers are located in Ann Arbor.[71] DTE would like to increase participation by municipalities because they manage a significant amount of public parking. Installing chargers in municipality-owned parking spaces or areas could provide more dependable EV charging for people without residential charging access and reduce range anxiety for all potential EV drivers. Municipalities would also be ideal partners if DTE decides to pilot EVSE on existing streetlights, as Kansas City did with its utility Evergy.[72]

Q89. Why is Equitable Access to EVs an important focus for DTE?

A89. There is an outsized need for TE support in communities that are underrepresented by current EV owners and lacking access to EV charging, and utilities are well-suited to address the gap as noted in the DTE's Role in TE section above.

DTE can realize long-term cost reductions by intentionally building out the EV charging network equitably in these early stages of EV adoption. Establishing various pilots, incentives, and ownership models now with a focus on equity will allow DTE to develop full-scale programs later that enable widespread EV adoption at a reasonable cost to customers. DTE is committed to addressing the needs of all its customers and intends to play an important part in furthering Michigan's goal to be carbon neutral by 2050. To achieve statewide carbon neutrality, all parts of the transportation sector must undergo TE, including those areas left behind by third-party service providers.

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[71] Data as of October 21, 2021

[72] https://www.smartcitiesdive.com/news/kansas-city-streetlight-mounted-ev-charger-pilot-aims-for-equity-accessibi/603805/

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Furthermore, “Advance Equity and Clean Environment” is one of the three objectives of the REV Midwest MOU. By advancing equity in its own programming, DTE is complementing the State’s efforts to foster equitable TE.[73]

Q90. What elements is DTE proposing under this new component?

A90. There are three elements of the Charging Forward Expansion that DTE is proposing to introduce under the new Equitable Access to EVs component: TNC Driver Rebates, Income-Eligible Rebates, and Commercial CaaS.

Q91. How do TNC Driver Rebates help enable equitable access to EVs?

A91. TNC Driver Rebates enable equitable access to EVs in three ways. First, TNC drivers themselves are more likely to come from populations that are underrepresented in the general EV owning population. About 65% of TNC drivers and riders identify as members of racial and/or ethnic minority groups.[74] Lyft, together with a University of Michigan research project, has already identified about 2,000 TNC drivers in Metro Detroit that could save up to $4,000 per year by switching to an EV.

Second, electrifying TNC vehicles brings the benefits of reduced air pollution to areas that currently have low EV ownership rates. The 2021 Economic Impact Report for Detroit from Lyft shows 59% of rides start or end in low-income areas.[75] Paired with the greater ethnic and racial minority makeup of riders and drivers

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[73] https://www.michigan.gov/documents/leo/REV_Midwest_MOU_master_737026_7.pdf
[74] https://drive.google.com/file/d/1Yol8oGRL38gKWRCOw9y65SxvY9dLMyyp/view
[75] https://drive.google.com/file/d/1Yol8oGRL38gKWRCOw9y65SxvY9dLMyyp/view

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alike, this means electrifying TNC vehicles would reduce the air pollution in areas where low-income, ethnic and racial minorities live and travel.

Third, electrifying TNC vehicles doubles as large-scale customer EV education because each ride in an EV has the potential to expose someone to an EV for the first time or convert an EV skeptic to an EV enthusiast over a series of rides.[76] Lyft's Denver EV program, which consists of 200 Kia Niro EVs, has given rides to over 500,000 unique passengers in the Denver metro area in less than two years. Furthermore, Lyft found through a survey that Lyft EV riders were 38% more likely to consider purchasing an EV for their next vehicle than riders who had not ridden in a Lyft EV.[77] Given the diverse make-up of the TNC driver population, electrifying TNC vehicles becomes not just a convenient educational opportunity, but also a primary driver of EV educational equity. In a report produced for DTE, EV diversity consultancy EVNoire emphasized that *"Diverse, underrepresented and under-resourced communities need to have outlets and opportunities to engage with diverse EV drivers who are reflective of their communities and can share EV experiences in an authentic, culturally appropriate, and meaningful way."*[78]

Q92. How would the TNC Driver Rebates be structured?

A92. DTE proposes a TNC Driver Rebate of $5,000 for EVs that meet the partnering TNCs' requirements (e.g., interior space, battery range, fast charging capabilities, etc.). DTE has already set aside $500,000 to test TNC Driver Rebates with its existing Charging Forward funds as reviewed in three different stakeholder

[76] https://sepapower.org/knowledge/utilities-and-ride-hailing-electrification-an-opportunity-for-all/
[77] Lyft data provided to DTE
[78] EVNoire, "DTE Drive the Future Executive Summary," 2021

meetings and submitted in both Annual Status Reports.[79] For the initial rollout, DTE is exploring a potential partnership with Lyft that would test different incentive payout structures to maximize electrification while ensuring the vehicles are still being used for ride-hailing (e.g., different upfront lump sums to reduce EV purchase price paired with mileage and/or ride bonuses to incentivize continued use for ride-hailing). If a larger fund becomes available through the Charging Forward Expansion, DTE will pursue partnership opportunities with other TNCs in its electric territory. The Company is requesting $0.5 million to fund rebates for up to 100 TNC drivers through the test period.

Q93. What justifies this level of rebate?

A93. The TNC Driver Rebate would enable DTE to create EV experiences for the public at a lower cost than formally organized Ride & Drives. Each EV deployed with the rebate is estimated to create 3,500 EV experiences annually, equaling a cost of $1.40 per experience, considering just the first year.[80] This compares to $200 per experience for a DTE-organized Ride & Drive. Given that the EV would likely be operating in its ride-hailing capacity for longer than a year, the effective cost to DTE for each EV experience courtesy of these TNC rides falls considerably.

Q94. What key learnings is DTE seeking from this element?

A94. Data shared from TNCs can provide insight into where (home vs. public), how (Level 2 vs. DCFC), and when TNC drivers charge their EVs. It can also help DTE determine where there is the greatest need for additional charging infrastructure and

[79] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CFtGtAAL; Exhibit A-29, Schedule T1
[80] Assumes 40 rides per week and 1.7 passengers per ride (per Lyft data)

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how that can best be integrated with the grid to maximize net benefits to its customers.[81] Additionally, DTE will continue to test inclusive messaging and diverse messengers to communicate this rebate to its intended audience. Finally, DTE is seeking to learn how to best engage riders with EV education while in the vehicles and enhance their EV experience.

Q95. Why are Income-Eligible Rebates needed?

A95. EVs currently cost over $10,000 more on average to purchase than the equivalent gasoline vehicle, which makes it harder for lower-income households to purchase, despite operational savings. However, as the technology improves, prices fall, and the used car market develops, this difference is forecasted to fall to only $2,500 by 2025 and reach parity around 2028.[82] Making incentives available to underserved communities now and stacking them with other available incentives (such as federal tax incentives, Charging Forward Residential Rebates, etc.) will help ensure that communities that can benefit most from EVs have the opportunity to participate earlier.

Q96. How would Income-Eligible Rebates be structured?

A96. DTE would offer $1,500 rebates to eligible customers for purchasing or leasing a new or used EV under a total all-in purchase price of $50,000. DTE customers could be eligible for this rebate in one of two ways:

1) Verifying the customer’s participation in an income-eligible public assistance program like Michigan Food Assistance (“SNAP”), or the

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[81] Phillips, Erin, “Utilities and Ride Hailing Electrification: An Opportunity for All,” Smart Electric Power Alliance, 2021. https://sepapower.org/knowledge/utilities-and-ride-hailing-electrification-an-opportunity-for-all/ Accessed 8/11/21.

[82] https://theicct.org/sites/default/files/publications/EV-equity-feb2021.pdf

customer participates in income-eligible DTE assistance programs like the Energy Efficiency Assistance Program; or

2) Verifying the customer's income is under 400% of the Department of Health and Human Services poverty guidelines, which translates to approximately $51,000 for a one-person household (or about $123,000 for a five-person household).[83]

DTE will work with stakeholders and others to determine how the rebates can be issued at point-of-sale (or as close as possible), since needing to cover the costs upfront may be a limiting factor for many qualified customers. The Company would also require recipients of the income-eligible rebates to be participants of its Residential Rebates or BYOC pilots if they have a residential Level 2 charger to help ensure charging takes place off-peak when it is beneficial to the system. The Company is requesting approximately $1.9 million for this element to support up to 1,300 rebates for customers through the test period.

Q97. What justifies this level of rebate?

A97. DTE benchmarked other utilities and found that four have received approval to offer EV rebates ranging from $250 to $5,500 to customers. Additionally, California utilities have joined with the California Air Resources Board to offer $1,500 point-of-sale price reductions. All five of these are shown in Table 8 below.

[83] https://www.federalregister.gov/documents/2021/02/01/2021-01969/annual-update-of-the-hhs-poverty-guidelines

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Table 8. Utility Approved EV Rebate Summary

Utility	**Rebate Range**	**Terms**
Pasadena Water & Power[84] (income-eligible program)	$250 - $1500	$250 for new or used EV + $250 for local dealership + $1000 for low-income
New Hampshire Electric Co-op[85]	$600 - $1,000	$600 for new or used PHEV, $1,000 for new or used BEV
Southern California Edison (“SCE”) [86]	$1,000	Used BEV or PHEV
Xcel Energy (income-eligible program)[87]	$3,000 - $5,500	$5,500 for new BEV or PHEV, $3,000 for used BEV or PHEV
California Clean Fuel Reward[88] (funded by multiple CA utilities)	$1,500	$1,500 for new EV (at point-of-sale)

Most of the rebates apply to all utility customers. In the case of Xcel Energy and Pasadena Water & Power, this rebate is income-eligible and gives qualified customers up to $5,500 and $1,500, respectively. Additionally, DTE’s proposed rebate amount of $1,500 is still less than the estimated NPV gross margin that each EV would add to the grid over its lifetime (see Table 11 below).

Q98. Why did the Company set income eligibility at 400% of the federal poverty guidelines?

A98. DTE has analyzed three other approved utility income-qualified programs by PG&E, Pasadena Water & Power, and Xcel Energy, and found that all use some kind of categorical eligibility, with PG&E and Xcel Energy also using income verification for those applicants whose income was not already verified by another program. These three programs are summarized below in Table 9.

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[84] https://ww5.cityofpasadena.net/water-and-power/incomequalifiedelectricvehicles/
[85] https://www.nhec.com/drive-electric/
[86] https://evrebates.sce.com/
[87] https://www.xcelenergy.com/staticfiles/xe-responsive/Marketing/21-07-533_CO-EV-CarRebate_app_P03.pdf
[88] https://cleanfuelreward.com/

Table 9. Utility Income-Eligible Programs

Utility	**Program Purpose**	**Rebate Amount**	**Income Qualifications**
PG&E (approved) [89]	Cover the cost of purchasing or installing EV charging equipment	$2,500	Categorical qualification, or household income no more than 400% of federal poverty guidelines
Xcel Energy (approved) [90]	EV purchase/lease rebate	$3,000 - $5,500	Categorical qualification, or household income below one of the following three metrics: 60% of the state of Colorado's median income, 200% of the relevant federal poverty level, or 80% of area median income.
Pasadena Water & Power[91]	EV purchase/lease rebate	$1,500	Categorical qualification

Due to the current lack of Michigan state incentives available to stack with the DTE EV rebate, and based on guidance from automakers, DTE chose to align its income qualification threshold with PG&E to test adoption impacts at that level for Michigan.

Q99. How will DTE try to offset the costs of Income-Eligible Rebates?

A99. DTE will create a pathway for voluntary donations to offset this element's cost. The Commission approved a similar donation pathway for DTE's MIGreenPower ("MIGP") program, called the MIGP Low-Income Donation Pilot (MPSC Case No. U-20713, Order dated June 9, 2021). In this pilot, DTE will collect funds from

[89] https://www.pge.com/en_US/residential/solar-and-vehicles/options/clean-vehicles/electric/empower-ev-program.page
[90] https://www.xcelenergy.com/staticfiles/xe-responsive/Marketing/21-07-533_CO-EV-CarRebate_app_P03.pdf
[91] https://ww5.cityofpasadena.net/water-and-power/residentialevrebate/

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customers to 1) subsidize MIGP subscriptions for other eligible customers and 2) partially fund community-based solar array projects. If Income-Eligible Rebates are approved as part of the Expansion, the Company will seek to apply lessons learned and best practices from the MIGP Low-Income Donation Pilot to Income-Eligible Rebates. Additionally, should any funding become available for income-qualified customers to purchase an EV, the Company will work with the State of Michigan to ensure the offerings are complementary (as it does for the Make-Ready Rebates today).

Q100. What key learnings is DTE seeking from this element?

A100. DTE is looking to understand:

- How rebating the cost of an EV impacts EV ownership and participation in Charging Forward from qualified customers;
- Charging behavior of underrepresented customers; and
- Impact of inclusive messaging and diverse messengers to promote this rebate to its intended audience.

Q101. What is DTE proposing for the Commercial CaaS element?

A101. DTE is proposing a true utility make-ready model for Commercial CaaS. In this model, DTE would install the chargers on behalf of the site host and would own and fund all the electrical infrastructure costs up to the chargers (both the EV Service Connection and EV Supply Infrastructure). The site hosts would own and operate the chargers and fund them through a fee on their monthly electric bill (after the Make-Ready Rebate is applied).

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Commercial CaaS differentiates from the Make-Ready Rebates DTE offers to site hosts today. With Make-Ready Rebates, DTE only provides a fixed rebate, DTE does not own any assets beyond the meter, and the site hosts are responsible for funding and installing the chargers upfront.

Q102. What customer segments would qualify for this element?

A102. The following four customer segments would qualify for Commercial CaaS: Environmental Justice Communities ("EJCs"), MUDs, rural areas, and municipalities. All four would qualify for both Level 2 and DCFC installations. The Company is requesting approximately $1.2 million for this element, which would support 150 Level 2 ports and 4 DCFCs through the test period.

Q103. What is Environmental Justice and what is an EJC?

A103. Michigan's EGLE defines Environmental Justice ("EJ") as *"the equitable treatment and meaningful involvement of all people, regardless of race, color, national origin, ability, or income … critical to the development and application of laws, regulations, and policies that affect the environment, as well as the places people live, work, play, worship, and learn."*[92]

The Environmental Protection Agency (EPA) has an EJ screening tool, EJScreen, that combines environmental and demographic data to provide 11 EJ indices for each community, expressed in percentiles relative to other communities.[93] EGLE is developing a Michigan-specific EJ screening tool, MIEJScreen, that will score communities based on environmental conditions and population characteristics

[92] https://www.michigan.gov/environmentaljustice/0,9615,7-400-98505---,00.html
[93] https://www.epa.gov/ejscreen/what-ejscreen

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such as traffic density, wastewater discharge, poverty, and race.[94] DTE may use EJScreen, MIEJScreen, or another tool or method, to identify communities eligible for that segment of the Commercial CaaS element. For the purposes of this testimony, DTE refers to these communities as EJCs.

Q104. Which MUDs would qualify for Commercial CaaS?

A104. MUDs will qualify for Commercial CaaS if they provide affordable housing. Affordable housing would include:

- Public housing;
- Privately-owned and government-subsidized MUDs (participating in programs such as Housing Choice Vouchers, Low Income Housing Tax Credit, etc.); and
- Privately-owned MUDs that can show they house low-income residents.

DTE would also provide Commercial CaaS to MUDs that can show they house vulnerable populations or have another reasonable characteristic at the Company's discretion (e.g., TNC driver residents).

Q105. How does Commercial CaaS help enable equitable access to EVs?

A105. Commercial CaaS incentivizes charger installation in areas that have low participation in Charging Forward thus far as described above. It significantly reduces both the complexity of installation and the upfront funding required by the site host. Public charging reduces range anxiety – even for those with access to

[94] https://www.youtube.com/watch?v=E-Lo6SvN_Kg

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overnight charging at home – and enables EV ownership for people without access to home charging.

Q106. What are your thoughts with regard to electric utility ownership and operation of the EV Supply Infrastructure?

A106. Other utilities such as Eversource, National Grid Upstate New York ("UNY"), and SCE already offer a true make-ready model, with National Grid UNY and SCE also making special offers for site hosts in underserved areas.[95] National Grid UNY and SCE provide more support for MUDs in disadvantaged communities, and SCE is also approved to rebate maintenance and networking costs for 10 years for MUDs located in these areas.[96,97] Both of these utilities identify disadvantaged communities using a state-wide screening tool, such as the one EGLE is creating. Aside from precedents at other utilities, it is reasonable and appropriate for DTE to experiment with different ownership models to see what approaches are most reasonable and prudent, as well as evaluate which ownership structures successfully expand charging access for underserved customers before committing fully to one ownership model for a larger scale and longer-term program.

Q107. What key learnings is DTE seeking to gain from this element?

A107. DTE seeks to learn:

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[95] https://www.eversource.com/content/ema-c/residential/save-money-energy/explore-alternatives/electric-vehicles/charging-stations/artner-with-eversource
[96] https://www.nationalgridus.com/Upstate-NY-Business/Energy-Saving-Programs/Electric-Vehicle-Charging-Station-Program
[97] https://www.sce.com/evbusiness/chargeready/multifamily

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- Whether additional support through Commercial CaaS will increase participation of site hosts from the four qualified customer segments compared to the Make-Ready Rebates element;
- If the increased participation and associated benefits outweigh the additional costs and operational burden compared to the Make-Ready Rebates element; and
- EV adoption rates in the zip codes surrounding the partnering Commercial CaaS site hosts.

Q108. How is the Equitable Access to EVs component complementary to the rest of Charging Forward?

A108. TNC Driver Rebates are complementary to Customer E&O since it can create thousands of additional EV experiences each year. TNC Driver Rebates is also complementary to Commercial CaaS, since DTE can use data from the rebates to best determine where Commercial CaaS should be applied (especially as it relates to MUDs for TNC drivers).

Additionally, Commercial CaaS is complementary to the Make-Ready Rebates because a customer approved for Commercial CaaS is also eligible to stack the incentive with the Make-Ready Rebate (so long as its terms & conditions are met).

Finally, the TNC Driver Rebates and Income-Eligible Rebates are complementary to Charging Forward's managed charging incentives, since they can be combined to further maximize benefits for the participants and DTE's customers.

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Q109. What metrics will the Company use to evaluate the Equitable Access to EVs component?

A109. For TNC Driver Rebates, DTE will track vehicles deployed, rides completed, incentives issued, route information, charging behavior, driver demographics, and participant surveys in coordination with its TNC partner(s). For Income-Eligible Rebates, DTE will track rebates issued, vehicle information, participant demographics, and participation in DTE managed charging incentives. Lastly, for Commercial CaaS, DTE will track charger deployment in the four targeted customer segments, associated deployment costs, charger utilization data, and community characteristics.

E. Program Development

Q110. What elements make up the Program Development component?

A110. An Emerging Technology Fund and Program Administration make up the fifth and final component of the Charging Forward Expansion.

Q111. Is an Emerging Technology Fund necessary?

A111. The EV Market is fast-paced and has rapidly evolving market dynamics. Staff recognized these characteristics and recommended that DTE *"aggressively test new and novel practices and technologies to ensure that new load associated with EV charging maximizes net benefits to all ratepayers"* (MPSC Case No. U-20162, Order dated May 2, 2019, p. 113). DTE agrees it needs to be proactively involved in new technology demonstrations to prepare for widespread EV adoption in the future, but the fast-paced market is not well-suited to regulatory lag. DTE currently lacks a timely source of available funding, so the Company is typically not in a position to partner with companies on new technology demonstrations. DTE has had to turn down several opportunities to partner with companies working on new technologies that have the potential to benefit customers in the long-term.

Michigan's Office of Future Mobility and Electrification ("OFME") is frequently facilitating the conversations with these companies in an effort to establish Michigan as a leader in the future of EV technologies to bring economic development opportunities to the state. Oftentimes, these companies are even looking for a demonstration location that would evolve into their North American headquarters, creating new jobs for the State of Michigan. "Elevate Economic Growth and Industry Leadership" is also one of the core activities of the REV Midwest MOU, in which Michigan committed to deploying electrification and other technology in collaboration with utilities, among others. Establishing an Emerging Technology Fund allows the Company to test new technologies, support economic development, and prepare for widespread EV adoption in the future at the same time. The Company is requesting $0.9 million to be used on qualifying demonstrations through the test period.

Q112. What types of demonstrations would qualify for funding from the Emerging Technology Fund?

A112. While it's difficult to predict what types of new technology or practices will manifest over the next few years, the Company envisions to use the Emerging Technology Fund to:

- Test cutting edge EV-grid integration solutions on its system (e.g., vehicle-to-building/grid, wireless charging, active load management, etc.);

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- Trial new and novel practices and/or approaches to engaging underserved communities (e.g., car-sharing);
- Test second life applications for used EV batteries; and
- Reduce emissions from the transportation sector and/or further economic development opportunities.

Q113. How would DTE ensure this element's expenditures are reasonable and prudent?

A113. To ensure collaboration and alignment across key stakeholders, DTE proposes to create a small Advisory Committee of external experts and DTE to evaluate opportunities and recommend whether the Company should proceed or not.

Q114. How does DTE propose to execute the Charging Forward Expansion broadly?

A114. DTE proposes to have a team of fourteen full time equivalent ("FTE") employees administering and executing the Charging Forward Expansion, three of which would be carryover from the original Charging Forward pilot.

Q115. What are the proposed roles for the fourteen Charging Forward FTEs?

A115. Although it depends on the final Order and adjustments from this proposal, DTE anticipates the following roles would be needed to successfully implement the Expansion as currently proposed: manager(s), program manager(s), sales associate(s), marketing analyst(s), strategist(s), and DTE business unit liaison(s). The Company is requesting $1.8 million to fund the roles required to support Charging Forward.

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Q116. What is the proposed timeline for the Charging Forward Expansion?

A116. DTE has estimated expenditures through the bridge and test periods for the Expansion and intends to continue learning and refining its elements until either:

- The element is no longer justified with the state of the EV market;
- The element spend is not approved by the MPSC; or
- An appropriate approach for a full-scale program has been determined.

Q117. Does DTE think that a full-scale Charging Forward program will be necessary?

A117. Yes; DTE has shown that Charging Forward incentives are necessary to promote off-peak charging and to produce benefits to DTE's customers. As the EV market grows, the EV-owning population will shift from majority early adopters to majority mainstream customers. As this growth continues, DTE should continue to guide customer usage and infrastructure deployment patterns toward those that will maximize net benefits for all customers.

Furthermore, DTE was directed by the Commission to file a long-term plan, stating *"In addition to providing greater transparency in the company's Phase Two proposal, including a long-term plan in DTE Electric's next rate case will also inform the Commission's review of the company's plans to implement its EV Charging Forward program at full-scale"* (MPSC Case No. U-20935, Order dated March 19, 2021, pp. 5–6).

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Q118. When does DTE expect to have a long-term plan for operating a Charging Forward program at full-scale?

A118. The Company may be able to propose long-term solutions more quickly for some elements where it has already begun implementation (e.g., E&O, Residential Rebates, etc.), but others may take longer to test and validate (e.g., Charging Hubs, Transit Batteries, Commercial CaaS, etc.). Charging Forward has been in operation for approximately 28 months, of which 13 months were greatly impacted by the COVID-19 pandemic.[98] Additionally, the Company is still testing different incentive structures and offerings to gauge impact on EV adoption for all customers, charging infrastructure deployment, and charging behavior to determine how it can best maximize net benefits to its customers.

Q119. What does the Company view as appropriate next steps to work toward a full-scale program?

A119. The Company believes continuing to refine existing elements and testing new elements through the Charging Forward Expansion are the appropriate next steps to work toward a full-scale program. Through the existing Charging Forward pilot and the proposed Expansion, the Company is seeking to identify elements which are supporting the EV market, providing value to its participants, not overly burdensome on the Company, and justified from a utility customer perspective (e.g., the proven benefits it provides outweigh the costs, it is confirmed to be participant-funded or rate neutral, etc.). Once these elements are validated, DTE will share its findings with its stakeholders and propose to operate those elements at full scale.

[98] As noted in the 2nd Annual Status Report, usage from EVs did not recover to pre-pandemic levels until April 2021

Q120. What do stakeholders say about DTE's plans for the Charging Forward Expansion?

A120. DTE invited stakeholders from 34 organizations and hosted at least 14 separate meetings to solicit their feedback in advance of this proceeding and received verbal support to proceed with the Charging Forward Expansion proposal from all of them. Additionally, some of the stakeholders chose to submit Letters of Support (see Exhibit A-12, Schedule B5.9.3). At a high level, the Letters of Support largely demonstrate overall advocacy for DTE's guiding principles and corresponding Charging Forward Expansion design as well as the need to support the State of Michigan in its Healthy Climate Plan. Elements which are strongly supported and specifically addressed in the letters are summarized in Table 10 below.

Table 10. Strong Support for Charging Forward Expansion Components

Expansion Component	Strongly-Supporting Organizations
Customer E&O	Alliance for TE, Clean Fuels Michigan, GM, NextEnergy
Residential Level 2 Charging	Clean Fuels Michigan, Ford, GM, NextEnergy
Commercial Customer Support	Alliance for TE, Blue Water Transit CALSTART, Clean Fuels Michigan, DDOT, Ecology Center, EVNoire, Ford, GM, Greenlots, Lyft, NextEnergy, Proterra, SMART

Equitable Access to EVs	Alliance for TE, CALSTART, Clean Fuels Michigan, Ecology Center, EVNoire, Ford, GM, Lyft
Program Development	Alliance for TE, Clean Fuels Michigan, Greenlots, NextEnergy

Q121. How will DTE continue to engage stakeholders?

A121. DTE currently provides high-level status reports quarterly and a detailed status report annually to stakeholders via email in addition to filing them in the Case No. U-20162 docket. The Company also invites stakeholders to participate in discussion sessions about twice per year and has hosted four to-date. DTE recommends continuing all of these stakeholder engagement methods and activities for the Expansion to ensure the appropriate collaboration and alignment in Michigan.

III. <u>Cost-Benefit Analysis</u>

Q122. What are the Company's total expected costs for the Expansion?

A122. Exhibit A-12, Schedule B5.9, page 4 shows capital expenditures (lines 1 through 7), O&M expense (lines 8 through 14), and regulatory asset costs (lines 15 through 24) for the bridge period in column (e) and test period in column (f). Total estimated Charging Forward Expansion costs for the bridge and test periods are $0.4 million and $17.4 million, respectively, as shown in line 25.

Q123. What costs are included in capital?

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A123. As it does in its approved Charging Forward pilot, DTE plans to capitalize any EV Service Connection costs. These costs encompass all spending necessary to provide distribution service to meet the load needs of the charger up to the point of interconnection at the Company's service meter and are relevant for the Make-Ready Rebates and Commercial CaaS elements of the Charging Forward Expansion. DTE will own the transformer, the service drop, and the meter, which are all retirement units.

DTE will also capitalize the EV Supply Infrastructure costs for the elements where it is planning to own and maintain these assets as it does the EV Service Connection. Elements with DTE-owned EV Supply Infrastructure include Residential CaaS, Commercial CaaS, and Charging Hubs. Additionally, the Company will capitalize the chargers themselves when owned and maintained by DTE Electric, as is the case for Residential CaaS and Charging Hubs.

Lastly, DTE plans to capitalize batteries for the Transit Batteries element, because it intends to purchase the battery on behalf of transit agencies.

Q124. What costs are included in O&M?

A124. On-going annual expenditures to run and maintain the programs are being requested through O&M expense, which is in-line with advancing toward a long-term program. That applies to the following elements of the Charging Forward Expansion: Customer E&O, TNC Driver Rebates, Charging Hub (O&M portion), Residential CaaS (O&M portion), and Program Administration.

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Q125. What costs are included in the regulatory asset?

A125. As discussed by Company Witness Uzenski, DTE is seeking to continue regulatory asset treatment for its existing Make-Ready Rebates, Residential Rebates, BYOC, and EV-Ready Builder Rebates elements. Per the Commission, *"DTE Electric is authorized to create a regulatory asset to recognize deferred EV program costs with the amortization of those costs over five years beginning the year after the costs are incurred. Further, the Commission authorizes the company to include recovery of the resulting amortization expense in rates and include the deferred net unamortized balance of EV program costs in rate base. However, the program costs will not actually be recovered until they have undergone a future reasonableness-and-prudence review in a rate case"* (MPSC Case No. U-20162, Order dated May 2, 2019, p. 115).

DTE is also seeking accounting authority to defer and amortize the EV Rate Tool, Income-Eligible Rebates, Commercial CaaS (for the EVSE portion), and the Emerging Technology Fund as regulatory assets pursuant to Case No. U-20162 Order dated May 2, 2019, above. The Company believes these elements are appropriate for regulatory asset treatment because they have the same characteristics as the existing regulatory asset elements: timing of spend is uncertain and spend can vary significantly year after year. The Commission concluded regulatory asset treatment is justified for elements with those characteristics because it *"balances the risk between the company and the customer"* (MPSC Case No. U-20162, Order dated May 2, 2019, p. 114).

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Q126. What net present value ("NPV") benefits does DTE estimate each EV provides to the grid?

A126. In its original proposal for Charging Forward in 2018, the Company estimated the NPV of gross margin that each EV sale provides toward DTE's electric system fixed costs over its lifetime ("benefits") is in the range of $2,100 to $2,800. Since 2018, the Company has updated its input assumptions based on the following market updates and lessons learned from Charging Forward:

- The Company was previously only considering the efficiency difference between BEVs and PHEVs, but in the updated analysis, the Company is also now considering the efficiency of light-duty trucks ("pickups") as they use more energy than smaller cars and represent 20% of new sales of the overall vehicle market.[99] Multiple pickup models are expected to be released in 2022, and the Ford F-150 Lightning amassed more than 120,000 preorders in only two months.[100]
- The Company updated the average revenue rate for an EV from $0.14/kWh in 2018 to between $0.11-$0.12/kWh today based on what rates Charging Forward participants selected for both residential and commercial chargers; and
- DTE was previously assuming that all commercial charging for an EV took place during critical peak for its low-end estimation. Based on actual Charging Forward data, the Company now uses a weighted average for on-peak charging of 15%.[101]

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[99] https://www.forbes.com/wheels/news/shoppers-snap-up-pickup-trucks/
[100] https://www.cnbc.com/2021/07/28/ford-says-reservations-for-f-150-lightning-electric-pickup-top-120000.html
[101] Residential charging is 80% of charging on average and is outside of the critical peak window 12% of time; commercial charging is the remaining 20% and is outside of the critical peak window 75% of time

DTE Electric's Distribution Grid Plan ("DGP") considered grid impacts from increased EV adoption as part of the scenario planning process (described in further detail in Section 3).[102] While the distribution system currently has limited existing capacity to accommodate load growth, up to 5% EV penetration can be accommodated in most areas without creating significant additional loading constraints. Using the same forecast above, EV penetration is expected to rise to about 1.5% through 2023, so minimal system impacts are expected during the test period. Using these updated parameters, the NPV benefits each EV adds to the system is estimated to be between $1,800 and $2,250 as shown in Table 11 below.

Table 11. EV NPV Benefits Assumptions, 2018 and Current

Assumption Description	2018 Value	Current Value	Key Assumptions for Updated Analysis
Annual EV electricity usage (kWh)	3,900	4,085	•0.31 kWh/mile for cars •0.53 kWh/mile for pickups •11,520 miles/year
Life of each incremental EV (years)	10	10	
Weighted average revenue rate ($/kWh)	$0.14	$0.11-$0.12	•80% from residential •20% from commercial
PSCR + Fuel Supply Cost	$0.033	$0.034	
Critical Peak charging (%)	30%	15%	•12% from residential •25% from commercial
NPV Gross Margin Incremental EV Sales ($)	$2,100-$2,800	$1,800-$2,250	•Discount rate of 6.79%

Q127. What total system benefit does DTE expect from EV adoption over the bridge and test periods?

[102] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000Uc0pkAAB

A127. As shown in its forecast curve above (Figure 1), DTE projects about 32,000 EVs to be sold in its electric service territory in 2022 and 2023. Based on the NPV range in Table 11, the Company estimates NPV system benefit of approximately $57.6 million to $72.0 million from EVs added during the bridge and test periods.

Q128. Should the Company be using the total system benefits in its cost-benefit analysis for the Charging Forward Expansion?

A128. No; based on data collected from Charging Forward so far, the Company believes 61% should be subtracted from the 32,000 expected EV sales over the bridge and test periods for the purposes of the cost-benefit analysis of the Expansion, broken down in the following three ways:

- 13% for TOU enrollment absent an incentive: the Company estimates 13% of new EV drivers would enroll in TOU rates absent an incentive, since only 87% of Residential Rebate applicants said it influenced their decision to enroll in a TOU rate as mentioned above;
- 37% for no range anxiety: the company estimates 37% of potential EV buyers do not have range anxiety today, since only 63% of survey respondents perceived range anxiety as a barrier to purchasing an EV; and
- 11% for likely purchase: based on the same survey, 11% of non-EV owners stated they were “very likely” to purchase an EV as their next vehicle, so an Expansion is not likely to facilitate those sales.

After subtracting these three portions totaling 61% from expected EV sales in 2022 and 2023, approximately 12,500 remaining new EVs – and their associated benefits

– should be considered in the cost-benefit analysis for the Charging Forward Expansion.

Q129. Should any Expansion elements be excluded from the cost-benefit analysis?

A129. Yes; the elements that should be excluded from the cost-benefit analysis are those that are designed to be participant-funded over time: Residential CaaS ($2.3 million through the test period) and Transit Batteries ($0.4 million through the test period), totaling $2.7 million.

Q130. Should any additional revenue collected from the Expansion be included in the cost-benefit analysis?

A130. Yes; there are two incremental revenue streams that should be included in the cost-benefit analysis. First, the rate design for the Charging Hubs includes a capital contribution fee that is meant to offset some of the costs of the upfront capital that DTE will use to build the sites while still encouraging electrification by enabling fuel savings. This capital contribution fee should be included as additional revenue for cost-benefit analysis purposes and is estimated to be approximately $2.0 million over the first ten years of operation.

Second, incremental revenue received from participating Commercial CaaS site hosts on their monthly bill to partially fund the charger costs should be included in the cost-benefit analysis. For the chargers DTE estimates to deploy through the future test period, this is estimated to be approximately $0.1 million.

Voluntary donations for Income-Eligible Rebates will also help offset costs to DTE's customers, but the Company has not yet confirmed its approach for this, so it does not yet have a way to forecast the amount. Summing the other two estimated incremental revenue streams amounts to approximately $2.1 million to be included in the cost-benefit analysis.

Q131. Using that approach, what is the overall cost-benefit analysis for the Charging Forward Expansion?

A131. The overall NPV net benefits to DTE customers for the Charging Forward Expansion are estimated to be in the range of $9.5 million to $15.1 million as shown in Table 12 below.

Table 12. NPV Cost-Benefit Analysis of the Charging Forward Expansion (in millions)

	Low-End Estimate	**High-End Estimate**
System Benefits from EV Sales in 2022-2023	$57.6	$72.0
Less Benefits Not Attributed to Expansion	($35.1)	($43.9)
Less Expansion Costs	($17.7)	($17.7)
Plus Participant-Funded Elements	$2.7	$2.7
Plus Incremental Revenue	$2.0	$2.0
Total NPV Net Benefit of Expansion	**$9.5**	**$15.1**

Q132. Why is the Company not showing a cost-benefit analysis for each element?

Line No.

A132. It is difficult to prove benefits specific to each element because incremental impacts from each element are not always clear. For example, Customer Education & Outreach is a critical enabler for EV adoption and promoting managed charging. However, from a standalone perspective, it appears to just be a "cost" since no specific benefits can directly be tied to it. Charging Forward elements are designed to be complementary to each other and addressing gaps in the market. As such, and while still in the pilot phase, the Company believes it is appropriate to consider the cost-benefit analysis holistically instead of separately. However, based on the lower-end NPV benefits each EV provides to the grid of $1,800 from Table 11 above, Table 13 below highlights the number of EVs that would need to be sold to cover the projected spend for each element through the test period.

Table 13. Estimated EV Sales Required to Breakeven by Element

Expansion Element	Projected Spend ($, thousands)	EV Sales Required to Breakeven
Customer E&O[103]	1,450	806
Residential Rebates	400	222
BYOC	100	56
EV-Ready Builder Rebates	80	44

[103] Including EV Rate Tool

Residential CaaS	2,351	n/a; participant-funded
Make-Ready Rebates	3,858	2,143
Charging Hubs[104]	2,840	467
Transit Batteries	400	n/a; participant-funded
TNC Driver Rebates	500	278
Income-Eligible Rebates	1,917	1,065
Commercial CaaS[105]	1,171	597
Emerging Technology Fund	900	500
Program Management	1,752	973
Total	17,718[106]	7,151

Only about 7,150 EVs would need to be sold to cover the cost of the Charging Forward Expansion through the test period, significantly less than the number of EVs that DTE is attributing to the Charging Forward Expansion (12,500). The

[104] Based on additional NPV revenue of approximately $2.0 million offsetting the projected spend
[105] Based on additional NPV revenue of approximately $0.1 million offsetting the projected spend
[106] Difference due to rounding

Company believes this demonstrates the prudency of its investment to help accelerate TE, bring about the benefits of TE to all of its customers, and further the State of Michigan's climate goals.

3. RESIDENTIAL BATTERIES PILOT

Q133. What is DTE proposing for the Residential Batteries pilot?

A133. DTE is proposing a customer-sited behind-the-meter residential battery pilot for up to 500 residential customers. At full enrollment the batteries would provide 5 megawatts ("MW") of stored energy, or 10kW per customer. Participants would have access to use the stored battery energy in the event of an outage and would pay a monthly subscription fee for this backup power access. Outside of outage events, DTE would have access to use the battery to derive key learning to determine the best path forward pertaining to residential battery storage.

Q134. Does this meet the pilot definition and corresponding six objective criteria as defined in Case No. U-20645?

A134. Yes; similar to Charging Forward eFleets and the Charging Forward Expansion above, please see Exhibit A-12 Schedule B5.10.1 for a high-level summary of how Residential Batteries is meeting these requirements and the corresponding questions in this testimony that relate to each of the six objective criteria.

Q135. How will the Residential Batteries portion of your testimony be structured?

A135. The Residential Batteries testimony will be structured in the following sections:

I. Market Overview & Role of Utility;

II. Pilot Design; and

Line No.

III. Estimated Costs and Proposed Treatment.

I. Market Overview & Role of Utility

Q136. What are the current market dynamics for residential batteries?

A136. The residential battery market has been growing in recent years both nationally and in Michigan. Wood Mackenzie is forecasting a 16% per annum increase in residential battery adoption in the U.S. through 2025.[107] This increased demand is primarily driven by declining battery prices and distributed solar ("PV") advancements. Lithium-ion battery pack prices fell from $1,100 per kWh in 2010 to $137 per kWh in 2020, a decrease of almost 90%. Bloomberg New Energy Finance is predicting battery pack prices could be as low as $58 per kWh by 2030.[108]

Q137. What benefits does residential battery storage provide?

A137. Residential batteries are beneficial for both the installing customers and utilities. From an installing customer perspective, home battery storage offers a no-noise backup power solution for resiliency during outages. From a utility perspective, with the recent passage of the Federal Energy Regulatory Commission (FERC) orders related to energy storage coupled with guidance from the MPSC around the desire for more energy storage pilot programs, residential battery storage offers the utility an opportunity to explore and gain key learnings to best prepare for compliance to these initiatives.

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[107] Wood Mackenzie Power and Renewables – Presentation at Energy Storage Monitor 3rd Quarter Review – September 2020

[108] https://about.bnef.com/blog/battery-pack-prices-cited-below-100-kwh-for-the-first-time-in-2020-while-market-average-sits-at-137-kwh/

Line No.

Q138. Are there other reasons to conduct a Residential Batteries pilot now?

A138. In the coming years, distributed storage is expected to have various ways in which it can interact with the grid. The FERC has required its jurisdictional ISOs to provide standalone distributed storage resources with wholesale market access via Order 841, and FERC has also required that aggregated distributed storage resources have access to wholesale markets via Order 2222. MISO is currently in the process of preparing for its compliance with both of these directives. Implementing a pilot at this point allows the utility to also explore these directives which will assist the design of the future system that best supports widespread customer adoption. . Learning customer preferences and system interactions now, while the market is still nascent, will improve program design, customer satisfaction, and potential grid benefits in the future.

II. Pilot Design

Q139. What are the key design features of the Residential Batteries pilot?

A139. The proposed pilot would seek to enroll up to 500 customers and as many as 500-1,000 customer-sited batteries (depending on battery partner offerings) that will be controlled and owned by DTE. Should the customer lose power, the customer will have full access to the energy in the battery for resiliency during their outage event, which could be enough to power an average house for a day or more, depending on its usage.[109] The customer would pay the Company a monthly subscription fee for backup power access, and the Company will provide education and outreach around

[109] The typical residential customer uses 21 kWh per day, and the battery capacity proposed in the pilot is able to provide 27 kWh of usable energy, leading to just over a day of resiliency benefit for the average residential customer (or more if they conserve their energy usage)

Line No.

the capacity limits of the battery for enrolled customers. Outside of outage events, the Company would have full access to the battery to derive key learnings.

Q140. How will participants be charged?

A140. The pilot would be offered for free to 250 income-eligible customers residing in single-family homes on targeted circuits. For the remaining 250 customers, a tiered monthly subscription fee structure will be offered at pricing to be determined closer to the anticipated launch of the pilot.

Q141. Why are the pricing tiers an important design feature of the pilot?

A141. Tiered pricing allows for testing of customer interest at different price points to better understand customers’ willingness to pay for backup power. Comparing speed of uptake for different monthly fees – in combination with customer surveys – will help determine appropriate pricing strategies for resiliency as a service, which will inform a potential broader program offering to DTE customers in the future.

Q142. How will the pricing tiers be determined?

A142. Price points in similarly designed residential battery pilots have ranged from $29.99 to $49.99 per month. This is reflected in Table 14 below.

Line No.

Table 14. Monthly Pricing Benchmarking Results for Utility-Owned Residential Battery Storage

Utility	Monthly Subscription Fee
Green Mountain Power	$30: Pilot, $55: Full Program
Liberty Utilities	$50 ($25 per battery)
Consumers Energy	$29.99, $39.99, $49.99

Although the Company would seek to offer similar price points, the estimated deployment schedule has initial battery system placements occur in 2023. The Company recommends setting specific pricing closer to the anticipated pilot launch date when it can better understand and incorporate economic factors influencing battery costs (such as battery availability, unit costs, and supply chain disruption).

Q143. Why is it important to include the offering for free to a portion of pilot participants?

A143. It is important to offer the pilot for free to a portion of customers for two key reasons. First, to analyze the potential value that clustered residential battery storage can provide to the grid, it is critical to have at least 1MW of storage for a 13.2 kV circuit and 0.5MW for a 4.8kV circuit. With over 3,000 circuits on DTE's distribution system, the Company must restrict a portion of the pilot to a few high-priority circuits to ensure enough participants and batteries can be clustered together to achieve the level of storage required to obtain targeted NWA learnings. Without having more information about customers' willingness to pay, DTE anticipates that recruiting 50-100 DTE customers to join the pilot from one circuit

Line No.

could be challenging and may necessitate giving some of them a free subscription. Second, serving customers from a range of socioeconomic backgrounds will provide the opportunity for learnings across DTE's customer base to help ensure equitable access to the technology with any potential future offerings.

Q144. How will the Company identify targeted circuits for the pilot?

A144. The Company will identify targeted circuits using the following methodology:

1. Select substations with only one circuit overload so realized benefits can be traced to a single circuit;[110]
2. Prioritize circuits serving higher customer populations to ensure a large enough market to achieve desired circuit concentration; and
3. Match prioritized circuits to areas defined as EJCs (described above).

Concentrating participation on targeted circuits will help ensure equitable distribution of pilot value, both for the individual customers participating in the pilot and customers on the same circuit who are not involved in the pilot.

Q145. How will the Company identify customers who are eligible to receive the free subscription?

A145. DTE will prioritize income-eligible customers in EJCs for the free subscription. The Company will use the same criteria for income-eligibility as proposed for the Income-Eligible Rebates offered in the Charging Forward Expansion described above. However, DTE may broaden the eligibility criteria for the free subscription

[110] Circuit overload is defined as a circuit being above its 100% firm rating; by placing batteries on the circuit, the firm rating would drop below 100%

Line
No.

if necessary, to achieve the participation required on a circuit for measurable impact.

Q146. How does the Company plan to engage a battery provider to facilitate the pilot?

A146. DTE plans to conduct a request for proposal ("RFP") to identify battery providers that provide the most value to both the Company and pilot participants.

Q147. Does the pilot include a Bring Your Own Device ("BYOD") offering?

A147. The pilot does not offer a BYOD segment to start because the Company does not yet understand the appropriate incentive structure that should be offered to these customers. Additionally, DTE needs to first understand how to interact with and control the batteries. Learnings from this pilot will enable DTE to determine the best design for a potential larger program, which has been a successful approach for other utilities. For example, Arizona Public Service operated a utility-owned approach for its first residential battery pilot but included a BYOD offering in a subsequent offering.

Q148. What key learnings is DTE seeking to obtain through this pilot?

A148. Targeted key learnings from the Residential Batteries pilot include:

- Customers' willingness to pay for resiliency as a service;
- Average battery capacity dispatched in an outage event and customer satisfaction with resiliency duration;
- Quantifying initiatives, including NWA benefits, annual capacity auction, MISO TOU price difference, and any potential transmission savings;

- How to best control batteries;
- Exploring residential battery technology to assist with prepare for implementation of FERC Order 2222;
- Testing various outreach efforts and messaging to drive successful, diverse recruitment; and
- Understanding how a broader offering to the customer should be structured, if warranted.

Q149. What is the proposed timing of the pilot?

A149. The Company will operate the pilot and collect monthly fees for a period of 10 years, which corresponds to the useful life of the battery systems. DTE will seek to obtain key learnings by year three or four, depending on the time required for the pilot to achieve peak enrollment. Upon receiving approval from the Commission, the Company will seek to achieve its first battery placement within six months.

Q150. How will success of the pilot be measured?

A150. Success of the pilot will be measured from both a customer and utility perspective. From a customer perspective, customer satisfaction, as measured by participant surveys, will be the focused measure of success. From the Company's perspective, the primary measure of success would be understanding the key operational and financial impacts necessary to determine the scope, structure, and feasibility of a broader battery offering to the customer base and achievement of other key learnings identified above.

Q151. How will DTE engage key stakeholders?

Line No.

A151. DTE will share pilot updates and solicit feedback from key stakeholders (ranging from battery providers, environmental groups, regional organizations, and MPSC Staff) prior to pilot implementation. The Company would seek to structure pilot status reporting in a similar manner to the Charging Forward initiative with semi-annual status update meeting with interested parties and the preparation of an annual report to the Commission that provides insight into the pilot's progress and key learnings.

III. Estimated Costs and Proposed Treatment

Q152. What are the Company's total expected costs for the Residential Batteries pilot?

A152. Exhibit A-12, Schedule B5.10 shows the above costs broken down into projected capital expenditures (lines 1-5) and O&M expense (lines 6-10) for the bridge and test periods in columns (e) and (f), respectively. Line 11 shows total estimated Residential Batteries pilot costs for the bridge and test periods as $1.1 million and $3.3 million, respectively.

Q153. What costs are included in capital?

A153. DTE is requesting capital costs associated with the procurement and installation of up to 182 battery systems to the point of interconnection at the Company's service meter. The Company is also requesting capital costs for the IT solution needed to perform aggregation, monitoring, and billing functions. Finally, the Company will incur capital costs associated with DO studies that will measure the impact of the batteries on the Company's distribution system. Requested capital costs are $1.1 million for bridge period and $3.1 million for the projected test period.

Q154. What costs are included in the O&M?

A154. The Company is including personnel to execute the pilot, estimated call center expenses, and applicable education & outreach costs to promote the Residential Batteries pilot with its customers. The Company is requesting recovery of $0.2 million of O&M for the projected test year.

Q155. What are the expected revenues from the Residential Batteries pilot?

A155. Test year subscription fee revenue is estimated to be approximately $12,000 if we assume a similar pricing structure to other utility pilots mentioned above. Given the prices of battery systems today, breakeven economics are not possible without charging customers a significantly higher monthly subscription fee. As the pilot progresses, battery costs are expected to continue to decline as mentioned above, potentially leading to more favorable economics in future years.

Q156. Why should the Residential Batteries pilot be approved if the costs outweigh the expected revenues?

A156. There are important key learnings the pilot seeks to gain associated with the ability of storage to participate in wholesale markets under FERC Order 2222 in the coming years, and the pilot allows for exploration of this feature, which will also inform for any potential future program design. More specifically, in response to FERC Order 2222, the Company may see the introduction and growth of aggregated energy storage resources on its distribution system. In this environment, the Company's ability to track and potentially control associated electricity flows, especially during times of system distress, will be critical to the continued safe operation of the distribution system. The pilot proposed here will allow the Company to test and better understand the technical and operational needs and considerations of aggregated energy storage on its distribution system, including aggregated storage which may respond to wholesale market signals. The learnings driven through this pilot should better prepare the Company for the implementation of FERC 2222 and ensure it is able to safely operate its distribution system in this future environment.

4. MERCHANT FEES

Q157. What is the purpose of your testimony in this proceeding regarding merchant fees?

A157. The purpose of my merchant fees testimony is to support the recovery of debit and credit card payment transaction fees expense in the Company's rates.

Q158. What are merchant fees?

A158. Merchant fees are the transactional costs associated with the processing of debit and credit card payments. These costs, or fees, are expenses borne by the Company and levied by the customer's debit and credit card issuer and payment processor.

Q159. What type of debit and credit cards does the Company allow customers to utilize?

A159. DTE allows the use of all debit cards for bill payments. In addition, it allows customers to utilize either Visa or MasterCard credit cards. DTE has restricted the type of credit cards that are allowed for bill payment to these two card issuers as they offer a lower negotiated utility transaction rate for residential customers.

Line No.

Q160. What measures has the Company taken to minimize merchant fees?

A160. DTE continues to restrict the use of credit and debit cards for business customers with two mitigation policies that were proposed and approved by the Commission in prior rate cases:

1) In Case No. U-20162, the Company proposed excluding industrial customers in rate schedules D6.2, D8, D10, and D11 from using credit or debit cards (implemented August 2019); and
2) In Case No. U-20561, the Company proposed limiting the ability of debit or credit card payments to C&I customers whose preceding calendar year aggregate annual energy bill was less than $75,000 (implemented January 2021).

Q161. Did the Company, as directed by the Commission in Case U-20561, work with Staff on methodologies to better evaluate the impacts and attributions of merchant fees on customers?

A161. Yes; DTE worked with Staff and determined that no cross subsidization would occur across rate schedules related to merchant fees, addressing Staff's primary concern. This is addressed by Company Witness Maroun.

Q162. What is the Company projecting the merchant fee expense to be in the projected test period?

A162. The Company is forecasting $20.5 million of merchant fees in the test year as shown in Exhibit A-13, Schedule C.5.7.1, page 1, line 5 in column (g).

Line No.

Q163. How did the Company develop its test year merchant fee forecast?

A163. As shown in Exhibit A-13, Schedule C5.7.1, page 2, column (e), the Company calculated the 3-year average merchant fee growth rate that was experienced from 2018 through 2020. This growth rate was then applied to the actual merchant fee expense incurred in 2020 to develop the 2021-2023 merchant fee forecasts. The 2021 -2023 calculated amounts for non-residential merchant fee expense were reduced by the mitigation policy impacts.

Q164. What impact do the mitigation policies have on the merchant fee O&M expense?

A164. Exhibit A-13, Schedule C5.7.1, page 2, line 7 in column (i) shows that the O&M expense will be approximately $2.3 million less due to non-residential mitigation efforts. This reduces a projected expense amount for non-residential merchant fees of $3.7 million to $1.4 million.

5. ADVANCED CUSTOMER PRICING PILOT

Q165. Can you please explain the Company's Advanced Customer Pricing Pilot ("ACPP")?

A165. ACPP is a pilot program which began enrolling residential customers in the first quarter of 2021 to better understand residential customer preferences and responses to a variety of TOU rate plans, recruitment and messaging approaches, and ongoing engagement. A successful pilot will inform both how DTE designs different rate programs to customers and various techniques for customer outreach and engagement which might be more effective. The MPSC approved the pilot in

November 2019 in Case No. U-20602. I am supporting the portion of these costs that relate to:

- Customer Outreach and
- Evaluation, monitoring, and verification ("EM&V").

Please see Company Witness Pizzuti's testimony for Information Technology costs and Company Witness Sparks's testimony for Customer Service and Insight application costs.

Q166. What are the costs related to Customer Outreach and EM&V for the pilot?

A166. Exhibit A-13, Schedule C5.9.2, column (f) lines 3 and 5 show the cost for Customer Outreach and EM&V as $3.6 million and $0.9 million, respectively.

Q167. Can you provide an explanation of the Company's expenditures related to these line items?

A167. As described in Case No. U-20602, Customer Outreach costs are to ensure that customers are correctly assigned and contacted. It also covers costs associated with problem-solving should any execution issues arise. DTE is working with a supporting vendor to ensure best practices in advanced rate communication are used, which helped inform the communication strategy.

EM&V costs support statistically valid assignment of recruitment and control groups and the EM&V of pilot data. Support for pilot evaluation will ensure that analyses conducted with pilot-generated data are compelling, comprehensive, and provide the right insights as the Company progresses toward full implementation.

Line
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6. 2023 TOU ROLLOUT CUSTOMER OUTREACH

Q168. What is the role of Customer Outreach in the full TOU rollout?

A168. Company Witness Foley**'s** testimony discusses the Company's TOU full implementation proposal, and Customer Outreach will ensure that all residential electric customers are aware and informed that their base rate will be changed to a new TOU rate in May 2023 (with the ability to unenroll if they do not desire to remain on that rate).

Q169. What is the total O&M expense for Customer Outreach in the projected test period that DTE Electric is seeking to recover?

A169. As shown on Exhibit A-13, Schedule C5.9.2, column (e), line10, DTE is seeking to recover $8.1 million of O&M expenses in the projected test year.

Q170. Why is $8.1 million of O&M expense needed for Customer Outreach?

A170. In order to prepare customers for the upcoming change in their rate, they will receive a series of communications via multiple channels prior to the rate implementation meant to inform, educate, and provide tips for how to save on a TOU rate. Research will be conducted with message testing and focus groups in order to ensure that all communications developed are easy to understand and engaging for the customer. Advertising will be deployed to reach a broader population of customers and have a strong educational focus. The outreach will also include producing the following three videos:

- What a customer needs to understand about the new rate;
- The benefits of the new rate; and
- How to save money on the new rate by shifting usage to non-peak times.

Line No.

7. REGULATED MARKETING O&M EXPENSE

Q171. What is the total Regulated Marketing O&M expense for the projected test period that DTE is seeking to recover?

A171. As shown on Exhibit A-13, Schedule C5.9, column (k), line 18, DTE is seeking to recover $24 million of Regulated Marketing O&M expenses in the projected test year.

Q172. What was the Regulated Marketing O&M expense for the adjusted 2020 historical test year?

A172. As shown on Exhibit A-13, Schedule C5.9, column (e), line 18, Regulated Marketing total O&M expense for the adjusted 2020 historical test year was $15.6 million.

Q173. What does Regulated Marketing O&M expense include?

A173. Regulated Marketing O&M expense includes: Major Account Services, which manages new and existing customer relationships for C&I customer classes; Electric Marketing, which manages marketing campaigns to educate customers, develops new product and service offerings, and measures business performance; and Economic Development, which seeks to stimulate local economic growth and activity, including job growth through business attraction, retention, and expansion. Lastly, Regulated Marketing includes Demand Response Portfolio costs which are supported by Company Witness Farrell and amortization of the Charging Forward and ACPP regulatory assets supported by Company Witness Uzenski.

Line No.

Q174. What known and measurable changes is DTE Electric proposing to the historical test year amount?

A174. DTE Electric is proposing the following known and measurable changes to the historical 2020 test year Regulated Marketing O&M expense:

1) Inflation for 2021, 2022 and 10 months of 2023 in the amount of $1.2 million,
2) PEV Amortization ending in 2020 resulting in a reduction of $1.2 million,
3) Charging Forward regulatory asset amortization of $1.2 million as supported by Company Witness Uzenski,
4) Charging Forward Expansion O&M of $3.3 million.
5) ACPP regulatory asset amortization of $1.1 million as supported by Company Witness Uzenski,
6) Residential Batteries costs of $0.2 million; and
7) $2.5 million related to Demand Response programs supported by Company Witness Farrell.

Q175. What were the assumed labor and material inflation adjustment factors for 2020, 2021 and 2022?

A175. The assumed labor and material annual inflation adjustment factors were 3.1% for 2021, 2.9% for 2022 and 2.4 % (10 months of 2.9%) for 2023 as supported by Company Witness Uzenski.

Q176. What are your conclusions regarding the level of Regulated Marketing O&M expense for the projected test period?

A176. The Regulated Marketing O&M expense is a reasonable and prudent level necessary to support the new programs proposed by the Company in this proceeding, maintain the existing level of customer support to commercial and

Line
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industrial major account customers, support the Company's economic development activities and educate all customers regarding regulated Company offerings.

Q177. What are your thoughts concerning the level of DTE Electric's historical and projected capital and O&M expenses contained in your testimony?

A177. DTE Electric has been reasonable and prudent in past capital and O&M expenditures and I anticipate this to continue through the projected test period and beyond. I believe that DTE Electric has fully justified as reasonable and prudent its request for capital expenditures and O&M expenses that are set forth in my testimony and associated exhibits.

Q178. Does this conclude your direct testimony?

A178. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MICHAEL S. COOPER

Line No.

Q1. What is your name, business address, and by whom are you employed?

A1. My name is Michael S. Cooper (he/him/his). My business address is DTE Energy Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC (DTE LLC).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Business Administration Degree with a major in accounting and finance from the University of Toledo in 1994. I received a Master of Arts Degree in educational administration from Michigan State University in 1997.

Q4. What is your current position and work experience?

A4. My current position is Director of Compensation, Benefits & Wellness. I joined DTE Energy Corporate Services LLC full time in 2008 and held positions with increasing responsibility in Human Resources. In 2012, I became the Manager of Compensation and assumed my current position in 2017. Prior to joining DTE Energy, I was employed by Manpower as an on-site Staffing Program Manager and in other related positions for Visteon Corporation. I was previously employed at Robert William James & Associates as a recruiter with an emphasis in accounting and finance related positions.

Line No.

Q5. What are your responsibilities as Director of Compensation, Benefits & Wellness?

A5. As Director of Compensation, Benefits & Wellness, I have overall responsibility for the design, implementation, and administration of DTE Energy's compensation and employee benefits policies and practices.

Q6. Have you participated in DTE Electric or DTE Gas proceedings before the Michigan Public Service Commission (Commission)?

A6. Yes. I sponsored testimony in DTE Electric's most recent general rate cases (Case Nos. U-18255, U-20162 and U-20561) and in DTE Gas's most recent general rate cases (Case Nos. U-18999, U-20642 and U-20940).

<u>Purpose of Testimony</u>

Q7. What is the purpose of your testimony?

A7. My testimony will present an overview of employee compensation practices and benefit expense for DTE Electric for the 2020 historical test period and the 12 months ended October 31, 2023, projected test period. Specifically, I will:

1. Provide support for the Company's projected pension costs, other post-employment benefits costs (OPEB), active employee health care costs and the costs of other employee benefits, including adjustments to the historical test period for abnormally low self-insured medical costs in 2020 as a result of COVID-19 and a constant-dollar adjustment to normalize historical Active Healthcare expense;
2. Demonstrate the potential volatility in the Company's future pension costs, including the potential for negative pension costs, which demonstrates the

need for the deferral of the Company's actual pension expense to a Regulatory Liability or Asset, as more fully described by Company Witness Ms. Uzenski;

3. Discuss the potential impact of President Biden's COVID-19 Action Plan issued September 9, 2021;
4. Support the Company's labor cost escalation assumptions used in Witness Uzenski's development of the composite inflation factors for the projected test period;
5. Provide an overview of the Company's compensation philosophy for non-represented employees, including an analysis of salaries for non-represented positions as of December 31, 2020, relative to the market medians for comparable positions;
6. Describe the components of the Company's short-term and long-term incentive compensation plans and support the inclusion of the related expense in the Company's revenue requirement, exclusive of the costs related to DTE Energy's Top Five Executive Officers; and
7. Demonstrate that the quantifiable customer benefits of the Company's incentive compensation plans exceed the corresponding expense, as required by the Commission's traditionally mandated cost/benefit analysis of incentive compensation expense.

In summary, my testimony will support the reasonableness of the projected employee benefits and compensation expense to be incurred by DTE Electric for the projected test period.

Q8. Are you sponsoring any exhibits?

A8. Yes, I am supporting information on the following exhibits:

Exhibit	Schedule	Description
A-13	C5.11	Projected Operation and Maintenance Expenses - Employee Pensions and Benefits
A-13	C5.11.1	Willis Towers Watson Healthcare Trend Projection
A-13	C5.11.2	PwC 2022 Medical Cost Trend
A-13	C5.11.3	COVID-19 Active Healthcare Normalization Adjustment
A-13	C5.11.4	Constant Dollar Active Healthcare Adjustment
A-13	C5.12.1	Projected Operation and Maintenance Expenses – Qualified Pension Costs
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Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

EMPLOYEE PENSION COSTS

Q10. What are pension costs?

A10. Pension costs are those costs related to pension benefits DTE Electric provides to the majority of its employees under its defined benefits plan. The Company's defined benefit pension costs are recognized under U.S. Generally Accepted Accounting Principles (GAAP) Accounting Standard Codification (ASC) section 715-30 (ASC 715-30), formerly known as Statement of Financial Accounting Standard 87.

Q11. What are the components of pension costs?

A11. Pension costs are measured at the beginning of each fiscal year, under ASC 715-30, and include the following five pension cost components:

<u>Service Costs:</u> Service Costs represent the pension benefits earned by active employees, on a present value basis, during the current period. Service Costs are measured based on the expected benefits to be paid based on actuarial assumptions including current and projected salaries, expected employee turnover, and life expectancy.

<u>Interest Costs:</u> Interest Costs are the increase in the Projected Benefit Obligation (PBO) due to the passage of time during the current period. The PBO is the actuarial present value of benefits attributable to the pension benefit formula and

service accrued to date discounted back to current dollars at a discount rate selected at the prior year-end. A discount rate of 2.57% was used in determining the PBO at the end of the historical test year and interest costs during the projected test year are similarly based on 2.57%. Measuring the PBO as a present value at the beginning of each fiscal year requires the accrual of an interest cost for the current period at a rate equal to the prior year's discount rate. The discount rate used in measuring Interest Costs, as well as Service Costs for the 2020 historical test period, was 3.28%, based on the interest rate environment at the end of 2019 and projected benefit payments from the pension plan matched against a yield curve of corporate bond rates, rated Aa or higher, provided by Aon, the Company's independent actuarial firm. The 2.57% discount rate used for determining Interest Costs and Service Costs during the projected test year reflects the assumption that high-quality corporate bond interest rates at the end of 2022 will remain essentially unchanged from the rates prevailing in late December 2020. While the likelihood that interest rates at the end of 2022 will be as low as in late December 2020, the assumption of no changes in discount rates is consistent with traditional practice. The impact of potentially higher discount rates is discussed later in my testimony.

<u>Expected Return on Assets:</u> The Expected Return on Assets is an estimate of the expected investment return, during the current period, on the Market Related Value of the assets invested in the pension trust at the beginning of the year adjusted for both planned funding and benefit payments for the year. While actual year-to-year investment returns can vary significantly, the expected annual rate of return is determined based on long-term financial market expectations to avoid large swings in pension costs based on short-term investment performance. DTE Electric's

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expected annual return was 7.10% for the 2020 historical test year, as developed by NEPC LLC, the Company's independent investment consulting firm. The expected rate of return is assumed to be reduced to 7.00% in 2021, 6.80% in 2022 and 6.70% in 2023. The projections for 2021-2023 reflect a planned increase in fixed income asset allocation due to a projected increase in funded status.

<u>Unrecognized Gains and Losses:</u> The cost of Unrecognized Gains and Losses reflect the amortization of the accumulated changes in the PBO or the plan's assets resulting from experiences different from those assumed in actuarial measurements. Most notably, since the discount rate and return on assets assumptions are based on either point in time measurements, as in the case of discount rates, or long-term estimates, as is the case for expected rate of return on assets, differences can arise due to changes in the interest rate environment between year-end measurements and when the actual annual asset returns differ from long-term expectations. These gains and losses are deferred and the amount of the unrecognized balance in excess of a corridor equal to 10% of the greater of the PBO or the Market Related Value of assets is amortized based on a period equal to the average remaining service life of employees covered by the plans.

<u>Prior Service Costs</u>: The amortization of Prior Service Costs relates to pension plan design changes that will affect future benefit payments. When a plan provision is changed that will affect future benefit payments for existing employees or retirees, the incremental change in the PBO liability is amortized over the average remaining years of service life of the active employees.

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Q12. How are these pension costs expected to change between the historical test year and the projected year?

A12. As summarized on Exhibit A-13, Schedule C5.12.1, the Company's pension costs are projected to decrease from $92.9 million during the historical test year to $13.5 million for the projected test year. The decrease in pension costs between the two periods is due primarily to a decrease in Interest Costs arising from the relatively low discount rates as of December 2020 and an increase in the Expected Return on Assets due to higher asset balances (which is partially offset by the reduction in the expected annual rate of return on assets) and a decrease in the Amortization of Losses.

The Service Cost component is expected to increase by $1.0 million between the historical and projected test years, which reflects a decrease in the interest rates used to discount the future value of benefits earned by employees.

Interest Costs are anticipated to decrease by $22.8 million between the historical and projected test years, primarily due to the decrease in the discount rate from the 3.28% rate used in measuring interest expense in 2020 to the 2.57% rate used in the projected test period.

The Expected Return on Assets are projected to increase by $19.9 million between the historical test year and the projected test year due to increases in pension assets, which is partially offset by the reduction in the long-term expected asset return assumption. DTE Electric made pension contributions of $60 million in 2020 and

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transfers of $50 million in both November 2022 and November 2023 from the DTE Gas Non-Union pension trusts are planned.

The Amortization of Losses is projected to decrease by $36.7 million between the two periods. This decrease reflects the decrease in the balance of unrecognized losses due to loss amortization in the intervening years.

The Prior Service Cost amortization is projected to decrease by $1.1 million between the historical test period and the projected test year.

The total projected pension cost of $13.5 million is subsequently adjusted for the impact of costs transferred and capitalized, as described by Company witness Uzenski, which results in pension expense of $9.2 million for the projected test year.

Q13. Will the Company's actual pension cost be impacted by changes in discount rates and differences in the actual return on assets relative to the expected return?

A13. Yes. The Company's projected Pension costs are based on discount rates as of December 31, 2020, and the Company's expected rate of return on assets is based on long-term investment performance expectations based on the funded status at December 31, 2020. However, changes in the interest rate environment at any given year end and short-term variations between the actual annual rate of return and the expected annual rate of return can have a significant impact on the Company's actual annual pension costs.

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Q14. Have you quantified the impact on the Company's projected pension costs of alternative discount rate assumptions and an increase in the actual return on assets in 2021?

A14. Yes. Exhibit A-13 Schedule C5.12.2 reflects the impact on the Company's projected pension costs under two scenarios. The first scenario assumes that the actual return on pension assets in 2021 is 12.0% rather than the 7.0% annual rate of return assets in the base forecast and the second scenario, which is additive to the first, assumes that the discount rate in December 2021 is 100 basis points higher than the 2.57% assumed in the base forecast. While both the actual return on assets in 2021 and the actual discount rate as of December 31, 2021 were both lower than assumed in these scenarios, the directional impact is still true.

Q15. What is the impact on the Company's pension costs for the projected test year under these two scenarios?

A15. As reflected on Exhibit A-13, Schedule C5.12.2, the scenario of a 12% actual return on assets in 2021 results in the Company's pension costs for the projected test year decreasing to negative $7.9 million. The additional assumption of a 100 basis point increase in the December 2021 discount rate would decrease the Company's pension costs for the projected test year to negative $33.7 million. These estimates assume the Company's expected annual rate of return on assets will not change in future years, which is unlikely as the Company's existing investment policy provides for more conservative investment strategies, and accordingly, lower expected annual rate of return on assets, as the proportion of the pension liabilities funded increases. If the Company's expected annual rate of return on assets is reduced to 6.0% in 2022 and 2023 in recognition of the pension liabilities being

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fully funded as of December 31, 2021, the projected pension costs would increase by over $30 million in the projected test year to negative $3.6 million. These estimates further presume that the actual annual rate on assets will equal the expected annual rate of return in 2022 and 2023 and that there are no further changes in discount rates beyond December 31, 2021.

These analyses demonstrate the potential for extreme volatility in the Company's pension costs due to changes in actual results, as in the case of the return on assets, or changes in point in time measurements, as in the case of the discount rate. Moreover, this analysis also shows that the Company may, under certain circumstances, incur negative pension costs during the projected test year.

Q16. How does the Company propose to address this potential volatility and that future negative pension costs could be negative?

A16. Witness Uzenski proposes that due to the potential volatility and that the Company could incur negative pension costs in the future be addressed through the adoption of a deferral mechanism for pension expense similar to that in place for the Company's OPEB expense. While I have included pension expense of $9.2 million of pension expense for the projected test year, if the Commission adopts the Company's proposal to defer any actual pension expense to a Regulatory Asset or Liability, the pension expense for the projected test year would be eliminated.

<u>OTHER POST-EMPLOYMENT BENEFITS</u>

Q17. What are OPEB Costs?

A17. OPEB costs relate to the provision of retiree medical, dental, prescription drug and life insurance benefits. OPEB is a cost recognized under U.S. GAAP Accounting

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Standard Codification (ASC) section 715-60. Similar to ASC 715-30, OPEB costs are determined under ASC 715-60 at the beginning of each fiscal year.

Q18. What are the cost components of OPEB?

A18. OPEB has the same basic cost components as pension costs. They are:

Service Costs: Service Costs are the portion of the expected postretirement benefit obligation, on a present value basis, attributable to employee participation service during the current period. Service Costs reflect actuarial assumptions of employee turnover, age at retirement and expected longevity. Service Costs also depends on the estimated costs of providing these benefits subsequent to retirement and thus is impacted by both current medical cost levels and expected medical cost inflation.

Interest Costs: Interest Costs are the costs arising from the current period interest on the discounted Accumulated Postretirement Benefit Obligation (APBO). The APBO was discounted to today's dollars based on the discount rate of 2.58% in December 2019 and the interest cost on the APBO during the projected test year is also based on 2.58%. The discount rate used in measuring Interest Costs, as well as Service Costs for the 2020 historical test period, was 3.29%, based on the interest rate environment at the end of 2019, as determined similar to the measurement of the Company's pension costs. The 2.58% discount rate used for determining Interest Costs and Service Costs during the projected test year reflects the assumption that high-quality corporate bond interest rates at the end of 2022 will remain essentially unchanged from the rates prevailing in December 2020.

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Expected Return on Assets: The Expected Return on Assets is an offset to the costs of OPEB, based on the expected long-term return on assets invested. The expected annual rate of return was 7.20% during the historical test year and is projected to be 6.70% in 2021 and 6.30% in 2022 and 2023 due to an expected increase in asset allocation to fixed income.

Amortizations: This cost component includes the amortizations related to deferred Gains and Losses as well as Prior Service Costs. Accumulated gains and losses, outside the 10% corridor, as described for pension costs, are amortized over the current estimated remaining service lives of active participants. Prior Service Costs are amortized over the estimated remaining service lives of active participants, at the time of the last plan change, to the age at which these employees are fully eligible for the benefits.

Q19. How are these OPEB costs expected to change between the historical test year and the projected test year?

A19. As reflected on Exhibit A-13, Schedule C5.12.3, the Company's OPEB costs are projected to decrease from negative $27.0 million in the historical test year to negative $35.0 million during the projected test year, which represents a decrease in OPEB costs of $8.0 million. This reduction in OPEB costs is primarily due to the reduction in Interest Costs due to the reduction in the discount rate from 3.29% to 2.58%.

Q20. What are the underlying causes of the changes in OPEB costs between the historical test year and the projected test year?

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A20. The cost components for OPEB are reflected on Exhibit A-13, Schedule C5.12.3 for the historical test year and projected test year. These include the following changes:

Service Costs are estimated to increase by $1.9 million between the two periods. This increase reflects the impact of the reduced discount rate used to measure future benefits and updated retiree health care inflation assumptions.

Interest Cost is expected to decrease by $8.5 million between the two periods due to the decrease in the interest rate from the 3.29% rate used in 2020 in measuring interest costs to the 2.58% rate used in the projected test year.

The Expected Return on Assets is projected to increase by $4.6 million between the two periods, which results in a decrease in OPEB costs, due primarily to the increase in assets arising from investment gains recognized in 2020 partially offset by the reduction in the expected annual rate of return on assets in 2021 and beyond.

The amortization of (Gains)/Losses is projected to decrease by $4.6 million between the two periods due to a decrease in the balances subject to amortization.

Finally, the amortization of Prior Service Costs is projected to remain essentially flat between the two periods.

The total projected OPEB cost of negative $35.0 million is adjusted for the impact of the costs transferred and the portion of OPEB costs capitalized, as described by Witness Uzenski.

Q21. Has DTE Electric externally funded its OPEB costs?

A21. Yes. DTE Electric has funded the OPEB costs included in the Company's revenue requirement adopted by the Commission in previous orders through a Voluntary Employees' Beneficiary Association (VEBA) trust and an Internal Revenue Code Section 401(h) trust.

Q22. Will the Company externally fund its OPEB liability in the future?

A22. No. Since the Commission approved the Company's proposal in Case No. U-20561 to continue the deferral of the projected negative OPEB expense initially approved by the Commission in Case No. U-17767, the Company's current and projected revenue requirements do not include any OPEB expense and thus there is no obligation for the Company to externally fund its OPEB liability.

Q23. Is the negative OPEB expense included in the Company's proposed revenue requirement?

A23. No. Witness Uzenski sponsors the Company's proposal to continue to defer the projected negative OPEB expense to the accumulated regulatory liability. Thus, the projected negative OPEB expense is not reflected in the Company's proposed revenue requirement.

Q24. What is the basis for the projected cost increase in the New Hire Retiree VEBA?

A24. The New Hire Retiree VEBA costs on Exhibit A-13, Schedule C5.11 reflect the costs of the DTE Supplemental Retiree Benefits Plan that is offered in lieu of the traditional retiree healthcare plan for eligible employees. The increase in New Hire Retiree VEBA expense from $6.0 million in the historic test year to $11.4 million in the projected test year is based on annual escalations of 25%, based on recent experience. This increase reflects the growth in the number of plan participants due to new hires. Since the New Hire Retiree VEBA is offered in lieu of the Company's traditional retiree healthcare plan, which is closed to new participants, these costs are offset by avoided OPEB costs.

Q25. What other post-employment benefits are offered by the Company?

A25. The Company also offers an Employee Savings Plan, commonly referred to as a 401(k) plan. The Employee Savings Plan allows eligible employees the opportunity to put aside a certain percentage of their annual earnings that the Company matches up to 6% of annual salaries and wages for non-represented employees and for most represented groups. In addition, employees, hired after the defined benefit pension plan was closed to most new hires, receive an additional employer contribution of 4% of annual salaries and wages. The Employee Savings Plan costs, on Exhibit A-13, Schedule C5.11, are projected to increase from $28.5 million in the historic test year to $35.4 million in the projected test year based on projected 3.0% annual pay increases, as well as the impact of the higher employer contributions for newly hired employees that participate exclusively in the defined contribution retirement plan. The combined effect of higher employee salaries and

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wages as well as new hires in the historical test year is expected to increase the Company's Employee Savings Plan costs by 8.0% per year.

ACTIVE EMPLOYEE BENEFIT PROGRAMS

Q26. What other benefit programs are offered to active employees?

A26. The Company offers a competitive active employee benefits package for the attraction and retention of a skilled workforce. The major components of the benefit package include choices among several medical plans, dental plans, vision care and life insurance options. The components of these benefits are summarized on Exhibit A-13, Schedule C5.11, on lines 8 through 14. The medical, dental and vision expenses are projected to increase from $41.4 million in the historic test year to $58.0 million in the projected test year. This increase reflects the normalization of the 2020 Active Healthcare costs for the non-recurring impact of a reduction in the Company's self-insured medical and dental costs resulting from the COVID-19 pandemic and an adjustment to reflect an historical average of constant dollar costs, which results in a total increase of $9.2 million, as described below. The 2020 normalized Active Healthcare costs of $50.5 million is then escalated for the adjusted medical plan trend of 5.5% in 2021, 5.0% in 2022 and 4.5% in 2023, as more fully described below. The $0.2 million of Life Insurance costs in 2020 are projected to remain essentially flat in the projected test year. Benefit Plan Administration Fees are projected to increase from $5.4 million in 2020 to $5.8 million for the projected test year due to the overall rate of inflation as measured by the Consumer Price Index.

Q27. What is included in the normalization adjustments for Active Healthcare costs in column (c) of Exhibit A-13, Schedule C5-11?

A27. The total Active Healthcare normalization adjustment of $9.1 million consists of two separate adjustments. The first adjustment relates to the normalization of the Company's Active Healthcare costs in 2020 for the impact of the COVID-19 pandemic on the Company's self-insured medical and dental costs and is an increase of $3.4 million. The second adjustment represents a normalization of the Company's adjusted total Active Healthcare costs for a five-year average of the Company's constant dollar Active Healthcare costs, which represents an increase of $5.7 million.

Q28. How did the COVID-19 pandemic impact the Company's Active Healthcare costs in 2020?

A28. The Company experienced a substantial reduction in its self-insured medical and dental claims in 2020, as a result of the combined effects of Government ordered shut-downs, capacity constraints experienced by medical service providers during the peak periods of the pandemic and the generally reduced utilization by employees and dependents of healthcare services. While the Company also incurred claims directly related to COVID-19 cases by employees and dependents, those costs were more than offset by overall reduction in claims.

Q29. Should the Company's 2020 incurred Active Healthcare costs be adjusted to exclude the impact of the reduction realized as a result of the COVID-19 pandemic?

A29. Yes. The Company's actual Active Healthcare costs in 2020 were impacted by the unusual and non-recurring impact of the COVID-19 pandemic that must be

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eliminated from the historical test year. The elimination of the measurable impact on the Company's Active Healthcare costs is necessary not only because the number of claims made in 2020 were driven to non-representatively low levels, but also because of the high likelihood that a meaningful portion of the medical services not rendered in 2020 will only be postponed into future years, not eliminated. This will likely increase the Company's Active Healthcare costs beyond the levels reflected in the medical trend factors used to escalate for future Active Healthcare costs.

Q30. Have you quantified the impact on the Company's 2020 actual Active Healthcare costs of the COVID-19 pandemic?

A30. Yes. Exhibit A-13, Schedule C5.11.3 reflects a comparison of the Company's actual self-insured medical and dental costs in 2020 compared to 2019 related to active employees. The total self-insured medical and dental costs in 2020 were $43.2 million compared to 2019 claims of $48.8 million, which represents a reduction in absolute terms of $5.6 million. However, according to the PwC projection of medical cost trends in 2020 independent of any impacts of COVID-19, as explained in Exhibit A-13, Schedule C5.11.2, the Company's Active Healthcare costs should have increased by 6.0% in 2020, which is reduced in this analysis to 5.5% as a result of the Wellness program, as described more fully below. The comparison of the actual 2020 claims of $43.2 million to the expected 2020 claims of $51.4 million shows that the Company's self-insured claims were $8.3 million less than the level expected in the absence of the COVID-19 pandemic, as reflected in column (d), line 6 of Exhibit A-13, Schedule C5.11.3.

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However, this $8.3 million reduction is inclusive of the cost of actual self-insured claims in 2020 related to COVID-19 medical treatment of $1.1 million. When the actual COVID-19 claims are excluded, the total unexpected change in the Company's self-insured medical and dental costs increases to $9.3 million, which represents the estimated impact in 2020 of the COVID-19 pandemic on the Company's Active Healthcare costs that must be reflected as a normalization adjustment to the Company's 2020 costs.

In addition to COVID-19 claims, the Company also incurred costs associated with COVID-19 for medical services related to testing and other measures of $3.1 million that should also be excluded from the Company's normalized 2020 Active Healthcare costs. The subtraction of the costs of COVID-19 claims in 2020 of $1.1 million and the COVID-19 medical services costs of $3.1 million results in a net adjustment to the Company's Active Healthcare costs of $5.2 million, as reflected in column (e), line 12 of Exhibit A-13, Schedule C5.11.3, prior to any recognition for the portion of the Company's costs that are capitalized and transferred. The net adjustment to the Company's 2020 Active Healthcare expense is an increase of $3.4 million. The potential for additional COVID-19 related costs related to increased vaccination and testing requirements is discussed later in my testimony.

Q31. What is the Constant Dollar Normalization Adjustment to 2020 Active Healthcare costs?

A31. The year-to-year volatility of actual Active Healthcare costs makes the use of any one historical period's expense a potentially unreliable starting point in the determination of projected Active Healthcare costs. Accordingly, the adjustment of $5.2 million, as derived in Exhibit A-13, Schedule C5.11.4, represents a normalization of the Company's actual 2020 Active Healthcare costs that is designed to eliminate the volatility of the Company's Active Healthcare costs through the quantification of the Company's historical Active Healthcare costs per employee as adjusted for national historical healthcare cost trends. This results in an average of the Company's actual Active Healthcare costs per employee stated in a basis that eliminates the impact of historical healthcare cost inflation.

Q32. What is the basis for your conclusion that year-to-year Active Healthcare costs are volatile?

A32. The Company is self-insured for about 70% of its total Active Healthcare costs. Self-insurance results in the level of Active Healthcare costs incurred by the Company being highly impacted by the mix and severity of medical treatments administered to employees and their eligible dependents. The Company's Active Healthcare costs are also impacted by the number of employees and dependents eligible for coverage, which can vary from year to year due to both changes in the number of employees and the number of employees that opt out of the Company's medical plans.

Q33. Have you quantified the degree of volatility in the Company's Active Healthcare Costs?

A33. Yes. The actual annual percentage change in the Company's Active Healthcare costs for the years 2010 through 2020, as adjusted for a one-time credit in 2018, is reflected in Table 1 below.

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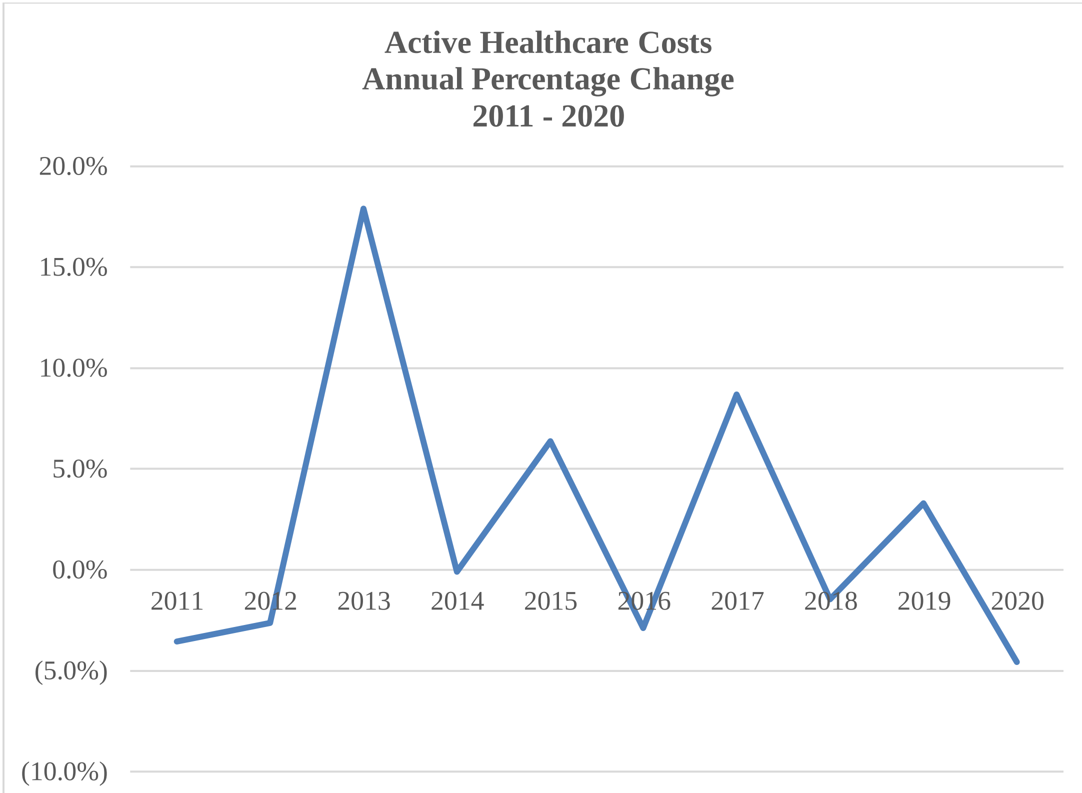
Table 1



This chart shows that the Company's actual Active Healthcare costs have changed relative to the prior year by as much a 18% in 2013 to a decrease of almost 5% in 2020 and demonstrates that Active Healthcare costs can vary significantly from year-to-year.

Q34. Are the annual percent changes reflected in this chart the same as the Company's Active Healthcare expense?

A34. No. The annual percent changes reflected in Table 1 above are based on the Company's total Active Healthcare costs before reduction for the portion of those costs that are capitalized. Due to changes between years in the portion of Active Healthcare costs capitalized, annual changes in Active Healthcare expense can be distorted. For example, the portion of Active Healthcare costs capitalized in 2011

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was about 22% while in 2020 the portion of Active Healthcare costs capitalized has increased to over 33%. The increase in the proportion of Active Healthcare cost capitalized reflects the increase in the Company's annual capital expenditures. Accordingly, the quantification of the annual changes in the Company's Active Healthcare costs before adjustment for the portion of costs capitalized is a more meaningful method of identifying the true annual variability of Active Healthcare costs because it eliminates the distortion of year-to-year changes in the proportion of costs capitalized.

Q35. Is there a method of normalizing the Company's historical Active Healthcare costs to determine a more reliable starting point in determining Active Healthcare costs for the projected test year?

A35. Yes. The variability in the Company's actual Active Healthcare costs can be normalized through the use of constant dollar Active Healthcare costs on a per employee basis. This allows the normalization of the inherent volatility in historical Active Healthcare costs through the elimination of the impact of healthcare price level changes and changes in the level of employees.

Q36. How did you determine a constant dollar average of the Company's Active Healthcare costs on a per employee basis?

A36. Exhibit A-13, Schedule C5.11.4 reflects the Company's actual Medical, Dental and Vision components of the actual Active Healthcare costs for the years 2016 through 2020, before the impact of the costs capitalized and transferred. These costs are divided by the simple average of employees at the beginning and end of each year to develop the Active Healthcare costs per employee. The Active Healthcare costs per employee for each year is then adjusted for the actual percent increase in medical trends, as reported by PwC on page 3 of Exhibit A-13, Schedule C5.11.2. While the actual medical trend rates reported by PwC for the years 2016 through 2019 are used, the PwC trend rate of 6.0% for 2020 is adjusted downward by 0.5% for the impact of the Company's Wellness program. (The Life Insurance and Benefit Plan Administration Fees have been excluded from this analysis because these items are subject to separate escalation factors.) Adjusting the Company's actual Active Healthcare costs for the overall increases in medical costs experienced by a broad universe of employers and insurance providers, as reflected in the PwC study, enables the separation of the Company's year-to-year variability that is driven by changes in utilization by the Company's employees and their dependents from changes to overall healthcare cost trends.

The adjustment of each year's Active Healthcare costs per employee produces a five-year average cost per employee on a constant dollar basis of $11,363. By multiplying this amount by the 2020 average number of employees the total constant dollar Active Healthcare cost of $77.8 million is generated. This represents a $8.6 million increase relative to the Company's incurred Active Healthcare costs in 2020, as adjusted for the COVID-19 normalization. This amount is adjusted for the 66.7% of Active Healthcare costs charged to expense and results in a constant dollar normalization adjustment of $5.7 million.

Q37. Has the Commission previously addressed the propriety of a constant dollar Active Healthcare adjustment?

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A37. Yes. In its Order in DTE Gas Company's most recent rate case the Commission declined to adopt the constant dollar Active Healthcare cost adjustment based on its conclusion that "a multi-year average adequately captures the volatility of the expense" (Case No. U-20940, Order issued December 9, 2021, p. 157).

Q38. Do you agree with the Commission's conclusion in Case No. U-20940?

A38. No. Although the Commission acknowledged that Active Healthcare costs are volatile, it used one year's actual Active Healthcare costs as the starting basis for projecting future Active Healthcare costs. (i.e., actual 2019 costs x multi-year average percentage of 3% x 3 years). The Commission's adoption of a multi-year average of the historical annual percentage increases in the Company's Active Healthcare costs in determining the escalation of historical test period Active Healthcare costs for the projected test period did not address whether the historical test period costs were a representative starting point to which the escalations should be applied.

Q39. Does a multi-year average of historical increases in Active Healthcare costs fully recognize the impact of volatility?

A39. No. Averages of historical increases in the Company's actual Active Healthcare costs only measures the annual changes in those costs, which is distinguishable from the determination of the proper starting point to which those projected increases should be applied. The decline in the Company's actual Active Healthcare costs in 2020 because of the COVID-19 pandemic, as previously discussed, provides compelling reinforcement that unadjusted historical costs can be a poor basis for projecting future Active Healthcare costs.

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Q40. Are there any useful analogies to the Company's constant dollar Active Healthcare adjustment?

A40. Yes. From a broad perspective, the constant dollar Active Healthcare adjustment should be regarded as means to neutralize the inherent volatility in the Company's actual Active Healthcare costs by restating the historical costs in current dollars, much as "nominal" price levels are routinely adjusted for the effects of inflation so as to develop inflation adjusted "real" prices. This allows for a meaningful comparison of costs among years without the distortion of changes in price levels.

More specifically, the Company has traditionally adjusted its actual annual historical emergent replacement expenditures for inflation to develop a base spending level used in developing projected costs. This approach was explicitly adopted in the Company's last rate case where the Commission concluded "Adding inflation to the historic five-year historical actual spend is appropriate for calculating the starting point for normalized expenditures." (Case No. U-20561, Order issued May 8, 2020, p. 86). The constant dollar Active Healthcare adjustment merely applies the same logic used in the development of historical emergent replacement costs in recognition of the volatility in those costs.

Q41. How is this constant dollar normalization adjustment reflected on Exhibit A-13, Schedule C5.11?

A41. The total constant dollar normalization adjustment of $5.7 million is allocated to the Active Healthcare cost components of Medical Expense, Dental Expense and Vision expense based on the proportion of the expenses for each of these categories in 2020, as shown on Exhibit A-13 C5.11.4, column (m), lines 18 through 20.

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Q42. Is the normalization of 2020 Active Healthcare costs necessary after the impact of COVID-19 has been eliminated?

A42. Yes. The adjustment for COVID-19 only eliminates the identifiable impact of the COVID-19 pandemic on the Company's self-insured medical and dental plans in 2020. Accordingly, even after 2020 is adjusted for the impact of COVID-19 on the self-insured plans, there remains significant volatility in total Active Healthcare costs among the years that is not addressed through the 2020 COVID-19 adjustment.

Q43. What is the basis for the future medical plan trend for Active Healthcare expense?

A43. The annual unadjusted medical plan trend factors of 6.50% for 2021, 2022 and 2023 is based on projections for healthcare trends provided by the health care experts at Willis Towers Watson (WTW), as reflected on Exhibit A-13, Schedule C5.11.1 and explained below. These unadjusted trend factors are reduced by 0.50% each year to reflect the expected savings to be realized by the Company's Wellness program. Accordingly, the Active Healthcare expense projections are based on the normalized 2020 actual expense escalated by the adjusted medical trend factors of 5.50% in 2021, 5.00% in 2022 and 4.50% in 2023.

Q44. How were the trend factors determined?

A44. The first step in the development of the trend factors is to develop the Allowed Trend. The Allowed Trend is subsequently adjusted for the Company's actual plan design to develop the future Medical Plan Trend applicable to the Company. The

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use of national trends by WTW is premised on the view that data for any individual company is not a credible basis for future expectations.

Q45. Do you have any collaborating sources that support the reasonableness of Aon's projections?

A45. Yes. A study released in 2021 by PwC's Health Research Institute as reflected in Exhibit A-13, Schedule C5.11.2, projects that medical costs will increase by 7.0% in 2021 and 6.5% in 2022. As described in the PwC study, these year over year changes are derived with the impact of the COVID-19 pandemic excluded from the prior year's numbers.

Q46. What are Other Employee Benefits Costs?

A46. The costs of the Company's Other Employee Benefits are reflected on Exhibit A-13, Schedule C5.11. These costs include a variety of other benefits including Accrued Vacation, Supplemental Severance Plan, Wellness Plan, Long-Term Disability expense, costs associated with the Affordable Care Act (ACA), General Benefits expenses as well as the Supplemental Savings Plan and Deferred Compensation Plan. Also included in Other Employee Benefits Costs is the amortization of the medical refund liability, as approved by the Commission in its Order in Case No. U-20162 that is sponsored by Witness Uzenski.

Q47. What is the basis for your projection of the Company's Accrued Vacation expense?

A47. Accrued Vacation expense can vary from year-to-year based on the timing of the usage of earned vacation time by employees as well as forfeitures and the value of

Line No.

unused vacation at year-end. Consistent with past practice, the projected Vacation Accrual expense reflected on Exhibit A-13, Schedule C5.11 is based on the average of the recorded expense for the most recent five years, which is then escalated by projected 3% labor annual cost increases through the end of the projected test year. Accordingly, Accrued Vacation expense recognized in 2020 of $5.6 million is adjusted to $0.2 million for the projected test year.

Q48. What is the basis for the Supplemental Severance Plan cost projections?

A48. Aon developed the projected cost of this plan. The Supplemental Severance Plan was adopted in 2016 that provides certain eligible employees that are covered by the MCN Energy Group, Inc. (MCN) Traditional pension plan a lump sum payment that is designed to provide retirement benefits comparable to the pension benefit provided under DTE Energy's traditional pension plan. Since certain employees of both DTE Electric and DTE LLC are covered by the traditional MCN pension plan because they were employees of MCN or its subsidiaries at the time of DTE Energy's merger with MCN, the cost of the Supplemental Severance Plan is borne by DTE Electric to the extent the labor costs for the affected employees are allocated to DTE Electric. The Supplemental Severance Plan expense is projected to decrease from $0.9 million in the historical test year to $0.3 million in the projected test year, based on actuarial projections provided by Aon.

Q49. How did you project the increase in the Company's Wellness Program expense?

A49. As referenced in the discussion of Active Healthcare expense, the Company has a Wellness Program designed to produce significant reductions in future active healthcare expense. This Wellness Program will result in an increase of Wellness Program expense from $3.8 million in the historical test year to $4.4 million in the projected test year (Exhibit A-13, Schedule C5.11, line 18).

Q50. Has the Commission addressed the reasonableness of the Wellness Program in its prior orders?

A50. Yes. The same Wellness Program was included in the Company's proposed revenue requirement in DTE Electric's most recent rate case. In response to the Attorney General's opposition to the inclusion of the increase in Wellness Program costs, the Commission concluded that it "supports wellness programs and the cost-efficiencies derived from supporting healthy employees and work environments" and adopted the Company's projections (Case No. U-20561, Order issued May 8, 2020, p. 202).

Q51. How have you projected the Company's Long-Term Disability Expense?

A51. Actual 2020 Long-Term Disability Expense is projected to increase from $1.1 million to $1.2 million during the projected test year based on the assumption that these costs will increase based on the labor escalation rate, escalated at the 3.0% annual labor cost rate recognizing that disability claims relate to employee labor.

Q52. What is the basis for the adjustments to the Supplemental Savings Plan costs for the projected test year?

A52. The decrease in the Supplemental Savings Plan (SSP) costs reflect an increase in the Company's matching contributions based on 3.0% projected salary escalations offset by a reduction in the expected earnings on the designated investments. Since

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the Company does not separately fund the Company's matches to the employees' contributions, the earnings and losses from the employees' directed investments is a cost incurred by the Company. The projection reflects an annual return on the investments consistent with the expected long-term return on investments used in the determination of the Company's pension costs in the projected test year. This results in SSP expense for the historical test year of $3.1 million being reduced to $2.7 million during the projected test year, which is primarily the result of actual investment returns in 2020 being higher than the 7.00% projected return.

Q53. What is the basis for the adjustments to the Deferred Compensation costs?

A53. Similar to the Supplemental Savings Plan, the Company's recorded costs are based on the return on the investment directives of the participating employees since the deferrals are not funded by the Company. The projected Deferred Compensation costs are based on the expectation that the designated investments will earn an annual return consistent with the expected return on assets for the pension plan. Thus, actual Deferred Compensation expense is projected to increase from $97,000 in the historical test year to $98,000 for the projected test year.

Q54. How have you developed the projections for the other items included in Other Benefits Costs on Exhibit A-13, Schedule C5.11?

A54. The ACA expense of $21,000 reflects the actual costs recognized for the Comparative Effectiveness Research Fee and, because the fee as approved in the ACA escalates at the overall national medical expenditures, is escalated at the medical trend used above, resulting in $24,000 of ACA expense for the projected test year. General Benefits Expense and Retirement Administration Fees are projected based on the actual amounts recorded in 2020 of $2.4 million and $0.4

million and escalated at the overall rate of inflation as measured by the Consumer Price Index through the end of the projected test year. This results in projected General Benefits Expense of $2.5 million and Retirement Administration Fees of $0.4 million.

Q55. What is the Company's total projected employee pensions and benefits expense for the projected test year?

A55. The total projected employee pensions and benefits costs of $129.9 million is reflected on Line 28 of Exhibit A-13, Schedule C5.11. After adjustments for the impact of the portion of these costs to be capitalized and transferred as well as the elimination of costs allocated to the Company's surcharge programs, as described by Witness Uzenski, results in net employee pensions and benefits expense of $109.2 million for the projected test year.

COVID-19 VACCINE MANDATE

Q56. Has the Federal Government announced any new vaccine mandates regarding COVID-19?

A56. Yes. On September 9, 2021, President Biden issued a multi-part action plan to combat COVID-19, which included an announcement that the Occupational Safety and Health Administration (OSHA) was to develop a rule that will require all employers with 100 or more employees to ensure their workforce is fully vaccinated or require any workers who remain unvaccinated to produce a negative test result on at least a weekly basis before coming to work. On November 5, 2021, OSHA issued an Emergency Temporary Standard that implemented these requirements.

Q57. How will the emergency OSHA rules impact the Company?

A57. It is unclear. Compliance with the emergency OSHA rules adopted on November 5, 2021, could be significant if implemented. For example, assuming 30% of the Company's approximately 7,000 employees remain unvaccinated and the cost of each COVID-19 test is $60, the Company would incur an annual cost of almost $7 million for the weekly testing of all unvaccinated employees. However, if laboratory diagnostics are required for these tests, the annual cost could easily triple to nearly $20 million. However, the emergency OSHA rules are also the subject of numerous actions in the Federal Court system regarding the legality and scope of the rules, which could result in the affirmation, modification or elimination of the emergency rules.

Simply stated, there is too much uncertainty regarding the actual costs that may be incurred by the Company of complying with OSHA emergency rules tests to develop a reliable estimate of the costs. Moreover, since the Company has excluded from the historical test year the non-recurring costs in 2020 related to COVID-19, including the related healthcare costs discussed above, there remains a risk that the Company will nevertheless incur costs related to COVID-19 in the future. This could include the costs of compliance with both existing and additional mandates issued by the Federal or Local governmental agencies, further actions taken by the Company to protect the health and safety of its employees and customers or increased healthcare costs that may arise from either additional COVID-19 variants or increases in the cost of vaccinations if current Federal subsidies are eliminated.

Q58. How do you propose this uncertainty be addressed?

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A58. Witness Uzenski proposes that the Company be authorized to establish a Regulatory Asset for the accumulation of the costs incurred by the Company in connection with the costs of both complying with President Biden's COVID-19 Action Plan and other COVID-19 costs the Company may incur in the projected test year.

LABOR COST ESCALATION

Q59. What annual labor cost escalation assumptions are appropriate for the projected test period?

A59. Annual labor cost escalation assumptions are required for both the Company's represented and non-represented employees. Based on existing Collective Bargaining Agreements, the Company is obligated to increase pay rates by approximately 3.0% annually through the term of the contracts. In addition to scheduled pay rate increases, the agreements also provide for progression increases for those employees that have not yet achieved the maximum pay rate for their positions.

Non-represented employee compensation is generally adjusted annually based on a review of pay practices of other employers, overall price level changes and internal pay equity. Pursuant to these reviews, the Company implemented base pay adjustments in March 2021 that resulted in an overall pay increase of about 3%, just as it was in 2020 and every year since 2010. In addition to the annual pay adjustment program, employees also receive pay increases based on promotions.

Based on the above, I have determined that annual escalations of 3.0% for 2021,

Line No.

2022 and 2023 are a conservative estimate of the Company's expected increase in its labor rates.

EMPLOYEE COMPENSATION

Q60. What is the Company's compensation philosophy and framework for non-represented employees other than Executives?

A60. Non-represented employees are those employees not covered by Collective Bargaining Agreements with union organizations, whereas Executives are generally defined as those at the Vice President level and above. DTE Electric's compensation philosophy is to provide pay programs that: 1) attract, retain, and motivate employees; 2) ensure that pay is externally competitive; and 3) differentiate total rewards based on both organizational unit and individual contributions and results.

At DTE Electric, total annual compensation for non-represented employees has two primary components: base pay and variable pay, as delivered through the Company's incentive compensation programs. Employee base pay is reviewed annually and adjusted (if appropriate) based on the position relative to what the external market pays for similar positions and individual performance. Variable pay is based on the achievement of Company, departmental and individual results reflecting a balance of customer, operational and, in limited instances, financial objectives. Variable pay consists of short-term incentive plans and a long-term incentive plan. Participation in the long-term incentive plan is open to all Managers, Directors and Executives as well as an additional 10% of non-represented employees that are eligible for discretionary awards.

Line No.

Q61. How does the Company's philosophy regarding incentive compensation compare with that of its peer group?

A61. Incentive compensation programs are a component of total compensation practices for the vast majority of energy companies for their non-represented employee population. Base pay is set lower than it otherwise would be because of the variable pay component. When considered holistically, the Company's base and variable pay plans provide a framework of market-based total annual compensation pay opportunities for non-represented employees. It is the total annual cash compensation, as represented by these two components, that prospective and current employees use to gauge whether DTE Electric's compensation is competitive with other potential employers.

Q62. How does the Company's non-represented compensation philosophy and framework provide benefits to customers?

A62. DTE Electric's compensation philosophy and framework provide a benefit to customers by attracting and retaining employees with the requisite skills and experience to ensure safe, reliable, and high-quality customer service delivery, and by recognizing and rewarding effective and efficient performance. A competitive compensation policy also serves to effectively retain employees, minimizing the risks and costs of high employee attrition. This philosophy directly benefits all customers by providing a high level of service at a competitive cost and provides incentives to focus future job performance on those activities that provide the most benefit to customers.

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Q63. What is the comparative market used by the Company to determine the external market for compensation?

A63. The comparative market for positions varies based on the specific job. Some jobs are compared to those in utilities of similar size (e.g., revenue, number of employees, etc.), other jobs to general industry located in Southeastern Michigan, and yet other jobs to general industry located within the United States. The relevant market will depend upon the requisite skills and abilities required of the job and the nature of the recruitment source. For example, the comparative market for an administrative assistant is the general industry within Southeastern Michigan while the comparative market for a manager of nuclear operations is utilities within the Midwestern United States (primarily), or within the entire United States (secondarily).

Q64. How is benchmark data obtained from the comparative market?

A64. The Company participates in and/or purchases published salary surveys from several different organizations. The surveys typically report median base salary, target incentives and median total cash compensation by job classification.

Q65. How are base salaries determined?

A65. Base salaries are targeted around the median base salary levels of the comparative market as adjusted for differences in company size and scope where appropriate. All non-executive positions are placed in a salary zone based on external benchmarking. The mid-point of the salary zone is based on the market median for comparable work in comparable companies. A range is provided above and below the midpoint to allow for differentiation based on applicable skills and experience, as well as demonstrated performance. The ranges are reviewed periodically to ensure they remain competitive in the external market.

Q66. Does the Company benchmark the variable component of compensation?

A66. Yes. The Company reviews several surveys that provide information on a number of variable pay indices. In addition, the surveys report data for employee groupings like exempt employees, non-exempt employees, managers, and executives.

COMPETITIVE COMPENSATION ANALYSIS

Q67. Has the Company prepared an analysis of its compensation practices relative to the market medians?

A67. Yes. DTE Electric has performed an analysis of virtually all incumbent salaries as of December 31, 2020, showing that DTE's compensation practices are competitive with market medians. Exhibit A-21, Schedule K1 reflects a summary of the market median for all DTE Electric positions for which corresponding positions have been identified, other than those employees covered by collective bargaining agreements. In addition, Exhibit A-21, Schedule K1 reflects those positions at DTE LLC that primarily support DTE Electric. Exhibit A-21, Schedule K1 reflects employee compensation information organized based on Career Family classifications used by DTE Electric. A Career Family is a grouping of jobs based on similar skill requirements and job content in a specialized discipline (i.e., Finance, Engineering, Information Technology, etc.) that may or may not fit into a business unit organizational structure. For example, Engineering or Finance Career Families could exist in several organizational units.

Q68. Why have you excluded from this analysis employees covered by collective bargaining agreements?

A68. Compensation levels for unionized employees are determined through a negotiated process, which involves a variety of work rules and benefit related issues, rather than determined strictly through market analysis. Moreover, the specialized skills and experience required by many of the positions are not readily comparable to other positions in the local market. Thus, a comparison of pay levels for those employees covered by collective bargaining agreements is not useful in this context.

Q69. What conclusions do you draw from Exhibit A-21, Schedule K1?

A69. In summary, Exhibit A-21, Schedule K1 demonstrates that the weighted average of the annual base compensation for all positions with incumbents as of December 31, 2020, with available position matches was a mere 0.1% more than the average of median market base compensation. Plus, such analysis further demonstrates that total cash compensation for all positions with incumbents as of December 31, 2020, with available position matches was 0.8% less than the average of median market for total cash compensation. This analysis concludes that the Company's total compensation is insignificantly different from the market medians and confirms that the Company's compensation practices are consistent with the Company's compensation policy to pay employees near the market median for comparable positions on a total cash compensation basis. Moreover, a comparison of the Company's base salaries, which excludes short-term incentive compensation, to the market medians for total cash compensation, which is inclusive of short-term incentive compensation, shows that in the absence of the Company's short-term incentive compensation programs, the Company's pay would be 11.5% less than the market medians.

Q70. How was the market median for the positions determined?

A70. As described above, the Company subscribes to several compensation survey providers that create comprehensive databases of job descriptions that enables the Company to match the job requirements, including education, expertise and experience of existing positions with market surveys. After matching job positions are identified, actual base and total compensation ranges are developed from the salary survey database. The information on Exhibit A-21, Schedule K1 was derived from the Company's compilation of the compensation for positions with an incumbent as of December 31, 2020.

Q71. What proportion of DTE Electric's total employee population as of December 31, 2020, is reflected in this analysis?

A71. This analysis includes 99.1% of the employee population as of December 31, 2020, at DTE Electric, as well as DTE LLC employees that provide supporting services to DTE Electric, but exclusive of those employees represented by collective bargaining agreements.

Q72. What is included in the total cash compensation amounts?

A72. Total cash compensation reflects base pay as of December 31, 2020, and the Target payout levels for those employees eligible to participate in the Company's short-term incentive compensation programs. Although the analysis on Exhibit A-21, Schedule K1 does not reflect the value of the Company's Long-Term Incentive

Line No.

Plan, as it is primarily for executive level positions, a separate analysis of executive compensation prepared by Aon, which is inclusive of long-term plans, shows that total compensation is equal to the median of the Company's peer group, as discussed in more detail below.

Q73. Has the Company had any independent experts on compensation review the Company's analytical techniques?

A73. Yes. Independent assessments by Aon have concluded that the Company uses best practices in sourcing the market pay data and developing estimated market values.

EXECUTIVE COMPENSATION

Q74. How does the compensation program for Executives differ from that for non-executives?

A74. The compensation program for Executives differs in three respects. First, the comparative market for compensation benchmarking is defined as a specific group of peer companies from which comparative data are analyzed through a custom study performed every two years. Second, a higher proportion of Executives' compensation is delivered in the form of variable pay. The third way in which the Executive compensation program differs is with respect to governance. The compensation programs for Company Executives must be approved by the Organization and Compensation Committee of the DTE Energy Board of Directors.

Q75. What is the comparative market for Executive compensation?

A75. The comparative market for Executive compensation consists primarily of utilities (including utility holding companies), broad-based energy resource companies and

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certain non-energy related companies selected on the basis of revenues, financial performance, geographic location and availability of compensation information.

Q76. What are the key components of the Executive Compensation Program?

A76. The key elements of the Executive Compensation Program are base salary and variable pay (annual incentive plan and long-term incentive awards).

Q77. How are Executive base salaries determined?

A77. Executive base salaries are targeted around the median of the comparative market. Appropriate methods of measurement are used to take into account differences in company size and scope. In addition, midpoints are established for those Executives whose jobs cannot be easily matched in the comparative market. These midpoints are designed to allow adequate differentiation for (i) individual potential, (ii) contributions made, and (iii) the length of time the Executive has been in his or her position and are assessed periodically to keep pace with market movement.

INCENTIVE COMPENSATION

Q78. What are you proposing regarding the level of incentive compensation expense to be included in the Company's revenue requirement?

A78. I am proposing that projected incentive compensation expense of $63.8 million related to the Company's short-term and long-term incentive compensation plans be included in the revenue requirement adopted by the Commission in this proceeding, as described in more detail below.

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Q79. Is the Company requesting recovery in rates for all incentive compensation expenses?

A79. No. The Company has excluded $10.1 million for DTE Energy's Top Five Executive Officers. This exclusion is reflected on Exhibit A-3, Schedule C19 as supported by Witness Uzenski and has been excluded from the table reflected in the response to Q101.

Q80. What is the basis for your proposed inclusion of $63.8 million of incentive compensation expense in the Company's revenue requirement?

A80. In summary, my proposal to include the Company's projected incentive compensation expense, exclusive of the portion related to the Named Executive Officers, is based on the prevalence of incentive compensation programs and the resultant need for the Company to have total compensation programs that enable it to be competitive with other employers.

Q81. Are incentive compensation programs a typical element in compensation at other companies?

A81. Yes. According to a 2021 study published by WorldatWork and Compensation Advisory Partners, the vast majority of companies have both short-term and long-term incentive programs. (Incentive Pay Practices: Publicly Traded Companies, July 2021, WorldatWork and Compensation Advisory Partners). Moreover, a 2018 study by Aon of U.S. Salary Increases shows that 90% of Power and Gas Service providers utilized broad-based incentive compensation programs.

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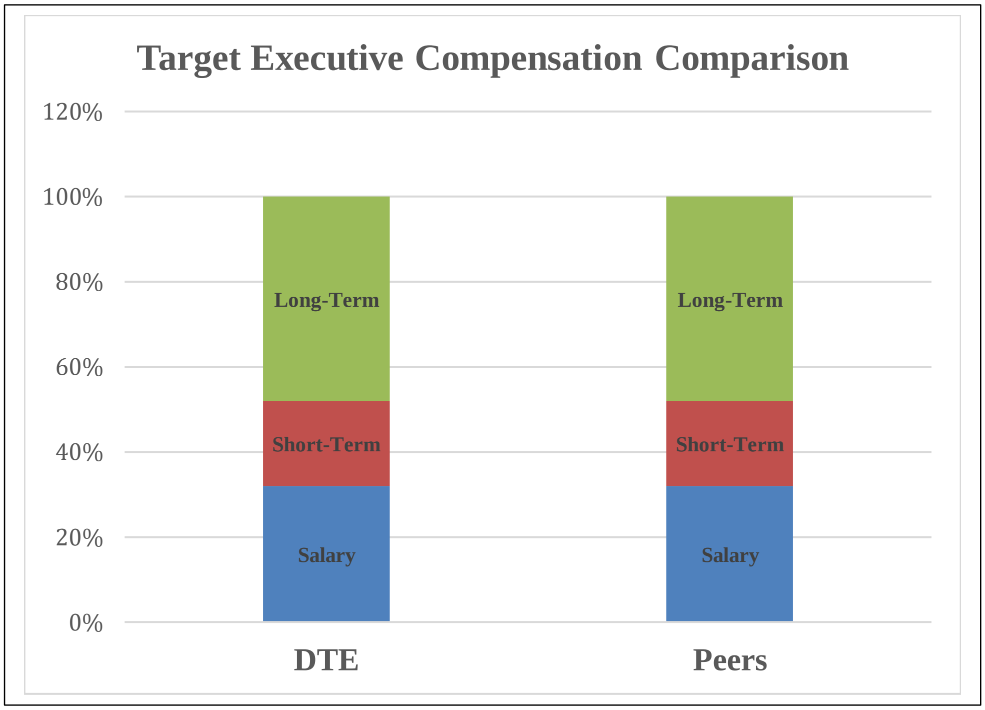
Q82. Does the Company's incentive compensation program result in unreasonable compensation?

A82. No. As explained above, the Company benchmarks its total compensation for both Executive and non-executive employees against relevant peers, inclusive of incentive compensation, establishing a mid-point salary range based on the median market level. Moreover, based on a recent survey by Aon, the total compensation of DTE Energy's Executives is equal to the median of its peers based on Target level performance, inclusive of the long-term incentive compensation. The Company's incentive compensation programs are merely a component of the total compensation policies required for the Company to be competitive with its peers, rather than a supplement. Indeed, in the absence of the incentive compensation programs, total compensation for DTE Energy's Executives would be substantially less than its peers, since about 70% of total compensation is delivered through variable pay programs, by both DTE and its peers.

Q83. How do the components of the Company's total compensation practices compare to the Company's peers?

A83. Based on the Aon survey referenced above, a comparison of the relative magnitude of the Company's salary, short-term and long-term pay components for Executives to the 50th percentile of its peers is reflected in Table 2.

Table 2



Q84. What are the specific components of the Company's incentive compensation programs?

A84. The Company has incentive compensation plans for both its Executive and all other non-represented employees. Short-term incentive plans are provided through the Annual Incentive Plan (AIP) and Rewarding Employees Plan (REP). Additionally, a multiple year incentive plan, which is available to all managers and above and up to 10% of other eligible non-represented employees, is provided through the Long-Term Incentive Plan (LTIP).

Q85. What is the AIP?

A85. The AIP is a short-term variable pay program available to senior management level employees to motivate performance. The 2021 AIP measures and weightings for DTE Electric, other than Nuclear Generation, DTE Nuclear Generation, and DTE

LLC are reflected on Exhibit A-21, Schedules K2 through K4. For each measure, a Target is established for which a 100% payout will be earned. Performance less than Target but above a minimum Threshold result in a payout between 25% of Target and Target, and performance up to the Maximum level results in a payout of up to 175% of Target for the AIP.

Q86. Which employee classification is eligible to participate in the AIP?

A86. All Executive level employees, generally Vice President and above, and Directors participate in the AIP. All other non-represented employees are eligible to participate in the REP.

Q87. What are the components of the REP?

A87. The REP is identical to the AIP except that Threshold performance is at 50% of Target and the Maximum performance payout is 150% of Target. The 2021 REP measures and weightings are reflected on Exhibit A-21, Schedules K2 through K4. The Gallup survey of employee engagement measure is excluded from the REP in recognition that the Company's leadership is responsible for providing an environment of high employee engagement.

Q88. What are the categories of measures included in the AIP and REP?

A88. There are four categories of measures in both the AIP and REP. Specifically, Financial Performance, Customer Satisfaction, Safety & Engagement, and Operating Excellence.

Q89. What are the financial measures included in the AIP?

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A89. There are three financial measures for DTE Electric employees that are designed to create a clear line of sight for all employees to focus on operating excellence by rewarding employees when the Company is successful.

1) DTE Electric Operating Earnings objective is based on the Company realizing the authorized return on equity by the Commission in its Order in Case No. U-20561.

2) DTE Electric's Cash from Operations is similarly based on the authorized return on equity but reflects the higher capital expenditures arising from the significant investments required to upgrade DTE Electric's system. The inclusion of a cash flow measure recognizes the importance of DTE Electric maintaining a high credit rating to allow continued access to the capital markets at reasonable costs and terms to ensure proper capital investment to continue to serve our customers.

3) DTE Energy's Earnings per Share measure is based on the high-end of 2021 earnings guidance.

Nuclear Generation Financial Performance measures consist of DTE Electric Operating Earnings and Nuclear Generation Operation and Maintenance Expense. The Financial Performance measures for DTE LLC reflect DTE Energy's Operating Earnings per Share and Cash from Operations.

Q90. What are the Customer Satisfaction measures?

A90. There are two customer satisfaction measures that are intended to focus employees on improving the experience that our customers have in their interactions with the Company.

1) The Net Promoter Score is a measure of the extent to which customers are likely to recommend the Company to their friends and colleagues .

2) The MPSC Customer Complaints measure represents the number of formal complaints made to the MPSC regarding DTE, as reported to the Company by the MPSC.

Q91. What are the Safety & Engagement measures?

A91. The three Safety & Engagement measures encompass employee engagement as measured by the Gallup survey and two employee safety related measures.

The Gallup measure of Employee Engagement is reflective of the direct correlation between the level of active employee engagement and the performance of an organization. The 2021 Target of 4.32 is based on continued top decile performance compared to Gallup's total database and actual results will be determined based on a survey of employees by Gallup. Employee Engagement is a statistically significant measure of the level of commitment employees have to an organization's success and is not merely a measure of employee satisfaction.

DTE Electric has two safety related measures.

1) Recordable injuries per 100 employees divided by the actual number of hours worked, as defined by the Occupational Safety and Health Administration (OSHA). This is a standard measure of safety performance used nationwide. The measure is intended to create a heightened focus on the importance of safety in the workplace.

2) OSHA Days Away, Restricted or Transferred (DART) rate. This measure is calculated by taking the number of qualifying injuries per 100 employees divided by the actual number of hours worked.

Q92. What are the Operating Excellence measures for 2021?

A92. DTE Electric has four Operating Excellence measures that reflect specific operating priorities for 2021 to motivate the achievement of certain operating objectives important to the Company, its customers, and the Commission.

1) The Fossil Power Plant Reliability measure reflects the percentage of time the plants are not available for power production due to a random outage, referred to as the Random Outage Factor (ROF). The 2021 Target is 6.8%, which represents better than first quartile performance of the industry benchmark, as compiled by the North American Electric Reliability Corporation.

2) One measure of Electric Distribution Reliability is average number of minutes per interruption for customers experiencing an interruption when there is not a declared storm (Blue Sky Customer Average Interruption Duration Index (CAIDI)).

3) The second measure of Electric Distribution Reliability is the System Average Interruption Duration Index (SAIDI) exclusive of Major Event Days (MEDs).

4) DTE Electric's Operating Excellence measures also include the Nuclear On-Line Unit Capability Factor (UCF), which is described below.

Line No.

Q93. What are the operating measures applicable to the Nuclear Generation business unit?

A93. Nuclear Generation has three Safety and Engagement related measures and four Operating Excellence measures.

Q94. What are Nuclear Generation's Safety and Engagement related measures?

A94. In addition to Employee Engagement, as measured by Gallup surveys, and the OSHA Recordable Incident Rate, which have been described in the context of DTE Electric, Nuclear Generation also uses the annual Total Industrial Safety Accident Events (TISA Events), which is a nuclear industry measure that is aligned with the Institute of Nuclear Power Operations, in lieu of the DART rate. The Threshold is one incident and the Maximum is zero.

Q95. What are the Operating Excellence measures related to Nuclear Generation?

A95. Nuclear Generation has four Operating Excellence measures.

The first relates to On-Line UCF, which measures the percentage of time that Fermi 2 is available to generate power, exclusive of planned outages. The 2021 Target of 98.5% represents a performance level that is within the second quartile of the Company's peers.

The three additional Operating Excellence measures for nuclear generation include a measure Operational Focus and indices that encompass Work Management and Radiation Protection.

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Q96. Are there other AIPs and REPs that impact DTE Electric's expenses?

A96. Yes. In addition to the DTE Electric and Nuclear Generation measures described above, there are also separate AIP and REP measures for corporate staff employees at DTE LLC that provide services to all DTE Energy business units. The measures of the DTE LLC reflect certain DTE Electric and Nuclear Generation measures, as well as measures related to DTE Gas. The specific measures related to DTE Electric and Nuclear Generation are reflected on Exhibit A-21, Schedule K-4.

Q97. What is the Company's Long-Term Incentive Plan?

A97. The LTIP provides the opportunity for certain individuals to receive retention-oriented or performance-based rewards delivered via shares of DTE Energy common stock, either through Restricted Stock or Performance Shares. While the Restricted Stock generally vests based on the employees' tenure, the final payout of Performance Shares is based on the achievement of multiyear performance objectives. Currently 30% of the value of awards is through Restricted Stock and 70% through grants of Performance Shares for executives and directors, while 100% of the awards to individuals below Director-level are through Performance Shares. The objective in granting shares through this program is to both motivate superior results as well as provide a means to retain key employees and is consistent with the practices of a vast majority of surveyed companies, as reflected in the WorldatWork and Compensation Advisory Partners study referenced in Q81.

Q98. What are the performance share measures used in the LTIP?

A98. The measures are shown on Exhibit A-21, Schedule K5.

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Q99. What is the rationale for the use of these measures?

A99. These measures reflect the long-term financial performance of DTE Energy and are intended to motivate employees of the individual operating companies, such as DTE Electric, to keep in mind the role of their own contributions to the overall long-term success of DTE. Accordingly, the predominate measure for DTE Electric and DTE LLC (80% for both) is the total return to DTE Energy shareholders (i.e., capital appreciation and dividends) relative to a group of peer companies over the next three years. This three-year focus is designed to motivate decisions and actions that produce sustainable benefits rather than short-term actions that may entail long-term risks. The second financial measure included in the LTIP that contributes 20% to the weighting for DTE Electric and DTE LLC is the actual DTE Electric Average Return on Equity over a three-year period. The focus on DTE Electric's three-year return on equity provides a longer-term emphasis that encourages sustained performance.

The LTIP also includes two operating measures for Nuclear Generation that relate to a standard industry index measuring nuclear power plant performance and the Nuclear On-Line UCF, which have weightings of 60% and 20% respectively. The third Nuclear Generation measure relates to DTE Energy's total return to shareholders and is weighted 20%.

Q100. What is the basis for the costs of the LTIP?

A100. The LTIP costs incurred in 2020 pertain to the grants of Performance Shares and Restricted Stock. The expense related to the Restricted Stock is not conditioned on any Company performance measures but rather is exclusively based on the number of shares granted at the date of grant. In contrast, Performance Shares expense is

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based on the achievement of the predetermined performance objectives. The recognized cost of Performance Shares is based on the number of shares granted at the market price of DTE Energy's common stock at the date of grant but with adjustment in the number of shares based on actual performance. Witness Uzenski describes the adjustment to the actual 2020 LTIP expense to normalize for the impact of changes in DTE Energy's stock price recognized in 2020.

Q101. What is the incentive compensation expense if all the Operating Targets are achieved?

A101. The net expense to DTE Electric in the projected test period of the Company achieving all of its Targets for the incentive compensation plans, exclusive of the expense related to the Named Executive Officers, is $63.8 million. The table below summarizes the expense for the projected test period by the nature of the plans, the classification of the employees eligible and the basis of the metrics used.

Table 3

	LTIP	AIP	REP	Total
		(000's Omitted)		
Financial				
DTE Electric	$6,492	$744	$7,177	$14,413
Nuclear Gen	266	89	836	1,191
DTE LLC	15,229	4,764	5,876	25,869
	21,987	5,598	13,888	41,473
Operating				
DTE Electric	0	657	6,335	6,992
Nuclear Gen	1,064	234	3,027	4,326
DTE LLC	0	5,137	5,834	10,972
	1,064	6,029	15,196	22,290

Total				
DTE Electric	6,492	1,402	13,511	21,405
Nuclear Gen	1,331	324	3,863	5,517
DTE LLC	15,229	9,901	11,710	36,841
	$23,052	$11,627	$29,084	$63,763

Q102. Why do the expenses for DTE LLC represent a majority of the variable compensation expenses?

A102. DTE LLC provides a variety of administrative and other services that are common to both DTE Electric and DTE Gas for which the costs are billed to the operating companies, as explained by Witness Uzenski. In addition, DTE LLC employs all of the Executives of DTE Energy, including the Executives of DTE Electric.

Q103. How have you reflected the Operating Excellence measures related to DTE Gas in the AIP and REP for DTE LLC?

A103. While the AIP and REP expenses allocated to DTE Electric in the historic period from DTE LLC include some measures related to DTE Gas, the AIP and REP weightings for DTE LLC have been adjusted to exclude the measures specifically related to DTE Gas.

Q104. Do the amounts in Table 3 reflect that a portion of the Company's incentive compensation costs are capitalized?

A104. Yes. The amounts in Table 3 are net of the portion of AIP and REP costs related to operating measures that will be capitalized. The LTIP amounts in Table 3 are the total costs, with no reduction for the portion capitalized. These capitalization assumptions are in recognition of the Commission's exclusion from Net Plant of

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the incentive costs capitalized related to financial measures in its Order in Case No. U-20561, as more fully described by Witness Uzenski.

Q105. Are all incentive compensation costs dependent on the Company's financial or operating performance?

A105. No. As described earlier, a portion of the DTE Energy shares granted under the LTIP are in the form of Restricted Stock. Unlike the Performance Shares, the cost of Restricted Stock is not variable based on either the Company's financial or operating performance. The only contingency is that the employee forfeits the Restricted Stock if they leave the Company, other than through retirement or the event of death or disability of the employee. While Restricted Stock grants are made under the LTIP, they are not regarded as incentive compensation. Accordingly, the expense of $5.9 million related to Restricted Stock is excluded from Table 3.

Q106. Has the Commission provided any criteria for the inclusion of incentive compensation expense in the Company's revenue requirements?

A106. Yes. The Commission has indicated in all its recent Orders that address the topic of incentive compensation programs that recovery of such expenses is dependent on a demonstration that the programs provide benefits to customers in excess of the expense.

Q107. Have you performed an analysis of the customer benefits of the Company's incentive compensation programs?

A107. Yes. The Company performed a comprehensive analysis of the customer benefits that would be derived from the achievement of the metrics included in the Company's incentive plans relative to their expense. This analysis, as reflected on Exhibit A-21, Schedule K6, demonstrates that the total calculated customer benefit of $105.6 million exceeds the total incentive compensation expense of $63.8 million by $41.8 million.

Q108. How did you calculate the interest cost savings from the retention of the Company's existing debt ratings?

A108. The primary benefit of achieving the Cash from Operations measure is the Company maintaining its BBB+ debt rating from Standard & Poor's and comparable ratings by the other major debt rating firms. The current yield spread between utility A rated bonds compared to BBB rated bonds is 22 basis points. Based on the long-term debt included in the capital structure sponsored by Company Witness Vangilder, a downgrade in the Company's credit rating would increase the Company's annual interest costs by $18.5 million.

Q109. How have you quantified the benefits of the Nuclear Generation related operating measures included in the LTIP?

A109. The benefits of two operating measures related to Nuclear Generation are based on the achievement of Target performance for the Nuclear On-Line UCF, the means of quantification of which is described below in the discussion of the Operating Excellence measures. The customer benefits from achieving Target UCF performance, which represents the most quantifiable component of the Nuclear

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Generation measures, is allocated to the individual measures in proportion to the costs of each measure.

Q110. What is the net customer benefit of the LTIP measures?

A110. As reflected on Exhibit A-21, Schedule K6, the quantifiable benefits of the operating LTIP measures are $2.5 million compared to the cost of the LTIP operating measures of $1.1 million, for a net customer benefit of $1.4 million. While customer benefits of the LTIP financial measures are not readily quantifiable, customers do realize a benefit from DTE Electric and DTE Energy being financially healthy with access to the capital markets.

Q111. How are the benefits of the AIP and REP reflected on Exhibit A-21, Schedule K6 computed?

A111. The benefits of the measures are computed based either on the avoided costs to the Company, which results in lower future revenue requirements, or based on the value to customers of improved performance. The reference points to determine improvement are, in most instances, based on the Company's actual performance in the 2020 historical test year, but when 2020 results are not representative, a five-year average is used. In those instances in which the Company's Targets are based on superior performance relative to peers, then measures of peer performance are used. The benefits of achieving Target performance are allocated between the AIP and REP components based on the relative AIP and REP expense for each measure.

Q112. How did you quantify the benefit of achieving Target performance levels in the Customer Satisfaction measures?

A112. The benefits of achieving the 2021 Target of 45% Net Promoter Score (NPS) are based on the expectation that improvements in the NPS score will result in fewer customer calls. The 2021 Target of 45% represents a 5% improvement relative the 2020 actual NPS and is expected to produce $5.5 million of customer benefits based on avoided Company costs and customer costs.

The customer benefits of attaining Target performance for MPSC Customer Complaints measure is based on the avoided costs to both the Company and its customers based on the reduced time spent by employees and customers resolving complaints for a total savings of $0.2 million.

While the total quantified benefits of $5.7 million related to the Customer Satisfaction measures are slightly less than the related expense, there can be little doubt that an emphasis among the Company's employees on improving the experiences customers have with the Company results in additional significant non-quantifiable benefits to both customers and the Commission.

Q113. How did you determine the benefits of the Employee Engagement measure?

A113. The quantifiable benefits of a highly engaged workforce are based on three critical dimensions identified by Gallup: absenteeism, productivity, and safety incidents. According to Gallup, a 0.1 improvement in the grand mean will result in a 3.1% reduction in absenteeism, a 1.8% increase in productivity and a 3.8% reduction in safety incidents. Compared to median level of Gallup survey results for other companies, achievement of the 2020 Target Gallup survey results will generate O&M savings at DTE Electric of $4.1 million, inclusive of savings allocated from LLC and net of the savings capitalized.

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Q114. What are the expected benefits of the Company achieving Target level performance regarding the OSHA Recordable Incident Rate (RIR)?

A114. The benefits of achieving the OSHA Recordable Incident Rate (RIR) and the Nuclear Total Industrial Safety Accident Rate goal are based on the estimated direct costs of non-fatal incidents of $41,000, as developed by OSHA, and a study by Liberty Mutual that estimates the indirect cost of an OSHA recordable is about 3.0 times the direct costs, results in a total cost of $169,000 per incident, in current dollars. Based on Target level performance relative to the 75th percentile performance of the Company's peer group results in an estimated benefit of $4.7 million, net of the savings capitalized. Because the benefits of achieving the OSHA RIR Target are similar to the OSHA DART and TISA Events, the benefit is allocated in proportion to the costs of each related measures.

While the quantified savings of the safety related metrics are less than the related costs, much like the customer service-related measures, the benefits of maintaining an organizational focus on the safe operation of the Company's system for the benefit of its employees, customers, and the communities where the Company operates are undoubtedly substantial.

Q115. How did you quantify the savings related to improvements in distribution system reliability?

A115. The benefit of achieving the Blue Sky CAIDI of 103 minutes is based on comparing the 2021 Target to the five-year average of Blue Sky CAIDI of 124 minutes, which represents a reduction of 21 minutes, or almost 17%. The derivation of the benefits to customers was determined based on the Interruptions Cost Estimation Calculator

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as developed by Nexant, Inc. and the Lawrence Berkeley National Lab. A reduction of 21 minutes in the Blue Sky CAIDI produces an annual customer benefit of $41.0 million. The benefits of achieving Target performance in the Blue Sky CAIDI measure have been allocated equally between the Blue Sky CAIDI and SAIDI exclusive of MEDs measures due to the close relationship of each of these measures to distribution system reliability.

Q116. How did you quantify the benefits of the Fossil Power Plant Reliability measure?

A116. The benefit of the Fossil Power Plant Reliability measure reflects the impact of decreasing the ROF from a five-year average of about 7.8% to the 2021 Target of 6.8%. The savings computed reflect the impact of the increases in power generation relative to the avoided market energy purchases and increased capacity value. This produces annual savings of $1.6 million.

Q117. What are the benefits of an increase in the Nuclear Power Plant Reliability?

A117. The benefits of an increase in the Nuclear Power Plant Reliability reflect an increase from the On-Line UCF at Fermi 2 from the five-year average of 92.8% to the 2021 Target of 98.5%. Because Fermi 2 has the lowest marginal costs of production within the DTE Electric fleet, increased utilization has a significant impact on the overall cost of power generation. The savings computed are based on the differential between Fermi 2's marginal fuel costs and the average market price of avoided energy purchases combined with increased capacity value for a total annual savings of $16.7 million. These savings are allocated to the Nuclear related

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operating measures included in the LTIP as well as to the AIP and REP measures in proportion to the costs of each measure.

Q118. Have you quantified any additional savings related to the other Nuclear Generation measures included in the AIP and REP and the Nuclear Industry Index included in the Nuclear LTIP?

A118. No. The On-Line UCF measure represents the only quantifiable benefits of the Company meeting its Target performance levels for Fermi 2. While there is indisputable value in the various specific measures within the other Nuclear measures, the benefits of Fermi 2 achieving its Target On-Line UCF level has been attributed to these matrices and the Nuclear Industry Index.

Q119. What is your conclusion regarding the cost effectiveness of the Company's incentive compensation plans?

A119. While not every individual measure has quantified benefits in excess of the incentive compensation expense of the related measure, it is clear that in aggregate, the quantified customer benefits of the Company achieving Target performance levels are substantially greater than the related expense.

Because the Company's overall employee compensation approximates the market, inclusive of incentive compensation and the quantified benefits exceed the projected incentive compensation expense, the Company's total incentive compensation expense should be included in the revenue requirement adopted by the Commission in this proceeding as a reasonable and prudently incurred expense.

Q120. Has the Commission recently addressed the issue of the inclusion of incentive compensation expense in a utility's revenue requirement?

A120. Yes. In its Order in DTE Gas Company's most recent rate case the Commission included only 20% of the expense related to the operating measures and concluded that incentive compensation expense related to financial measures should not be included in DTE Gas's revenue requirement (Case No. U-20940, Order issued December 9, 2021, pp 162-164).

Q121. Do you agree with the Commission's exclusion of 80% of the incentive compensation expense related to the operating measures?

A121. No. The Commission adopted the Attorney General's proposal to include only 20% of the incentive compensation expense related to the operating measures based on an analysis described as being a five-year average of Target and above performance. However, the Attorney General's proposal was incorrect because the 20% failed to include the operating measures that were at the Maximum performance level. The actual five-year average of operating measures in which performance was Target and above was about 50%. More importantly, the Commission's adoption of the Attorney General's proposal failed to recognize that although certain measures may produce results less than Target, other measures can produce results that are greater than Target. This is important because the AIP provides for scaled payouts between 50% and 175% of Target and the REP provides for scaled payouts between 25% and 150% of Target for performance between Threshold and Maximum. Exclusive reliance on the number of measures at Target represents a binary model that is based on a pass/fail test that fails to recognize the gradients of performance between the Threshold and Maximum performance levels and the resulting impact on the Company's incentive compensation expense.

Q122. Have you computed the actual operating performance levels for the most recent five-year period that recognizes the gradients of performance between Threshold and Maximum levels?

A122. Yes. Exhibit A-21, Schedule K7, reflects the actual operating measures performance for the years 2016 through 2020 for both the AIP and REP for all employee groups. Exhibit A-21, Schedule K7 provides the actual performance relative to not only Target levels, but also in relation to Threshold and Maximum levels.

Q123. What conclusions do you draw from Exhibit A-21, Schedule K7?

A123. This exhibit shows that from 2016 through 2020, the AIP had achieved performance in the operating measures of between 87.4% to 125.4% for an average over that period of 100.9% whereas the REP had achieved performance of between 77.8% and 107.6% for an average of 87.5%. The combined five-year average for both the AIP and REP is 94.2%. These variations in actual performance in the operating measures reflect the ambitious goals that are set each year to motivate ever improving operating performance because, in most instances, the performance Targets are increased each year from the prior year.

Q124. Do these percentages vary from the five-year average of operating performance when the average of the measures at Target and above performance is compared to the total measures?

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A124. Yes. They vary significantly. The five-year average of measures with results at Target and above relative to total measures for the AIP is 63.1% and for the REP is 59.6%, for a combined average of 61.3%, as reflected on lines 50 though 58 of Exhibit A-21, Schedule K7.

Q125. Is the use of the average based on weighted performance of 94.2% a more accurate measure of the level of incentive compensation expense that the Company will incur in the projected test year than the simple average of 61.3%?

A125. Yes. Due to the scaled payouts for performance between Threshold and Maximum, as described above, the use of the weighted performance average is more indicative of the incentive compensation expense related to the operating measures the Company will incur in the projected test year. Based on five-year average of the weighted performance of 94.2%, it is reasonable to include 100% of the incentive compensation expense related to the operating measures. Reliance on the weighted measures is also consistent with all Commission Orders in DTE Electric and DTE Gas rate cases that addressed this identical issue prior to the Order in Case No. U-20940.

Q126. Do you agree with the Commission's conclusion regarding the financial measures?

A126. No. The Commission apparently rejected the inclusion of the incentive compensation expense related to the financial measures based, in part, by opining that "DTE Gas's mere contention that customers receive benefits from well-compensated employees is insufficient to demonstrate that incentive compensation specifically tied to financial performance does not primarily benefit shareholders or that such benefits to ratepayers are commensurate with the proposed expense".

I disagree with the Commission's conclusions for two reasons. First, because the total quantified benefits of all measures exceed the aggregate expense, it is proper to include all incentive compensation expense, including the portion related to the financial measures. Second, as demonstrated earlier in my testimony, the Company's total compensation, inclusive of incentive compensation, is well aligned with market medians. That alignment in compensation is required to enable the Company to attract and retain qualified employees. The need to have competitive compensation practices has never been more important than in today's environment in light of the increased challenges of both keeping existing and hiring new employees. By focusing on the individual components of the Company's compensation programs, including incentive compensation, the importance of the overall reasonableness of the Company's compensation costs is lost.

Q127. Does this complete your direct testimony?

A127. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JEFFREY C. DAVIS

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Jeffrey C. Davis (he/him/his). My business address is: 6400 North Dixie Highway, Newport, Michigan, 48166. I am employed by DTE Electric Company at the Fermi 2 Nuclear Power Plant as Manager of Nuclear Strategy and Business Support.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I graduated from the University of Michigan with bachelor's degrees in nuclear engineering and radiological sciences (NERS) and engineering physics. I have also earned a master's degree and doctorate in NERS from the University of Michigan. I am a member of the American Nuclear Society.

Q4. What is your DTE Electric work experience?

A4. I have been employed by DTE Energy since 2008. Prior to my current position, I was a principal financial analyst with responsibility for budgeting, forecasting, and reporting operations and maintenance (O&M) and capital expenditures for the Nuclear Generation organization.

Q5. What is your current position?

A5. In 2015, I was promoted to the role of Manager – Nuclear Strategy and Business Support with responsibility for developing the strategic financial plan and goals for the Nuclear Generation organization.

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Q6. Have you previously been involved in DTE Electric general rate case filings?

A6. I was the DTE Electric witness in support of nuclear fuel expenses, nuclear O&M expenses, nuclear capital expenditures and the nuclear surcharge in the Company's most recent general rate cases: Case Nos. U-20162 and U-20561. I was also the DTE Electric witness in support of nuclear generation for DTE Electric's Power Supply and Cost Recovery (PSCR) Reconciliation Case Nos. U-20203 and U-20528. In addition, I have provided support to other DTE Electric witnesses in support of nuclear fuel expenses, nuclear O&M expenses and nuclear capital expenditures in the following DTE Electric rate cases: Case Nos. U-16472, U-17767, U-18014 and U-18255.

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Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to discuss and support the reasonableness of the Company's actual nuclear O&M and capital expenditures for the 12-month historical test period ended December 31, 2020. I will also discuss and support the reasonableness of the projected nuclear O&M and capital expenditures for the bridge forecast period and the 12-month projected test period ending October 31, 2023. In addition, I will discuss and support the reasonableness of the projected Nuclear Surcharge for the projected test period ending October 31, 2023.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.3	Projected Capital Expenditures - Nuclear Production Plant & Nuclear Fuel
A-13	C5.3	Projected Operation and Maintenance Expenses - Nuclear Power Generation
A-13	C5.16	Nuclear Power Generation - Projected PERC O&M Expenditures
A-20	J1	Proposed Nuclear Surcharge Projected Test Period – 12 Months Ending October 31, 2023
A-20	J2	DTE Electric Nuclear Decommissioning Study for the Fermi 2 Power Plant

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

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Q10. How do you plan to proceed with your testimony?

A10. I will begin my testimony with the Nuclear Generation capital expenditures; discussing and supporting the actual capital expenditures for the historical test year ended December 31, 2020, the projected capital expenditures for the bridge forecast period and the 12-month projected test period ending October 31, 2023. I have divided my Nuclear Generation capital expenditure discussion into four sections of expenditures: Routine and Small Projects, Non-Routine and Large Projects, Nuclear Fuel, and Allowance for Funds Used During Construction (AFUDC).

I will then discuss and support the actual O&M expenses for the historical test year ended December 31, 2020 and the forecasted O&M expenses for the 12-month projected test period ending October 31, 2023 for Nuclear Generation. I have divided the Nuclear Generation O&M expenses discussion into three sections: rate case adjustments, adjusted historical test period and projected adjustments.

I will then discuss and support the Nuclear Surcharge for the 12-month projected test period ending October 31, 2023 for Nuclear Generation.

The Fermi 2 Power Plant is licensed by the Nuclear Regulatory Commission (NRC) to operate through 2045. The capital and O&M expenditures discussed for the historical and projected test periods throughout my testimony reflect appropriate measures to ensure safe and reliable operation of the Fermi 2 Power Plant through 2045.

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Nuclear Generation Capital Expenditures

Q11. Can you provide an outline of your Nuclear Generation capital expenditures discussion?

A11. My testimony will begin with the 2020 – 2023 Capital Projects Overview and then discuss and support the additional details regarding:

- Routine and Small Projects
- Non-Routine and Large Projects
- Total Nuclear Fuel
- AFUDC Forecast

2020 - 2023 Capital Projects Overview

Q12. Can you provide an overview of the Nuclear Generation capital expenditures supported by your testimony?

A12. I refer you to Exhibit A-12, Schedule B5.3, page 1 which depicts the actual capital expenditures for the historical test year ended December 31, 2020, projected capital expenditures for the bridge forecast period and projected capital expenditures for the 12-month projected test period ending October 31, 2023.

Total capital expenditures are composed of Routine and Small Projects, Non-Routine and Large Projects, and Total Nuclear Fuel. Nuclear Generation actual capital expenditures for historical test year ended December 31, 2020 totaled $271.6 million as shown on line 11, column (b) of the exhibit. Nuclear Generation forecasts total capital expenditures for the projected bridge forecast period at $450.4 million as shown on line 11, column (e) and for the 12-month projected test period ending October 31, 2023 at $120.3 million as shown on line 11, column (f).

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A portfolio of discrete projects and capital fuel expenditures provides the basis to support the forecasted Total Capital Expenditures for January 1, 2021 through October 31, 2023.

Q13. Before you discuss the discrete projects, can you summarize the principles and conduct of asset maintenance at a nuclear generation unit such as Fermi 2?

A13. Nuclear safety is our overriding priority at Fermi 2 and, indeed, throughout the nuclear industry. Our operational and strategic decisions preserve this priority.

Q14. What do you mean by nuclear safety?

A14. Nuclear safety is focused on ensuring that we maintain and operate the Fermi 2 nuclear asset with a high degree of rigor. Conservatism is necessary to minimize risk and ensure the safe and reliable use of nuclear material.

Q15. How does DTE Electric manage nuclear safety risk?

A15. DTE Electric manages nuclear safety risk through proper training, procedures and governance, operating the plant with a healthy focus on nuclear safety and maintenance of the asset.

Q16. What are the key principles the DTE Electric organization uses for maintaining the nuclear asset?

A16. I would summarize our key maintenance principles as:

1. Implementation of inspection, surveillance, maintenance and project activities are proactive and condition- or time-based to preclude a failure. Unanticipated

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equipment failures challenge plant operators; our strategies are designed to minimize the probabilities of unanticipated equipment failures.

2. Work such as capital replacements and modifications are implemented when the plant is in the safest condition to do so. For most of our work at Nuclear Generation, that safest condition is when the Fermi 2 plant is shut down for a refueling outage.

Q17. Why is it safest to perform maintenance on the Fermi 2 plant during a refueling outage?

A17. Refueling outages are the safest time to perform maintenance for the following reasons:

1. Nuclear safety - our operating license issued by the NRC requires the plant to be shut down prior to taking many systems out of service for maintenance. These licensing requirements align with minimizing risks to health and safety.
2. Personnel safety – many areas of the plant are behind locked doors during operations due to the radiological or atmospheric conditions of the area. Refueling outages offer opportunities to access these otherwise inhospitable areas of the plant for maintenance.

Q18. What is the cadence for the Fermi 2 plant refueling outages?

A18. The Fermi 2 plant currently operates on an 18-month cycle, meaning every 18 months the Fermi 2 plant shuts down for a refueling outage. The Fermi 2 refueling outages are numbered sequentially and named as such, so – our spring 2020 refueling outage, which was Fermi 2's twentieth refueling outage, was named Refueling Outage 20 or RF20 and Fermi 2's twenty-first refueling outage scheduled in the winter/spring of 2022 (approximately 18 months after RF20 concluded) is named Refueling Outage 21 or RF21.

I note here RF21 will be the last refueling outage before Fermi 2 is scheduled to begin 24-month operating cycles. Refueling Outage 22 (RF22) is scheduled for the spring of 2024; subsequent refueling outages are scheduled for the spring of the even numbered years. I will discuss the 24-month operating cycle in more detail later in my testimony.

Q19. What is the typical planning cadence for a Fermi 2 plant refueling outage?

A19. Refueling outages are highly complex and require an integrated work plan to execute thousands of activities in a relatively short duration.

Planning for a refueling outage is generally a two-year effort with many intermediate milestones guiding the planning effort. The two most relevant of these milestones for capital expenditures are (1) two years prior to the refueling outage (T+24 months), Nuclear Generation confirms the Non-Routine and Large Projects for implementation in the outage and (2) at one year prior to the refueling outage (T+12 months), Nuclear Generation establishes for the Routine and Small Projects the number of units to be completed in the outage.

Routine and Small Projects Capital Expenditures

Q20. Can you further explain the Routine and Small Projects summarized on line 2 of Exhibit A-12, Schedule B5.3, page 1?

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A20. Routine and Small Projects are those capital expenditures associated with maintaining the various assets that support the safe operation of the Fermi 2 asset and includes work such as pump, motor, valve and reactor control component replacements and can typically be expressed in number of units replaced. Routine and Small Projects are reasonable and prudent because these types of projects are the core of our proactive maintenance regime to maintain nuclear safety.

Pages 2-3 of Exhibit A-12, Schedule B5.3 provide a listing of the Routine and Small Projects that support page 1, line 2.

Q21. Can you explain the Routine and Small Projects detailed in Exhibit A-12, Schedule B5.3, pages 2-3?

A21. Exhibit A-12, Schedule B5.3, pages 2-3 shows the by-project capital expenditures for Routine and Small Projects for the historical test year and the projected expenditures for the 22-month bridge forecast period ending October 31, 2022 and the 12-month projected test period ending October 31, 2023 which total $94.8 million, $115.8 million and $37.3 million respectively.

The expenditures and project make-up are consistent for the historical test year, projected bridge forecast period and projected test period because of the regulatory and safety requirements governing Routine and Small Projects.

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Q22. Can you discuss the expenditures and rationale for the Visual Annunciator System (VAS) Replacement project shown on Exhibit A-12, Schedule B5.3, page 2, line 11?

A22. The Visual Annunciator System (VAS) capital expenditures for the historical test year, projected bridge forecast period and projected test period are $3.4 million, $9.7 million, and $0.0 million respectively. The purpose of this major plant computer system that includes computer processors, circuit cards, labeled tiles (visual displays), pushbuttons and auditory devices is to alert plant operators when a process parameter or system condition is not normal; loss of the VAS would jeopardize plant operator's ability to safely operate the Fermi 2 plant. Just like any computer, periodic replacement is necessary to address aging and obsolescence of this key digital asset. DTE Electric expects the replacement of the nearly twenty-year-old VAS to complete during RF21.

Q23. Can you discuss the expenditures and rationale for the Security video server system computer replacement project shown on Exhibit A-12, Schedule B5.3, page 3, line 50?

A23. The security video server system computer replacement capital expenditures for the historical test year, projected bridge forecast period and projected test period are $0.0 million, $12.7 million and $12.1 million respectively. The purpose of this major plant security system that includes computer servers, video cameras and other detection devices is to alert plant security of security risks and to maintain positive surveillance of the Fermi 2 Power Plant; loss of the plant's security video system would necessitate compensatory measures to ensure the physical security of the Fermi 2 site. Just like any computer, periodic replacement is necessary to

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address aging and obsolescence of this key digital asset. DTE Electric expects the replacement of the nearly twenty-year-old security system to complete in 2023.

Non-Routine and Large Projects Capital Expenditures

Q24. Can you expand your discussion for the Non-Routine and Large Projects summarized on line 3 of Exhibit A-12, Schedule B5.3, page 1?

A24. Non-Routine and Large Projects are large projects that are necessary to properly maintain the Fermi 2 asset and are incremental to normal routine capital expenditures.

Refer to Page 4 of Exhibit A-12, Schedule B5.3 for a listing of the projects that support page 1, line 3.

Q25. Can you explain the Non-Routine and Large Projects detailed in Exhibit A-12, Schedule B5.3, page 4?

A25. Yes. This exhibit shows the by-project capital expenditures for Non-Routine and Large Projects, as noted by line 3 of Exhibit A-12, Schedule B5.3, page 1. These projects for the historical test year, the projected expenditures for the 22-month bridge forecast period ending October 31, 2022 and the 12-month projected test period ending October 31, 2023 total $176.5 million, $211.7 million and $56.9 million respectively.

Q26. Referring to line 2 of Exhibit A-12, Schedule B5.3, page 4, what is a torus structure?

A26. The torus is a donut-shaped containment structure designed to absorb excess thermal energy and provide emergency water to the reactor core during a postulated accident scenario. Located beneath the reactor vessel, the torus is a very large steel pressure vessel with a major diameter of approximately 120 feet and the interior cross-section of the torus has a diameter of approximately 30 feet. During normal operations, the torus serves as a reservoir for approximately one million gallons of radioactive water. The interior of the torus structure is characterized by confined spaces, high temperatures, high humidity and high radiation.

Q27. Is the torus structure coated?

A27. A specialized torus coating protects the interior steel of the torus from corrosion. The integrity of the torus coating serves a nuclear-safety function as the coating must remain adhered to the torus shell during all design-basis operating parameters so as to not delaminate and obstruct suction points for emergency water supplies necessary to transfer water from the torus to the reactor core.

Q28. What has been DTE Electric's maintenance and inspection history for the torus containment structure coating?

A28. In 1989, during Fermi 2's first refueling outage, inspections of the torus structure coating revealed degradation regarding some submerged portions of the coating. DTE Electric reviewed the degradation and concluded at the time that the coating had adequate integrity, and that periodic inspections and repairs of the coating would be a reasonable and prudent path-forward strategy. The NRC was informed of DTE Electric's approach and did not disagree. In 1991 the NRC documented its inspection conclusions and stated that the coatings were performing satisfactorily, and minor defects are being repaired as necessary. DTE Electric routinely performed inspections and localized repairs of the coating during refueling outages to ensure the continued integrity of the coating; however, during a 2019 NRC review of the torus structure inspection reports, it determined that continuing the inspection and repair regime on the original coating would no longer be an acceptable strategy to ensure suction points for emergency water pumps would not become obstructed from delaminated coatings and that replacement of the entire submerged portions of the coating was more appropriate.

Q29. Can you explain the expenditures and rationale for the Torus Containment Structure Coating Replacement project shown on line 2 of Exhibit A-12, Schedule B5.3, page 4?

A29. Torus Containment Structure Coating Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are $100.6 million, $1.3 million and $0.0 respectively. The project's capital expenditures align to the forecasted project activities designed to complete the replacement of the submerged portions of the torus containment structure coating in RF20. To support safe operation of the Fermi 2 Power Plant and maintain committed license basis assumptions, replacement of the torus containment structure coating was reasonable and prudent.

Q30. What was the basis to replace the submerged portions of the torus containment structure coatings in RF20?

A30. DTE Electric had a nuclear safety obligation to replace the torus coating in RF20 because DTE could not demonstrate with a high level of assurance that beyond

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RF20, the submerged portions of the original torus coating – during an accident scenario – could fulfill its nuclear-safety function. The NRC agreed with DTE Electric's plan to replace the submerged portions of the torus structure coating in RF20, which created a regulatory obligation to perform the work.

Q31. What is involved in replacing the coating of the torus containment structure?

A31. As I discussed earlier, the interior of the torus structure itself is relatively inhospitable to work in and is characterized by confined spaces, high temperature, high humidity and high radiation. And recall, the torus is partially filled with about one million gallons of water, and that water is radioactively contaminated.

Although DTE Electric, during refueling outages, routinely performs inspection and remediation work in the torus structure using specialty divers, a full surface torus structure coating replacement project is a once-in-a-plant-lifetime undertaking. DTE Electric's project plan had to coordinate the safe removal of the approximately one million gallons of radioactively contaminated water from the torus structure to other onsite storage capacity which included the construction of temporary storage capacity of approximately 400,000 gallons – which is a major undertaking in and of itself. DTE Electric's project plan also had to address how to mobilize, house and coordinate access of the hundreds of incremental workers required to execute the project. DTE Electric's project plan also had to address mobilizing, staging and operating a wide array of equipment necessary to support safety, habitability, confined-space rescue, power requirements as well as the coating removal and coating application equipment. The execution of the torus

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containment structure coating replacement project was further complicated by the COVID-19 global pandemic.

Q32. Is the torus containment structure coating replacement project complete?

A32. Yes. The torus containment structure coating replacement project is complete as the coating was replaced in RF20. The torus containment structure coating was resolved to the satisfaction of DTE Electric and the NRC and will support safe and reliable operations of the Fermi 2 Power Plant through the period of extended operations ending in 2045.

Q33. Can you explain the expenditures and rationale for the Main Unit Generator projects shown on line 3 and line 20 of Exhibit A-12, Schedule B5.3, page 4?

A33. The main unit generator projects are a series of replacements necessary to address both an Original Equipment Manufacturer (OEM) design vulnerability and improve overall reliability. These projects also support electrical grid reliability. Replacement of this model of generator is the identical approach other nuclear generation owners have taken to mitigate operational risk. To support reliable operation of Fermi 2 through 2045, major refurbishments and replacement of the existing generator asset is reasonable and prudent.

The Main Unit Generator Rotor Replacement project as depicted on line 20 is to replace the existing rotor with a refurbished spare rotor. The generator rotor is forecasted to be replaced in RF21 and has capital expenditures for the historical test year, projected bridge forecast period and projected test period of $0.0 million, $18.5 million and $0.0 million respectively.

The Main Unit Generator Replacement project as depicted on line 3 is to replace the generator stator and rotor with a matched stator and rotor. This replacement is projected to occur during RF22 and has capital expenditures for the historical test year, projected bridge forecast period and projected test period of $26.6 million, $39.8 million and $31.8 million respectively.

Q34. What is the basis to replace the Fermi 2 main unit generator rotor in RF21?

A34. The Midcontinent Independent System Operator (MISO) identified that Trenton Channel Unit 9 would be designated as a System Support Resource unless an alternative solution was identified to resolve violations of applicable reliability criteria upon the unit's retirement. Replacement of the existing Fermi 2 main unit generator rotor (and the automatic voltage regulator (AVR) as shown on line 10 of Exhibit A-12, Schedule B5.3, page 4) is required in conjunction with replacement of Service System Transformer #65 and #69 (discussed later in my testimony) prior to retirement of the Trenton Channel Power Plant in May of 2022 to resolve the reliability issues that would otherwise occur. The existing Fermi 2 generator rotor and AVR are not capable of generating sufficient reactive power to solve the reliability issues identified by MISO. RF21 is the Company's last window of opportunity to replace the Fermi 2 generator rotor to maintain the Trenton Channel Unit 9 planned retirement date of May 31, 2022.

Q35. What is the basis to replace the Fermi 2 main unit generator in RF22?

A35. The existing Fermi 2 generator (stator and rotor) is the original plant equipment, manufactured in the early 1970s using the technology of that time. The equipment is approaching end of life (EOL). To date, multiple known vulnerabilities and degradation have been mitigated through increased maintenance bridging strategies; however, design vulnerabilities associated with the stator continue to represent increased risk for sudden failure. Sudden failures not only present a generation risk but also present operational risk to the plant operators responsible for maneuvering the plant to a shutdown condition following a generator failure.

DTE Electric had targeted to replace the Fermi 2 main unit generator in RF20; however, the Company determined the replacement stator was not ready for installation such that replacement of the stator could have increased operational risks to the Fermi 2 plant. The Company was reasonable and prudent in rescheduling the implementation of the generator replacement given the importance of the generator to Fermi 2's safe and reliable operation through 2045.

DTE Electric continues to work to complete the replacement stator and have the replacement stator in a ready state. RF22 is the next planned opportunity following RF21. Implementing the Main Unit Generator Replacement project in RF22 is a reasonable and prudent projection provided the current state described above. The Company has implemented and will continue to implement reasonable and prudent bridging strategies to mitigate the short-term reliability risks associated with the existing Fermi 2 main unit generator; however, understanding the importance of this generator replacement ultimately to Fermi 2's safe and reliable operation through 2045, the Company is seeking to implement the Main Unit Generator Replacement project in RF22.

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Q36. Can you discuss the expenditures and rationale for the Service System Transformer #65 and #69 Replacement project shown on line 4 of Exhibit A-12, Schedule B5.3, page 4?

A36. The Service System Transformer #65 and #69 (SST65 and SST69) capital expenditures for the historical test year, projected bridge forecast period and projected test period are $11.9 million, $16.5 million and $2.8 million respectively. The purpose of SST65 and SST69 is to supply electrical loads to plant equipment essential for safe plant operation. The SST65 is forecasted to be replaced in RF21 and SST69 is forecasted to be replaced in RF22. The transformers are being replaced to ensure power supplied remains properly conditioned once Trenton Channel Power Plant retires. The Midcontinent Independent System Operator (MISO) identified that Trenton Channel Unit 9 would be designated as a System Support Resource unless an alternative solution was identified to resolve violations of applicable reliability criteria upon the unit's retirement. Replacement of transformers was the solution identified to resolve the reliability issues and is required prior to the retirement of the Trenton Channel Power Plant in May of 2022.

Q37. Can you discuss the expenditures and rationale for the Underground Safety-Related Service Water Piping project shown on line 6 of Exhibit A-12, Schedule B5.3, page 4?

A37. The Underground Safety-Related Service Water Piping capital expenditures for the historical test year, projected bridge forecast period and projected test period are $8.0 million, $21.6 million and $2.5 million respectively. The Underground Safety-Related Service Water Piping project will replace nuclear safety-related piping that delivers cooling water to various components that support the operation of the nuclear reactor. The replacement of the underground service water piping is necessary to address normal age-related degrading pipe-wall thickness and to ensure this pipe will continue to support plant operations through the end of the operating license in 2045.

Q38. Can you discuss the expenditures and rationale for the Boraflex Fuel Storage Racks project shown on line 8 of Exhibit A-12, Schedule B5.3, page 4?

A38. The Boraflex fuel storage racks capital expenditures for the historical test year, projected bridge forecast period and projected test period are $4.0 million, $6.1 million and $2.4 million respectively. The Boraflex fuel storage racks project will replace the end-of-life Boraflex spent fuel storage racks with new neutron-absorbing material. The replacement of the Boraflex storage fuel racks is necessary to restore safety margins for the storage of the spent fuel through the end of the operating license in 2045 and to ensure compliance with Fermi 2's renewed operating license.

Q39. Can you discuss the expenditures and rationale for the torus vent header coating replacement project depicted on line 21 of Exhibit A-12, Schedule B5.3, page 4?

A39. For clarity, the torus vent header coating replacement project is a distinct project from the previously discussed torus containment structure coating replacement project. The torus vent header coating replacement capital expenditures for the historical test year, projected bridge forecast period and projected test period are $0.0 million, $40.0 million and $0 million respectively. The torus vent header is a ring header located within the torus structure and is designed to distribute

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water/steam into the torus as steam is released from safety relief valves during a postulated accident scenario; like the torus structure, the torus vent header has a specialized internal coating to protect the torus vent header pipe from corrosion. The torus vent header coating has reached the end of its useful life and requires replacement. The torus vent header coating replacement project is a reasonable and prudent project to replace the existing torus vent header coating with a qualified replacement coating to support continued safe and reliable operations of the Fermi 2 Power Plant.

Q40. Can you discuss the expenditures and rationale for the drywell cooler projects shown on lines 9, 12 and 17 of Exhibit A-12, Schedule B5.3, page 4?

A40. These drywell cooler projects are a series of drywell cooler replacements that we have grouped by refueling outage implementation. The replacement of these coolers is necessary to address the normal end of life status of these coolers which are original plant equipment. Fermi 2 has 14 drywell coolers which provide the containment structure that surrounds the reactor with atmospheric cooling during normal operations.

Drywell Coolers #10 and #14, as depicted on line 9, were replaced in RF20 in the spring of 2020 and have capital expenditures for the historical test year, projected bridge forecast period and projected test period of $2.4 million, $0.4 million and $0.0 million respectively.

Drywell Coolers #12 and #13, as depicted on line 12, are forecasted to be replaced in RF21 and have capital expenditures for the historical test year, projected bridge

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forecast period and projected test period of $1.8 million, $5.7 million and $0.0 million respectively.

Drywell Cooler #8 is depicted on line 17, is also forecasted to be replaced in RF21 and has capital expenditures for the historical test year, projected bridge forecast period and projected test period of $0.1 million, $3.8 million and $0.0 million respectively.

Q41. Do any of the projects listed in Exhibit A-12, Schedule B5.3, pages 2-4 contain contingency amounts?

A41. No. The capital expenditures as shown in Exhibit A-12, Schedule B5.3, pages 2-4 do not include contingencies.

Q42. How does Nuclear Generation organization manage its capital expenditures without contingencies?

A42. Nuclear Generation manages to total capital expenditures for the period and expects that capital expenditures in total will be incurred as projected. In general, Nuclear Generation maintains a prioritized list of projects such that as project forecasts are over or under expected amounts, Nuclear Generation uses this this prioritized list consistent with the key principles I described earlier to manage the Nuclear Generation portfolio of projects.

<u>Nuclear Fuel Capital Expenditures</u>

Q43. Can you explain Total Nuclear Fuel summarized on line 10 of Exhibit A-12, Schedule B5.3, page 1?

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A43. Yes. Total Nuclear Fuel includes those capital expenditures for the various components of the nuclear fuel cycle: (1) Uranium, (2) Conversion, (3) Enrichment and (4) Fabrication.

Uranium refers to the costs associated with mining and milling uranium. Natural uranium is obtained from the exploration and mining of uranium ore. Milling is the mechanical and chemical process of extracting uranium from the mined ore in the form of U3O8, commonly referred to as yellowcake. The U3O8 is the feed material for the conversion process.

Conversion refers to the costs associated with chemically converting U3O8 into UF6, uranium hexafluoride. The UF6 is the gaseous compound used as a feed in the enrichment process.

Enrichment refers to the costs to enrich the uranium from a natural 0.7% U235 content to a 4% to 5% U235 content required for light water reactor fuel. The enriched UF6 is used as a feed in the fabrication process.

Fabrication refers to the chemical conversion of the enriched UF6 to UO2 (uranium dioxide) powder which is then pressed and sintered into hard ceramic fuel pellets that are loaded into long, narrow zirconium alloy tubes called fuel rods; fuel rods are then assembled into fuel bundles using spacers and end fittings to hold the fuel rods together. The Fermi 2 reactor core requires 764 of these fuel bundles to operate.

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The amount of fuel purchased is determined by the design of the fuel and by the expected generation during the life of the fuel. Nuclear fuel capital expenditures were developed on the basis that Fermi 2 will transition from its current 18-month operating cycle to a 24-month operating cycle following RF21 in winter/spring of 2022.

Q44. Can you explain the Total Nuclear Fuel expenditures as shown on Exhibit A-12, Schedule B5.3, page 1, line 10?

A44. Yes. The Total Nuclear Fuel capital expenditures for the historical test year, projected bridge forecast period and projected test period are $0.3 million, $122.9 million and $26.1 million respectively and are consistent with Fermi 2's projections in the Company's 2022 PSCR Plan in Case No. U-21050.

Q45. Can you explain why Total Nuclear Fuel expenditures vary from year-to-year?

A45. Yes. Total Nuclear Fuel expenditures vary from year-to-year because Fermi 2 currently operates on an 18-month fuel cycle and fuel costs are fixed in time relative to that 18-month fuel cycle (most nuclear fuel capital expenditures occur approximately six months prior to a refueling outage); therefore, Total Nuclear Fuel capital expenditures have oscillated on a three-year pattern but as Fermi 2 transitions to a 24-month cycle at the conclusion of RF21 the Total Nuclear Fuel capital expenditures can be expected to oscillate on a two-year pattern.

Q46. How would you characterize the level of expenditures for Fermi 2's Total Nuclear Fuel?

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A46. I believe Fermi 2's fuel expenditures are reasonable and prudent. I expect fuel expenditures to continue to be reasonable as the Company has secured contracts for uranium, conversion, enrichment and fabrication through the projected test period ending October 31, 2023.

AFUDC Forecast

Q47. Can you explain the Allowance for Funds Used During Construction (AFUDC) as shown in Exhibit A-12, Schedule B5.3, page 5?

A47. Nuclear Generation capital expenditures include an Allowance for Funds Used During Construction (AFUDC) for eligible projects that are in Construction Work in Progress (CWIP); eligible projects are those projects greater than $50,000 and lasting more than six months. The actual historical period Total AFUDC – Nuclear Production Plant was $11.0 million as shown in Exhibit A-12, Schedule B5.3, page 5, line 25, column (b). The forecasted Total AFUDC – Nuclear Production Plant for the projected test period is $13.3 million as shown in Exhibit A-12, Schedule B5.3, page 5, line 25, column (c).

Q48. How did you forecast the AFUDC as shown in Exhibit A-12, Schedule B5.3, page 5?

A48. The Nuclear Production Plant – Routine Expenditures AFUDC forecast uses a historical trend to estimate AFUDC as the mix of eligible projects is fairly consistent year-to-year. The Nuclear Production Plant – Project Specific AFUDC forecast explicitly calculates AFUDC for eligible projects using project-specific CWIP balances multiplied by the AFUDC rate where the AFUDC rate is the

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authorized cost of capital rate of 5.463% consistent with the May 8, 2020 Case No. U-20561 rate order.

2020 – 2022 Capital Projects Summary

Q49. What is your opinion regarding the reasonableness of the forecasted capital expenditures for Nuclear Generation?

A49. I believe the forecasted capital expenditures for Nuclear Generation are reasonable and prudent. I believe the forecast as depicted by line 11 of Exhibit A-12, Schedule B5.3, page 1, accurately represents the capital expenditures that can reasonably be expected to continue operation of nuclear assets of similar age and vintage. My summation of projects reflects DTE Electric's commitment to ensure the safe and reliable operation of Fermi 2 through its current operating license expiration in 2045. As I have expressed previously, these capital expenditures are prudent and reasonable given the regulations, goals and conditions under which Fermi 2 operates.

Nuclear Generation O&M Expense

Q50. Can you provide an outline of your Nuclear Generation O&M discussion?

A50. Yes. My testimony will begin with the O&M Expenses Overview and then discuss and support the additional details regarding:

- Rate Case Adjustments
- Adjusted Historical Test Period
- Projected Adjustments

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<u>O&M Expenses Overview</u>

Q51. Can you provide an overview of the Nuclear Generation O&M expenses supported by your testimony?

A51. Exhibit A-13, Schedule C5.3, page 1, line 24 from left to right depicts the O&M expenses for the 12-month historical test period ended December 31, 2020, adjustments to the historical test period and then the forecasted O&M expenses for the 12-month projected test period ending October 31, 2023.

The actual O&M expenses by FERC account for the 12-month historical test period ended December 31, 2020 were $245.7 million as shown in column (c). Rate case adjustments are made in column (d) to reduce O&M by $27.8 million to account for the Nuclear Surcharge, in column (e) to reclassify Project Evaluation Review Committee (PERC) nuclear O&M project expenditures and in column (f) to reduce O&M by $25.0 million to account for 2020 COVID-19 expenditures not projected to occur within the projected test period. Note: DTE Electric expects to incur COVID-19 expenses in support of safely executing RF21; however, these expenses will occur prior to the projected test period and, as such, are not included in the test period projections. These rate case adjustments result in $192.9 million of adjusted O&M for the 2020 historical test period as shown in column (g).

Projected adjustments of $5.2 million, $5.1 million and $4.3 million in columns (h), (i) and (j) respectively account for inflation. The $14.4 million decrease in column (k) is subtracted to account for outage accrual adjustments and O&M is adjusted by $5.3 million in column (l) to account for the total PERC expense in the forecasted test period as supported by calculations performed by Company Witness Uzenski.

These projected adjustments yield a total change of $5.5 million as shown in column (m).

With the above adjustments, the forecasted O&M expenses for the 12-month projected test period are $198.4 million as shown in column (n).

Q52. What projected Total Nuclear Power Generation O&M expenses are you supporting?

A52. I am supporting projected Total Nuclear Power Generation O&M expenses of $198.4 million as shown in Exhibit A-13, Schedule C5.3, line 24, column (n) as reasonable and prudent.

Rate Case Adjustments

Q53. Can you explain the basis for the Rate Case Adjustments in column (d) of Exhibit A-13, Schedule C5.3, page 1?

A53. Site security and radiation protection costs were removed from base rates and recognized in the Nuclear Surcharge as established in DTE Electric Case No. U-14399. The Nuclear Surcharge reduction of $27.8 million as summed on line 24, column (d) accomplishes this requirement. The complete elimination of all financial statement impacts of the Nuclear Surcharge are supported by Witness Uzenski.

Q54. Can you explain the basis for the Rate Case Adjustments in column (e) of Exhibit A-13, Schedule C5.3, page 1?

A54. The Reclassify PERC adjustment nets to zero as shown on line 24, column (e). This reclassification is performed to make explicit the $11.6 million PERC Base Expense shown on line 21, column (e) and the $12.3 million of PERC Regulatory Asset amortization shown on line 22, column (e) are not inflated in the projected adjustments. I will explain the PERC Regulatory Asset mechanism later in my testimony.

Adjusted Historical Test Period

Q55. Can you explain the components that constitute the actual Total Nuclear Power Generation O&M expenses for adjusted historical test period in line 24, column (f) of Exhibit A-13, Schedule C5.3, page 1?

A55. Total Nuclear Power Generation O&M of $192.9 million consists of the Nuclear Organization, PERC Base Expense, amortization of the PERC Regulatory Asset, regulatory assessments and dues, and refueling outage expenses. I detail these expenses for the 2020 historical period on page 2 of Exhibit A-13, Schedule C5.3.

Q56. What is the need for and basis of the "Nuclear Organization" expenses that are included in the 2020 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 1?

A56. Nuclear Organization expenses are the baseline employee, services and material expenses required to safely and reliably operate Fermi 2. The Nuclear Organization expenses for the historical test period ended December 31, 2020 were $127.3 million.

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Q57. What is the need for and basis for the "PERC Base Expense" expenses that are included in the 2020 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 2?

A57. As explained and supported by Witness Uzenski, the Commission Order in Case No. U-18014 approved an annual base level of PERC expenses of $4.9 million for nuclear O&M projects and the Commission Order in Case No. U-20561 increased the approved annual base level of PERC expenses to $15.0 million; the PERC Base Expense of $11.6 million depicted on line 2 recognizes those approvals.

Q58. What is the need for and basis for the "Reg Asset Amortization - PERC" expenses that are included in the 2020 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 3?

A58. As explained and supported by Witness Uzenski, the Commission Order in Case No. U-18014 approved a regulatory asset for annual PERC projects O&M expenditures that exceed the annual base level of PERC expenses of $4.9 million for nuclear O&M projects. In Case No. U-20561, the Commission Order updated the approved regulatory asset for annual PERC projects O&M expenditures that exceed the annual base level of PERC expenses of $15.0 million for nuclear O&M projects. Order U-18014 established the amortization period of this regulatory asset as five years. Consistent with that order, the $12.3 million depicted on line 3 is the amount of the PERC Regulatory Asset amortized in 2020.

Q59. What is the need for and basis for the "Regulatory Assessments and Dues" expenses that are included in the 2020 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 4?

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A59. A majority of these assessments and dues are regulatory driven, such as those assessments and dues required by the NRC to cover oversight of the plant. In addition, assessments and dues are associated with licensing requirements including the Emergency Response Organization (ERO) and various industry groups.

Industry groups include the Institute of Nuclear Power Operations (INPO), which assists utilities in operating nuclear plants to the highest safety standards, the Nuclear Energy Institute (NEI), which assists in common issues impacting the nuclear industry, the Electric Power Research Institute (EPRI) and the General Electric Boiling Water Reactor Owners' Group, both of which sponsor research that is used by nuclear plants to operate more safely and economically.

The ERO supports the Fermi 2 Emergency Plan which is a license requirement necessary to ensure the health and safety of the public during emergency response events. The ERO funds federal, state and local county emergency facilities in support of the Fermi 2 Emergency Plan.

Q60. Which assessments and dues are non-discretionary (i.e. mandated)?

A60. NRC, INPO and ERO assessments and dues are non-discretionary.

Q61. Why does the Company pay the discretionary assessments and dues?

A61. Although not specifically mandated, voluntary participation with organizations such as EPRI and NEI are critical within a nuclear business model. In particular, organizations like EPRI that support research and development include sharing of products and services to ensure nuclear asset owners benefit as a whole from shared information. These products and services would be unaffordable without group participation and funding. The role provided by NEI is valuable to plant owners and operators in helping to shape important industry issues and regulation through a coordinated and solidified approach. The nuclear industry clearly recognizes that any one plant can abruptly upset the entire industry due to performance issues. As a result, this industry believes in significant group participation and knowledge sharing to help preclude such an event.

Q62. What is the need for and basis for "Total Refueling Outage" expenses for the 2020 historical period on Exhibit A-13, Schedule C5.3, page 2, line 10?

A62. As discussed earlier in my testimony, the Fermi 2 plant operates on an 18-month refueling cycle such that every 18 months Fermi 2 shuts down to refuel the reactor. The "Total Refueling Outage" expenses are those costs necessary to (1) refuel the Fermi 2 reactor and (2) perform offline maintenance to ensure Fermi 2 can operate safely and reliably for the next operating cycle.

The "Total Refueling Outage" expense consists of the actual refueling outage costs (line 7), the refueling outage accrual (line 8) and the refueling outage accrual reversals (line 9) for the 2020 historical period. Line 10 nets these three components and represents an accounting practice of levelizing incremental refueling expenses by accruing the anticipated refueling expenses over the term of an operating cycle.

Q63. Why does DTE Electric levelize its incremental refueling outage expenses?

A63. DTE Electric levelizes its incremental refueling outage expenses so that the difference in expense between outage and non-outage years does not burden DTE Electric customers with large rate fluctuations or create financial swings for the Company. For example, if the Company bases the rate request on the projections for a refueling outage year and all the expenses of that outage appear in that year's projections, then the Company would be presenting an unnecessarily high cost of providing Fermi 2 generation over the period the rates are in effect. The inverse is also true if the Company used a non-refueling outage year projection for the same purpose. This is consistent with the treatment in prior cases where the Commission has allowed levelized refueling outage expenses in setting rates.

Q64. What is the basis for the "Refuel Outage" expense at $51.8 million for the 2020 historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 7?

A64. This is the actual refuel outage expenditures incurred in the 2020 historical period for RF20.

Q65. How does DTE Electric manage incremental refueling outage expenses?

A65. The Company manages incremental expenses through structured planning and preparation that is consistent with industry standards and processes. We implemented rigorous financial controls that supported daily management of resources during the execution phase of the refueling outage. This management of resources includes daily reviews of scope completion, schedule and budget. As work completes, contracted resources exit promptly from the site to ensure that costs are controlled.

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Q66. What is the basis for the "Refuel Outage Accrual" expenses at $39.3 million for the 2020 historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 8?

A66. This is the actual amount accrued in the historical period for RF20 and RF21 and were consistent with projected RF20 and RF21 expenditures.

Q67. What is the basis for the "Refuel Outage Reversal" of $62.2 million for the 2020 historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 9?

A67. This is the actual amount of outage accrual that had been accrued in advance for RF20 and credited to O&M in the historical test period to offset the $51.8 million of actual RF20 refuel outage expenditures shown on line 7 and discussed above.

Projected Adjustments

Q68. Can you explain the basis for the inflation adjustments in columns (g), (h) and (i) on line 24 of Exhibit A-13, Schedule C5.3, page 1?

A68. The labor and material prorated inflation adjustment rates of 3.1% for 2021, 2.9% for 2022 and 2.9% for 2023 are supported by the testimony of Witness Uzenski. Nuclear Generation applied these forecasted inflation rates to the adjusted historical test period costs in column (g).

Q69. Can you explain the basis for the Outage Accrual adjustment in column (k) on line 24 of Exhibit A-13, Schedule C5.3, page 1?

A69. The Outage Accrual adjustment is to normalize the outage accrual for the projected test period to approximately $17 million. This Outage Accrual adjustment reflects our commitment to improving refueling outage performance and holding refueling outage expenditures relatively flat through the projected test period.

Q70. What duration have you projected for future refueling outages?

A70. The 2022 PSCR Plan (Case No. U-21050) projected an outage duration of 45 days for RF21 (projected in winter/spring 2022) and for RF22 (project for spring 2024).

Q71. Can you explain the basis for the PERC Amortization adjustment in column (l) on line 24 of Exhibit A-13, Schedule C5.3, page 1?

A71. As explained and supported by Witness Uzenski, the Commission Order in Case No. U-18014 not only approved an annual base level of PERC expenses for nuclear O&M projects, but also provided deferral and amortization treatment for any expenses over or under the base amount. The PERC Base expense was changed by $10.1 million from $4.9 million per year to $15.0 million per year in the May 8, 2020 Commission Order in Case No. U-20561.

The PERC Amortization adjustment of $5.3 million in column (1) on line 24 consists of the approved change of $3.4 million in PERC Base Expense as shown in column (l) on line 21 and a forecasted change of $1.9 million in the amortization of the PERC Regulatory Asset as shown in column (l) on line 22.

The Total PERC Expense for the projected test period is forecasted at $29.2 million as shown in column (n) on line 23. The derivation of this Total PERC Expense is shown on Exhibit A-13, Schedule C5.17 and is sponsored by Witness Uzenski; I

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detail the projects comprising line 2 of Exhibit A-13, Schedule C5.17 in Exhibit A-13, Schedule C5.16, page 1.

Q72. Can you explain the Total PERC O&M Expenditures detailed in Exhibit A-13, Schedule C5.16, page 1?

A72. This exhibit shows the by-project PERC O&M expenditures for the 2020 historical period and projected Calendar Years 2021, 2022 and 2023 planned expenditures totaling $31.3 million, $15.0 million, $24.7 million and $17.0 million respectively.

Q73. How do the Total PERC O&M Expenditures on line 26 of Exhibit A-13, Schedule C5.16, page 1 relate to Exhibit A-13, Schedule C5.17?

A73. As an example, the actual total PERC O&M expenditures of approximately $31.3 million for Calendar Year 2020 shown in Exhibit A-13, Schedule C5.16, page 1, line 23, column (b) flows to Exhibit A-13, Schedule C5.17, page 1, line 2, column (c).

Q74. How does the PERC amortization expense on line 13 of Exhibit A-13, Schedule C5.17, page 1 relate to Exhibit A-13, Schedule C5.3, page 1?

A74. Exhibit A-13, Schedule C5.17 shows the calculation for PERC amortization that was derived from Exhibit A-13, Schedule C5.16, Page 1. Exhibit A-13, Schedule C5.17, page 1, line 13, column (g) shows $14.2 million as the calculated amortized portion of PERC O&M for the 12-month test period ending October 31, 2023. This $14.2 million is used in Exhibit A-13, Schedule C5.3, page 1, line 22, column (n).

Q75. What is the rationale for the 24-Month Operating Cycle project shown on line 5 of A-13, Schedule C5.16, page 1?

A75. The 24-month operating cycle project is intended to reduce the frequency of Fermi 2 refueling outages and improve operating time. Operating on a 24-month cycle results in three refueling outages every six years; operating on an 18-month operating cycle results in four refueling outages every six years. As discussed earlier, Fermi 2 currently operates with 18-month operating cycles; therefore, transitioning to a 24-month operating cycle will result in additional generation over a six-year cycle due to fewer refueling outages.

Fermi 2's cycle length is limited by our NRC license. The 24-Month Operating Cycle project performs analysis to ensure the plant is capable of operating 24 months between refueling outages and submits that analysis as a license amendment request to the NRC to update the Fermi 2 license to allow a 24-month cycle. DTE Electric received NRC approval in early 2021 which means Refueling Outage 21 (RF21) in the winter/spring of 2022 will be the last refueling outage following an 18-month cycle.

The Company first introduced the 24-Month Operating Cycle project in Case No. U-20162. The Commission responded favorably and approved cost recovery associated with the 24-Month Operating Cycle project in the Order U-20162, dated May 2, 2019.

Q76. What are the expenditures and the rationale for the Main Unit Generator Inspection project shown on line 1 of A-13, Schedule C5.16, page 1?

A76. The Main Unit Generator inspection project as depicted on line 1 is part of the Company's bridging strategy to ensure the Main Unit Generator is capable of safe and reliable operations. DTE Electric completed a generator inspection in RF20 with actual expenditures in Calendar Year 2020 of $8.4 million and will conduct another generator inspection during RF21 with projected expenditures in Calendar Year 2022 of $7.7 million as shown on line 1 of Exhibit A-13, Schedule C5.16, page 1.

Q77. What are the expenditures and the rationale for the Fermi 2 Nuclear Decommissioning Study project shown on line 9 of A-13, Schedule C5.16, page 1?

A77. The Fermi 2 Nuclear Decommissioning Study project represented the effort required by the Company to accomplish the Commission's directive in Case No. U-20162, requiring DTE Electric to complete an updated decommissioning study.

The Company initiated the project to update the Fermi 2 nuclear decommissioning study soon after issuance of the May 2, 2019 Order in Case No. U-20162. As discussed in previous rate filings, this nuclear decommissioning study was complex, required allocation of Company resources and took approximately a year to complete. On January 29, 2021, DTE Electric submitted this study's updated conclusions within the DTE Electric Company's Report on the Adequacy of the Existing Annual Provision of Nuclear Plant Decommissioning (also referred to as the Fermi 2 triennial decommissioning report). The Fermi 2 Nuclear Decommissioning Study project had actual expenditures in Calendar Year 2020 of $0.7 million as shown on line 9 of Exhibit A-13, Schedule C5.16, page 1.

I consider the Fermi 2 Nuclear Decommissioning Study scope reasonable and prudent to accomplish the task the Commission concluded should be conducted.

Q78. What were the conclusions of the Fermi 2 Decommissioning Study project?

A78. The Fermi 2 decommissioning study provides two primary conclusions: (1) the site-specific decommissioning cost estimate reinforced that DTE Electric's existing practice of annual review and update of the Fermi 2 nuclear decommissioning cost estimates is reasonable and prudent and (2) the existing annual Nuclear Surcharge funding provision for nuclear decommissioning is presently appropriate, reasonable and prudent.

Q79. Is the Company requesting a change to the annual amount of the Nuclear Decommissioning Funding portion of the Nuclear Surcharge as an outcome of the Fermi 2 Decommissioning Study project?

A79. No. The annual amount of the Nuclear Decommissioning Funding portion of the Nuclear Surcharge was extensively reviewed in the MPSC Case No. U-20162 proceeding and subsequent reviews demonstrate it is reasonable and prudent to maintain the Nuclear Decommissioning Funding portion of the surcharge unchanged. The Fermi 2 Decommissioning Study further supports the Commission's findings from U-20162 that the annual Nuclear Decommissioning Funding portion of the Nuclear Surcharge of approximately $2.9 million is presently reasonable and prudent.

Line No.

Q80. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended Power Uprate (EPU) Study project shown on line 21 of A-13, Schedule C5.16, page 1?

A80. The Fermi 2 Extended Power Uprate (EPU) Study project is to provide a detailed feasibility, scoping and estimating analysis, regarding the potential for Fermi 2 to support an EPU. The Fermi 2 EPU Study project actual expenditures in Calendar Year 2020 and forecasted Calendar Years 2021, 2022 and 2023 are $0.0 million, $0.0 million, $0.0 million and $4.9 million respectively as shown on line 21 of Exhibit A-13, Schedule C5.16, page 1.

Q81. What is an EPU?

A81. U.S. Commercial reactors, such as Fermi 2, were designed with excess capacity that would allow for a potential uprate; however, the NRC licenses for commercial nuclear power plants establishes limits on the maximum heat output, or power level, for the reactor core; this power level plays an important role in many of the analyses that demonstrate plant safety, so the NRC's permission is required before a plant can change its maximum power level. The NRC has approved EPU increases as high as 20 percent; however, EPUs usually require significant modifications to major pieces of non-nuclear equipment such as turbines, main generators, pumps and motors, transformers and steam dryers.

Q82. What would be the potential benefit of performing an EPU at the Fermi 2 Power Plant?

A82. Performing an EPU at the Fermi 2 Power Plant could yield an additional 172 MWe of carbon-free, baseload generation capacity for Michigan.

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Q83. What would be the potential benefit of performing the Fermi 2 EPU study?

A83. An EPU project would be complex with considerable scope and cost unknowns; for example, DTE Electric's level of efforts analysis provides a total EPU cost ranging between $600 million and $1,000 million with the largest drivers of cost uncertainty being unknowns regarding the margins available within Fermi 2's existing equipment such as the steam dryer, emergency equipment cooling system strainers, turbine valves, main steam lines and main unit generator to operate safely at EPU conditions or if the existing equipment must be replaced to support EPU conditions. Performing the EPU study would allow DTE Electric to narrow the uncertainty in scope and cost to support a reasonable and prudent decision for a Fermi 2 EPU.

Q84. What would be the deliverable of the Fermi 2 EPU Study?

A84. The Fermi 2 EPU study would perform a detailed analysis of Fermi 2's existing equipment and determine the required actions to support Fermi 2 EPU operations; analysis would recommend if existing equipment can support EPU through additional engineering analysis or if existing equipment must be replaced. The analysis will support cost estimates for the individual EPU sub-projects as we evaluate the total EPU costs. DTE Electric expects the study to take several years to complete, as equipment such as the steam dryer requires a refueling outage to access and instrument for margin analysis. Once the study concludes in 2025, we will have a more certain understanding of the scope and costs required to perform an EPU at Fermi 2 Power Plant.

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Q85. What are the Total Nuclear Power Generation O&M expenses that you support for the projected test period ending October 31, 2023?

A85. I support Total Nuclear Power Generation O&M expenses of $198.4 million for the projected test period as shown in Exhibit A-13, Schedule C5.3, page 1, line 24, column (n). As I have discussed previously, these projected Total Operation and Maintenance expenses are required for the safe and reliable operation of Fermi 2 for the projected test period. I consider these expenses to be prudent and reasonable.

Nuclear Surcharge

Q86. Is the Company requesting a change to the Nuclear Surcharge?

A86. Only with respect to inflation for the Site Security and Radiation Protection portion of the Nuclear Surcharge. The Company is proposing an updated Nuclear Surcharge based on the same approach approved by the Commission in Case Nos. U-17767, U-18014, U-18255, U-20162 and U-20561 and depicted in Exhibit A-20, Schedule J1.

The Site Security and Radiation Protection portion of the surcharge has been updated to reflect 2020 historical expense plus inflation on line 2. The inflation rate is supported by Witness Uzenski on Exhibit A-13, Schedule C5.15.

The Nuclear Decommissioning Funding portion of the surcharge shown on line 3 is unchanged.

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The Low Level Radioactive Waste (LLRW) Disposal Funding portion of the annual surcharge shown on line 4 is unchanged.

The resulting nuclear surcharge set forth in Company rates is supported by Company Witness Willis on Exhibit A-16, Schedule F6.

Q87. What is the Nuclear Surcharge that you support for the 12-month projected test period ending October 31, 2023?

A87. I support the Proposed Nuclear Surcharge of $39.1 million for the projected test period as shown in Exhibit A-20, Schedule J1, page 1, line 5, column (b); this represents an increase of approximately $0.3 million from the current authorized Nuclear Surcharge shown on line 6, column (b). The Proposed Nuclear Surcharge funds Fermi 2 site security, radiation protection, nuclear decommissioning and the disposal of LLRW; these activities are required for safe and secure operation of the Fermi 2 Power Plant for the projected test period. I consider the Proposed Nuclear Surcharge to be prudent and reasonable.

Q88. Does this complete your direct testimony?

A88. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MORGAN ELLIOTT ANDAHAZY

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MORGAN ELLIOTT ANDAHAZY

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Morgan Elliott Andahazy (she/her/hers). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your education background?

A3. I hold a Bachelor of Science in Engineering (Industrial and Operations Engineering), and a Master of Business Administration, both from The University of Michigan, Ann Arbor.

Q4. What work experience do you have?

A4. In 2007, I joined DTE Electric as a Contract employee supporting the Distribution Operations Continuous Improvement (DOCI) team. In March 2008, I joined DTE Electric as a full-time employee and a Project Lead within the DOCI team. As a Project Lead, I was responsible for measuring and improving productivity within the Electric Field Operations (EFO) organization. During this time, I obtained my Six Sigma Black Belt based on work I did with EFO Productivity projects. In 2009, I transitioned to the Continuous Improvement (CI) Manager for Distribution Operations (DO) where I was responsible for the team of Project Leads supporting improvement projects throughout DO. In March 2010, I was moved to a new developmental assignment as a Field Supervisor for the Underground (UG) Cable

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Pulling team at the Trombly Service Center. At Trombly I was responsible for overseeing the daily construction work performed by the UG Cable Pullers, and supervising a Union represented workforce. In January 2011, I was promoted to the CI Manager for Corporate Services. I was responsible for coordination and implementation of CI training to the organization, and I led the team of CI experts responsible for improvement projects. In October 2011, I transitioned to Manager, Trombly Service Center, where I was responsible for all UG operations (cable pulling and cable splicing) for the Southeast (SE) Region of DO. In April 2013, my role expanded to Manager, SE Region, which consisted of three service centers (Trombly, Redford, and Caniff) and included all Overhead (OH) and UG operations in the SE Region. In March 2016, I was promoted to Director, Service Operations responsible for all OH and UG operations in Southwest (SW), Northwest (NW), and Northeast (NE) regions in DO. In this role, I also assisted in Local 17 contract negotiations. In October 2017, I assumed my present position as Director, of the Advanced Distribution Management System project.

Q5. What are your current duties and responsibilities with DTE Electric?

A5. I lead the team responsible for the successful implementation of the new Advanced Distribution Management System (ADMS). This team is responsible for the strategic direction, vendor selection, and implementation of all ADMS components including the Generation Management System (GMS), Energy Management System (EMS), Outage Management System (OMS), Distribution Management System (DMS), and the Network Management System (NMS).

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Q6. Have you sponsored testimony in a case before the MPSC before?

A6. No.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to describe the Company's progress in implementing the Advanced Distribution Management System (ADMS) to improve DTE Electric's ability to monitor and control its distribution grid as referenced in Company Witness Pfeuffer's Exhibit A-23, Schedule M1, 2021 Distribution Grid Plan, MPSC Case No. U-20147 (DGP). I also describe the Company's progress on design and construction of the new Electric System Operations Center (ESOC) and the Alternate System Operations Center (ASOC) as referenced in Witness Pfeuffer's Exhibit A-23, Schedule M1, 2021 Distribution Grid Plan, MPSC Case No. U-20147 (DGP). In addition, my testimony also addresses the required capital expenditures and continued justification to complete these implementations.

Advanced Distribution Management System (ADMS)

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-12	B5.4	Projected Capital Expenditures – Distribution Plant (page 11, lines 2 through 5)
A-23	M6	Distribution Plant Capital Project Detail – Technology and Automation (ADMS and ESOC/ASOC projects)

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Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

Q10. Can you describe the scope of the ADMS program?

A10. As described in Company Witness Bruzzano's testimony in MPSC Case No. U-20561 (4T 186-196), the ADMS program is the umbrella name for three tightly connected projects that consist of five components with distinct yet complimentary objectives. The three projects included are:

- Generation Management System (GMS) and Energy Management System (EMS)
- Outage Management System (OMS) and Distribution Management System (DMS)
- Network Management System (NMS)

The ADMS program is comprised of the hardware and its associated software 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 "advanced" portion of the ADMS refers not just to improved functionality, but also to the significant level of integration that is now available across components that in the past were separate, in terms of communication, from one another. These components, and the business processes that enable them, perform different functions but benefit significantly from being able to share data seamlessly.

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Q11. Can you describe the five components included in the ADMS program?

A11. The ADMS is comprised of five functional components:

- Generation Management System (GMS): allows the Company to manage the Generation fleet and includes Automatic Generation Control (AGC) to balance the system load and support frequency control; utilized to interface with the Midcontinent Independent System Operator (MISO).
- Energy Management System (EMS): allows the Company to model the subtransmission system and the connections to the transmission system; provides tools to analyze real-time system conditions including State Estimation and Contingency Analysis which are the tools that analyze the system and provide data demonstrating current performance, and performance in defined contingency situations, so operators can make informed decisions to maintain system reliability; and allows the Company to operate devices on the subtransmission system via Supervisory Control and Data Acquisition (SCADA).
- Outage Management System (OMS): aggregates emergent trouble information reported by customers and Advanced Metering Infrastructure (AMI) meters and allows system operators and dispatchers to prioritize response and properly assign crews for repairs. Emergent trouble is defined as storm and non-storm, outage and non-outage events reported in the system.
- Distribution Management System (DMS): provides a complete network model of the electrical system for operators to view system conditions in real time. DMS consists of multiple applications such as Network Model (eMap), Distribution Power Flow (DPF), Distribution State Estimation

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(DSE), and applications with more advanced functionality such as Fault Location, Isolation, and Service Restoration (FLISR), Volt/Var Control (VVC), Conservation Voltage Reduction (CVR), Feeder Reconfiguration (FR) and electronic Switch Order Management (SOM). DMS allows the Company to gain and access advanced situational awareness of the distribution system from the Transmission Interconnection to the customer's connection on the distribution system**.**

- Network Management System (NMS): allows the Company to maintain high quality system data, which is essential to the safe and effective monitoring and operations of the grid.

Q12. Were the ADMS project costs included and approved for recovery in DTE Electric's previous rate case?

A12. Yes. The ADMS project was discussed in depth in Witness Bruzzano's testimony in both MPSC Case No. U-20162 and MPSC Case No. U-20561. In its May 2, 2019 order in MPSC Case No. U-20162, the Commission stated the following on page 29 when referring to ADMS: "The Commission finds this capital expense amount to be reasonable in light of the significant improvements in reliability, integration with distributed resources, and substation outage risk that are offered by ADMS, and the fact that it is becoming commonplace in the industry." The projected expenditures presented in MPSC Case No. U-20561, Exhibit A-12, Schedule B5.4, for the ADMS DMS/OMS project totaled $64.7 million. Based on the defined test year, the amount included in the rate base was $58.1 million.

Q13. How will customers benefit from the ADMS implementation?

A13. Customers will benefit from reduced outage durations and from better communication on the status of their electric service and expected restoration times. Table 1 identifies the operational improvements that are expected to occur, including related improvements in All-Weather SAIDI, due to ADMS implementation. The third column in Table 1 denotes the expected improvement in the All-Weather SAIDI.

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Table 1 Estimated All-Weather SAIDI Improvements from ADMS

Benefit Driver	Description of Benefits	Estimated All-Weather SAIDI Benefit
As-operated electrical Model Analysis	Utilize to view and analyze the as-operated electrical model to make informed decisions about how to restore customers	4-8 minutes
Trouble Call Analysis	Utilize remote monitoring capabilities to confirm trouble locations when devices in the field have opened and transmitted their status	4-8 minutes
Assign the Appropriate Crew	Utilize the as-operated model to determine the appropriate resources (e.g., OH vs. UG) to respond to an outage	1 minute
Nested Outage Notification	Utilize the as-operated model to identify incidents of nested outages (trouble behind trouble) to better direct restoration crew efforts	1 minute
Closest Crew Assignment	Utilize the as-operated model integrated with vehicle GPS to locate the closest available crew to an outage	2-3 minutes
Fault Location Identification	Provide a visual indication of the possible fault locations, allowing SOC to better develop a restoration strategy and the field crew to more quickly locate the troubled section of the circuit	5-10 minutes
Momentary Interruption Analytics	Utilize Momentary Interruption Analytics to produce daily reports of the number and location of momentary faults; patrol and resolve before momentary outages become sustained outages	0-1 minute
Switch Order Management System	Utilize the Switch Order Management System to quickly determine switching solutions for restore-before-repair	1-3 minutes
Restoration Switching Analysis	Utilize Restoration Switching Analysis to develop multi-step plans for optimal switching to restore customers based on current system conditions	4-14 minutes
Simulation Tools for Outage Restoration	Utilize Simulation tools to conduct contingency studies to simulate the impact of a restoration plan on the broader electrical system	2-3 minutes
Storm Damage Assessment	Utilize ADMS to assess initial storm damage to better direct resources for restoration efforts	3-4 minutes
Improve SCADA Availability	Monitor the health and availability of SCADA devices to minimize down time and maximize control and monitoring capability	2-4 minutes
Total		***29 - 60 minutes***

Q14. Are additional benefits expected to be realized due to the implementation of ADMS?

A14. Yes. There are a number of the additional benefits that were originally detailed in Witness Bruzzano's testimony in MPSC Case No. U-20561, and were also discussed in detail in the Distribution Grid Plan (DGP) section 12.1. First, the existing technology the Company had/has in operation was reaching end-of-life and needed to be replaced regardless of implementing a full ADMS (includes GMS, EMS, and OMS). Second, implementing a common platform for the GMS, EMS, OMS, and DMS allows the components to seamlessly share data from across the electrical system grid to provide real-time visibility of current conditions and provide operational control of the distribution circuits. Third, the DMS applications will allow the Company to improve many of the current manual processes in place to monitor and operate the electrical grid, such as the paper SOM process. Fourth, improved data quality allows employees to have a better understanding of the current system configuration in the field, allowing for improved communications between the control room and field employees; this improved communication will also materially improve safety by allowing the field employees visibility into the current configuration of the equipment while in the field so they can see a visual representation of the information being discussed with the control room and collaborate to create the safest restoration plan. Fifth, the ADMS allows the Company to fully leverage investments made in the field while modernizing the electrical grid, improving the ability to integrate Distributed Energy Resources (DER) and providing a centralized tool for managing VVC and CVR. Please refer to section 12.1 of the Distribution Grid Plan for more details of benefits of ADMS platform in different scenarios.

Q15. What was the original implementation strategy for ADMS at DTE Electric?

A15. The Company began the journey to invest in an ADMS in 2015 and 2016 by meeting with utilities with good reliability performance and found that these utilities had invested in deploying superior technology for monitoring grid condition and operating devices remotely, which can be broadly defined as Advanced Distribution Management Systems. The Company spent most of 2017 developing the ADMS implementation strategy and defining the scope of the project, including the functionality and associated specifications needed to upgrade and integrate the Company's legacy systems. This strategy also included establishing the proper project management process and oversight, utilizing the Company's internal project management experts, the Major Enterprise Project (MEP) organization, and their extensive experience with multi-year technology investment programs. The oversight of the ADMS projects included frequent Executive Steering Committee meetings with MEP, IT and Operations Senior Executives, monthly touchpoints with the Vendor's executives, and weekly team reviews with the vendor to ensure progress was on track, and risks were identified and escalated quickly.

Q16. What was the original planned sequence for the ADMS implementation?

A16. The Company developed the optimal sequence for implementing the three ADMS projects based on the status of the current systems. The GMS/EMS project was scheduled first as the legacy systems had already reached end-of-life, and the EMS is the foundation for all other ADMS components. The second project planned was the NMS so the Company could improve the overall data quality in its source records so the new systems would run more effectively. The third project to be implemented would be the OMS/DMS and would be rolled out in multiple phases.

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The Company's strategy was to implement the DMS Network Model application, along with the OMS in the first phase. The new OMS would also require a new mobile component to be installed to allow field resources to receive assigned trouble work, and associated details of the jobs. The remaining DMS applications would be rolled out in the final two phases of the OMS/DMS project. Not only did this sequence allow the Company to replace the components in the order best suited to relieve aging systems first, it also allowed the ADMS vendor additional time to continue to mature their newer ADMS components, in particular the mobile component of the OMS.

Q17. What vendors were selected by DTE Electric for the ADMS suite of products?

A17. In 2017, DTE Electric hired Accenture to assist the Company in scoping the ADMS project and in recommending the best ADMS vendor. Through a rigorous selection process, the Company determined that OSI Inc. (OSI) was the best partner for the GMS, EMS, OMS, and DMS. In 2018, DTE Electric conducted another selection process for the NMS project. The Company selected Cyient as the NMS vendor due to their expertise in data quality management.

Q18. Why did DTE Electric select OSI as their main ADMS vendor?

A18. OSI offered a fully integrated platform across the four ADMS components (GMS, EMS, OMS, and DMS). OSI was clearly an industry leader in the GMS and EMS space, at the time serving 84 large utility customers in North America and receiving outstanding customer feedback. Most importantly for the Company, OSI had robust North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) and security capabilities, which are critical in light of rising cybersecurity threats. The Company recognized that OSI's OMS product was still relatively new and that their mobile solution supporting the OMS (Compass) was still in the development phase. However, none of the competitors had a full suite of mature products to meet the Company's needs either, and OSI's strong reputation coupled with their user-friendly interfaces, development roadmap, and security benefits ultimately led to their selection.

Q19. Can you describe the original schedule for implementing ADMS?

A19. The GMS was scheduled to be in operation by the end of 2018, followed by the EMS in 2019 and the NMS in 2020. In addition, the first version of the OMS software was scheduled to be delivered in June 2019. This delivery would have supported an implementation in late 2020. The DMS phase of the project was scheduled to kick off in July 2019, which supported a staggered implementation throughout 2021, transitioning into full day to day operational support in 2022.

Q20. Have any ADMS components been successfully implemented?

A20. Yes. The Company successfully completed the implementation of the GMS in 2018, followed by the EMS in 2019, and NMS in 2020.

Q21. You indicated that the NMS was successfully implemented in 2020. There is additional funding requested included in this instant case, Exhibit A-12, Schedule B5.4, related to NMS. Please explain.

A21. The initial NMS project set the foundation for the Company to maintain high quality system data, which is essential to the safe and effective monitoring and operation of the electrical grid. This source data is imported into the DMS Network

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Model application and is the basis for the outputs of all other ADMS applications. It is imperative to have high quality data in the Network Model to ensure safe, reliable, and accurate interpretation of the current status of the system when utilizing the ADMS in daily operations. This additional investment, totaling $6.3 million in years 2021-2023, will support further development of high-quality data in the Network Model that was not included in the original scope of the NMS project.

Q22. What additional data quality functionality is included in this funding and why is it necessary?

A22. The foundation for the evolving Distribution Planning processes is a high-quality Network Model including grid topology and electrical characteristics. As part of the recent grid modernization strategy efforts, the Company determined additional investments were needed in the Network Model data quality to support the advanced planning tools and process for scenario planning. This is a new request for additional work on the Network Model that was identified as being beneficial when the initial work was completed and can be considered phase two of the NMS project. These additional Network Model investments include technology to better align field conditions and maps to the digital representation of the grid, integration 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. If we do not make these additional investments, the Company will require additional O&M personnel to manually maintain data between systems, which will introduce more opportunity for

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incorrect data entry and discrepancies between asset systems. The value of the components of the ADMS depends directly on the accuracy of this data.

Q23. What additional funding is required through 2023 to add the enhancement you just described?

A23. Given its foundational role, the Network Model requires enhancements to support the full ADMS deployment as the complexity of the grid increases. In 2021-2023, DTE Electric will invest $6.3 million to configure and develop common platform maps for subtransmission operating maps, substation one-line diagrams, and primary service customer diagrams to enable dynamic generation of these maps and diagrams from the Geographic Information System (GIS) mapping system. Additionally, this funding amount covers the cost for the Company to implement four asset integration configurations between the asset management and GIS systems during 2022 and an additional three such configurations during 2023. These asset integration configurations are necessary to automatically maintain consistency between our enterprise asset systems for technical data required for planning studies, such as automatically creating an asset record with kVA size in our asset management system for a regulator when it is created in our GIS connected model. These additional investments are required to support and realize the full customer benefits of the ADMS as detailed in Table 1 and to support timely studies of customer requests to connect to the grid through the distribution planning processes.

Q24. In light of the planned enhancements, what additional data will be available?

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A24. Additional data needed range from schematics to support switching and tagging in the short term, to engineering and control setting information to support advanced functionality, such as smart inverters functionality in ADMS in the long term. This increased detail in network model fidelity will require Network Model enhancements to support consolidation (defined as the creation of additional details into the Network Model through ESRI software that do not exist in the systems today) of one set of asset attributes across operating maps each in 2022 and 2023.

To increase efficiency and accuracy of maintaining the growing volume of data in grid models for planning and operations, DTE Electric needs technology solutions to continuously improve data integrity to efficiently maintain data input. We will implement four analytical models each in 2022 and 2023 to continuously improve targeted areas of our network model. These analytical models provide this critical data integrity function by performing anomaly detection and correction to fill in missing data or correct data elements in source systems through an automated technology solution. The cost for building and implementing these network models in 2022 and 2023 is included in the funding amount. Additional details can be found in section "12.9.4.3 Network Model" of the DTE Electric 2021 Distribution Grid Plan, Exhibit A-23, Schedule M1 sponsored by Witness Pfeuffer. As described in the Distribution Grid Plan (DGP), in Exhibit 12.9.4.3.1 Network Model Capital Investment, page 427, the Company expects continued investment in the data quality supporting the Network Model outside of this rate case timeframe to continue to support the increased need for additional aspects of high-quality data to leverage technological investments in the future.

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Q25. Can you describe the customer benefits to these additional investments in the Network Model?

A25. Customers will benefit from these additional investments in the Network Model through downstream planning and operational processes that leverage the as-built network model. The network model will enable DTE Electric to respond in a timelier fashion to requests for connecting customers' distributed generation and distributed storage through the Company's planning processes. The network model also supports DTE Electric's ability to plan and adapt to the changing needs of the grid, such as planning for system upgrades driven by greater electrification as described in the Grid Modernization plan, which in turn supports our customers' interests in modernizing their factories, businesses, and homes with cleaner and more efficient technology like EVs, solar panels, and batteries.

Q26. Can you describe the progress to date for the OMS and DMS components of the project?

A26. Under the original schedule with phased implementation of the different ADMS components, the Company planned to implement the OMS in late 2020, and to stagger the multiple DMS applications between late 2020 and the end of 2021. For several reasons that I will explain in more detail below, OMS and DMS implementation has been delayed. Due to the staggered deployment strategy, the Company is in different stages of implementation for the remaining OMS and DMS components. Most of the OMS and DMS are now scheduled for completion by the end of 2022, as discussed later in my testimony. In early 2020, DTE Electric hired an experienced System Integrator (Ernst & Young) to support the OMS/DMS project, which is industry standard practice when implementing an ADMS. The

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System Integrator helps the company with the overall delivery strategy, coordinates all testing efforts, coordinates integration between software packages (new and legacy software), and creates appropriate training materials for the organization. For the OMS and the DMS Network Model application, the team has completed system configuration, Factory Acceptance Testing (FAT), and Site Acceptance Testing (SAT). In addition, the Company has developed drafts of the associated training materials and conducted "Train the Trainer" sessions for the OMS. The project team is currently working through System Integration Testing (SIT), defect remediation and testing, and partnering with OSI on enhanced functionality (enhancements) to improve the base product and meet additional operational needs. This due diligence and system refinement before full deployment are absolutely necessary to ensure a successful roll out given the critical role of these systems to overall system reliability and safety. The training materials and training sessions will also be completed as defects and enhancements are remediated by OSI to support the rollout and implementation with accurate, easy-to-understand tools for all users. For the remaining DMS applications, the Company is in the process of system configuration and preparing for the upcoming testing cycles (FAT, SAT, and SIT).

Q27. What caused the delays for the OMS and DMS components?

A27. The major cause of the delay in the OMS and DMS components was the development and delivery of the mobile Compass tool from OSI (I will discuss the criticality of the mobile tool to the OMS implementation later in my testimony). While there was some delay early in the project to ensure Compass was compatible with multiple field devices (iOS, Android, etc.), most of the delay occurred in 2020 and 2021. Specifically, OSI delivered the first working Compass test environment in the second quarter of 2020, opposed to December 2019 as planned. Once the base product was delivered, the Company partnered with OSI to continue developing the additional functionality required to replace the Company's existing (legacy) mobile tool and to improve the functionality between the new Compass mobile tool and the base OMS product. Restrictions imposed during the COVID pandemic made the partnership and continued development of the Compass tool extremely challenging. For example, the OSI and DTE Electric project teams were not able to travel and meet in person until August 2021. Due to the complexity of the technology required to support the needed mobile functionality, and the increased complexity of partnering on a project of this magnitude given the restrictions in place due to the pandemic, the Company had to make the decision to move the implementation date of the DMS Network Model, OMS, and Compass mobile tool. The critical nature of these systems to the Company's daily operations informed this decision. Although some systems can be deployed and continued to be refined over time after they are live, it was determined that this system needed additional design improvements and testing in order to be ready for use in operations by the Company and avoid potentially costly workarounds and problems. As discussed in more detail later in my testimony, the new implementation date is the fourth quarter of 2022 to accommodate the time needed for OSI to remediate the issues and develop required enhancements. This timing has the additional benefit of ensuring the cutover of systems does not occur during the summer when our customers experience higher outage related issues and these tools are critical to our ability to restore customers. In this context, cutover is defined as the point when the new component is turned on/implemented and the old component (in the case of a replacement system) is turned off. Due to original sequencing of the OMS/DMS project, where DMS implementation follows OMS implementation, the delay in implementing OMS caused the remaining phased DMS implementation schedule to shift into 2022 as well.

Q28. Why is the mobile component of the ADMS critical to cutover to the new OMS?

A28. The current OMS has a fully integrated mobile tool, which the Overhead (OH) and Underground (UG) field employees use as an event management system to receive their trouble work assignments. This tool provides OH/UG field employees with job information, including the number of customers affected, the type of trouble predicted on the system, and corresponding AMI meter information. This mobile functionality, which exists in the current OMS, will continue to be required with the new OMS, and the current mobile solution is not compatible with the new OMS for continued use. OSI has developed the mobile Compass tool to fit this basic event management need. In addition, the Compass tool will also allow field employees access to the map view of the Network Model. In other words, the field employees will gain improved situational awareness by having access to the same Network Model as the control room employees and will have an improved understanding of the current configuration of the grid. This situational awareness will improve field safety and is included in the overall benefits described in Table 1.

Q29. Did the delays in implementing the new OMS impact DTE Electric's ability to manage customer outages with the current technology?

A29. No. The Company has continued to use the current OMS and supporting systems to manage customer outages and associated trouble per our normal trouble restoration processes. However, while the current OMS (implemented in 2003) is rapidly reaching end-of life, meaning that the vendor is no longer providing updates and is only providing limited software support, and the Company has been able to manage the grid operations in the current OMS to date, we have not been able to do so in the most efficient manner, and the investment in the new ADMS (including the new OMS, the benefits of which are described in detail below) allows the Company to mitigate the current limitations described above and improve reliability as shown in Table 1 and as previously justified and approved by the Commission for inclusion in rate base.

Q30. Can you describe the current strategy for deploying OMS and DMS?

A30. Due to the delays in the delivery of the mobile tool, the Company has modified its implementation sequence for the OMS and DMS components. Specifically, the OMS team will continue to partner with OSI on the development and delivery of variance remediation, including appropriate testing after monthly patching cycles. Variance remediation refers to the process of the ADMS vendor fixing or developing functionality in the base product and providing the Company with a patch to the current system, so the proper functionality can be achieved while utilizing the system. The Company will complete all configuration and testing on the DMS applications in parallel while the OMS work continues. Training and cutover of the OMS and DMS components will happen simultaneously for the frontline employees instead of being staggered as originally planned to allow quicker implementation of all components. In addition, the Company will be implementing a full system upgrade of the current OSI EMS shortly before the OMS cutover. The initial strategy assumed the first EMS upgrade would occur after the ADMS: DMS/OMS project was complete. However, in partnership with OSI, the Company determined the EMS upgrade was required before the OMS cutover to fully leverage all the functions in the OMS and DMS Network Model.

Q31. Why is the company upgrading the new OSI EMS that was installed in 2019?

A31. With the new delivery schedule, and in order to leverage all of the functionality OSI has implemented in the new OMS and DMS systems, the Company must upgrade the current EMS version 2016 to EMS version 2019. This is a normal process that would have occurred regardless of the OMS/DMS implementations and will continue to occur when the OSI products are fully deployed and in use in daily operations. These routine period updates allow the Company to add any new functionality, security updates, and product improvements developed by OSI (and is a standard process for all OSI customers). The technologies continue to evolve, and it is important for the Company to keep its systems current to avoid potential risk for problems and implement all security-driven upgrades.

Q32. Since a mobile solution for the field personnel is critical for OMS cutover, how will DTE Electric mitigate the risk of continued delivery delays of the mobile Compass tool?

A32. DTE Electric will leverage another field work force (field force) management software solution called ClickSoft, that is already a project included in the Company's strategic plan for OH/UG field resources. To mitigate the risk of continued delivery delays with Compass, the Company will pull up the emergent

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trouble field force management portion of the ClickSoft project into 2022, and then use the ClickSoft mobile application as the cutover-required mobile software to allow OH/UG field resources to receive trouble job assignments and details associated with those jobs. This new sequence reduces the risk of further Compass delays affecting the OMS cutover schedule, as it will allow OMS cutover to occur even if Compass is not yet fully available and will not interfere with the implementation of Compass when it is fully available, as the Company will integrate the two technologies. This allows DTE Energy to obtain the majority of the ADMS benefits in 2022 and 2023 with the implementation of the main OMS and DMS components, rather than waiting for the mobile Compass tool development. The Company will continue to plan to invest in the remaining ClickSoft functionality for planned work and additional field force functionality once Compass is implemented.

Q33. Can you elaborate on the ClickSoft work management software?

A33. ClickSoft, owned by Salesforce, is a full Field Force Management solution that is used to manage work in the field that is currently deployed and in use at the Company in the Substations organization, and will be implemented for the Electric Field Operations (EFO) organization when the new OMS goes live (replacing the current end-of-life Service Suite work management application used by EFO, as discussed in Company Witness Sharma's testimony). ClickSoft has a mobile component, ClickMobile, that can be used by field resources to receive job assignments and associated job details, plus additional field force management functions such as electronic pre-job briefs and time entry. The Company originally planned to implement the full ClickSoft package for the remaining field

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organizations within DO after the ADMS implementation was complete. This strategy included fully integrating ClickSoft and ClickMobile with OMS and the mobile Compass tool, integrating ClickSoft with the Company's current work management tool Maximo, and leveraging ClickSoft's field force management capabilities to improve the planning and scheduling processes to support both trouble and planned work. This long-term integration vision has three major benefits: first, allowing the Company to more effectively plan work for all field resources regardless of type of work (planned and emergent trouble); second, allowing dispatching personnel full visibility to all field resources regardless of type of work assigned; third, all field personnel will obtain the situational awareness benefits from Compass and the full field force management benefits of ClickSoft regardless of type of work assigned.

Q34. If the Company implements ClickSoft when the OMS is cutover, will the Company continue to invest in the Compass mobile tool with OSI?

A34. Yes. While ClickSoft will be the new mobile solution required for the OMS cutover, the Company will continue to partner with OSI on the development and delivery of the Compass mobile tool. As OSI progresses, the Company will continue work on integrating the two mobile solutions and rolling out the Compass tool to the field as planned to increase the field's situational awareness capabilities. As described above, these two mobile tools complement each other by offering the field employees a full field force management tool in ClickSoft, and the full situational awareness benefits in Compass. For example, field employees will utilize the ClickSoft tool to receive their job assignments, obtain GPS routes, conduct electronic pre-job briefs, and fill out their daily time sheets. This program

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will be integrated with the Compass mobile tool where the employees will obtain more details regarding the job assigned, and be able to see the current system configuration to determine the safest and most efficient method to restore the system.

Q35. What are the customer benefits associated with the Company's strategy to implement both Compass and the ClickSoft tools?

A35. As described above, while these two mobile products have some overlapping functionality, they are actually complimentary programs and both are needed to provide field personnel with a full field force management tool and a situational awareness tool to realize the full benefits of the ADMS. The Compass mobile tool primarily drives increased benefits in safety and situational awareness for frontline employees, and the ability to improve communication between the field and control center while responding to trouble. Specifically, Compass provides field device and electrical system status to field personnel consistent with what is seen by the System Operators and Dispatchers. This means that employees can actually see which lines are live, if circuits are jumpered together, etc, rather than having those system conditions verbally described over the phone by employees in the control room. It also provides the field employees with the ability to update device status in the Network Model to ensure proper information surrounding the status of the customers power is understood. The resulting benefit to the customer is shorter restoration times and improved response to trouble in the field as discussed earlier in my testimony and displayed in Table 1. In the future, the Compass tool will continue to mature allowing the field to have better access to the advanced DMS applications such as FLISR and SOM.

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The ClickSoft tool brings a different set of benefits to the Company and customers. In this initial implementation of ClickSoft, the largest benefit is ensuring that the cutover date for the new OMS will not be affected by any potential development delays in Compass. So, there is less risk the ADMS benefits described earlier are delayed any further. Additionally, ClickSoft brings more benefits to fruition due to its enhanced field force management capabilities. When the full ClickSoft implementation is complete, the Company will be able to have one central location to manage all work (planned and trouble), one common tool to manage all field resources, and the field will have more streamlined processes to manage their work. This will create a better understanding of total work volumes, and better opportunities to coordinate field resources for different specialties. This functionality translates into improved ability to manage both emergent trouble and the growing planned work required to complete planned investments in the grid. As stated earlier, while there is some basic overlap in functionality, these two solutions are complementary and will allow the Company to serve customers more effectively in all aspects of work.

Q36. What are the new implementation dates for the OMS and DMS components?

A36. With the exception of Compass and the SOM DMS application, DTE Electric plans to complete cutovers of the EMS upgrade, OMS, ClickSoft (for emergent work), and DMS components by the end of 2022, using these components in daily operation. As stated earlier, the Company will roll out the Compass mobile tool as soon as OSI delivers agreed upon functionality, and it is fully integrated with the ClickSoft tool. Due to the complexity of change management needed to help

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frontline employees understand and embrace the new technology and associated processes, the SOM DMS application will be technically cut over in late 2022 with the other DMS components, but will be rolled out to the frontline employees for daily operational use in mid-2023. This delay in implementing SOM will allow employees the time needed to be fully trained and understand the change impact of the new SOM processes, and will allow future maturity in the Network Model for improved data quality and increased safety.

Q37. Has DTE Electric modified the project management processes to ensure the delivery dates of the OMS and DMS components are not further delayed?

A37. Yes. As delivery issues were identified and escalated from project team to leadership and on to the steering committee, the Company took appropriate steps to mitigate these risks effectively. Examples include hiring an experienced ADMS System Integrator (Ernst & Young) in early 2020 to help manage the overall strategy, the testing process, and training development. In addition, the Company increased the cadence of touchpoints with the ADMS vendor's Executives from monthly to bi-weekly. These improvements, along with leveraging the ability to travel due to lessened COVID restrictions and continued project management cadences (weekly) to track performance, will support a successful implementation of OMS and DMS, in accord with the new timeline.

Q38. Given the delays, is it still important for DTE Electric to pursue the OMS and DMS components of ADMS?

A38. Yes. In addition to the benefits described earlier in this testimony (SAIDI improvements, end-of-life technology, seamless integration of components, automating manual processes, improved situational awareness), as mentioned in Witness Pfeuffer's testimony on prioritization of DO Strategic projects, the Global Prioritization Model (GPM) continues to rank ADMS as the top project due to its importance to the Company's plans to improve reliability for customers and modernize the grid to respond to increasing weather volatility, new technologies, and electrification. Without completing this final ADMS project, the Company will not be able to fully leverage technology investments to improve the customer experience, and the Company would still need to invest in a new OMS as the current system is reaching end-of-life.

Q39. Can you describe the funding required to complete the ADMS project?

A39. Table 2 displays the amounts presented and included in rate base from MPSC Case No. U-20561, Exhibit A-12, Schedule B5.4 for the ADMS: DMS/OMS project. In summary, the total presented for 2018-2021 was $64.7 million and the total included in rate base through the end of the test year was $58.1 million. In this instant case, Exhibit A-12, Schedule B5.4 displays the updated costs for the ADMS: DMS/OMS project and totals $83.5 million; it is important to note this exhibit only includes costs for years 2020-2023. If you include the actual historical investment for 2018 and 2019, as displayed in Table 3, the new expected investment for the ADMS: DMS/OMS project now totals $93.9 million, an increase of $29.2 million. Due to the test year ending prior to the end of the calendar year the total cost to be considered for inclusion in the rate base is $92.6 million. This still reflects the overall cost increase of about $29.2 million.

Q40. Why did the total project cost increase by $29.2 million?

A40. The overall cost increase of $29.2 million can be broken down into four components: 1) $3.7 million of planned investment was not included in the Exhibit A-12 from MPSC case No. U-20561 due to the years in scope for that case; 2) there is an additional $5 million included for an expanded ADMS Reporting project, which was not included in the original scope; 3) there is an additional $6.9 million included for the emergent trouble portion of the ClickSoft project already planned in the Company's strategic investment that is being pulled up to correspond to the OMS cutover date; and 4) the remaining $13.6 million of additional costs are associated with the ADMS: DMS/OMS project delays due to COVID and the delayed delivery of the Compass mobile tool. Based on the test years included in this instant case, the Company is seeking a total of $92.6 million to be included in rate base. Due to the test year timing (not equal to calendar year), this creates an incremental $34.5 million increase above what was previously approved for inclusion in rate base. The difference between the $34.5 million and the $29.2 million is the amount that was presented in the last rate case as the planned total spend for the project, but which was not included in rate base, because it fell outside the test year, and the exclusion of the remaining spend that falls outside the test year in this case. This is shown in Tables 2 and 3, below.

Table 2 Previously Presented ADMS: DMS/OMS Investments

ADMS: DMS/OMS investments presented in previous rate case (U-20561)

($000) Description	Historic 12 mos. ended 12/31/2018	Projected Calendar Year 12 mos. ended 12/31/2019	12 mos. ended 12/31/2020	12 mos. ended 12/31/2021	Total Investment Presented
ADMS: DMS/OMS	835	25,980	28,000	9,900	64,715

($000) Description	Historic 12 mos. ended 12/31/2018	Bridge Period 16 mos. ending 4/30/2020	Test Year 12 mos. ending 4/30/2021	Total Included in Rate Base
ADMS: DMS/OMS	835	35,313	21,967	58,115

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Table 3 ADMS: DMS/OMS Investments Presented in Instant Case

ADMS: DMS/OMS investments presented in the instant case (U-20836) plus historic investments						
	Historic	Historic	Projected Calendar Year			Total
($000)	24 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	Investment
Description	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	Presented
ADMS: DMS/OMS	10,392	19,393	21,928	34,138	8,089	93,940

	Historic	Historic	Bridge Period	Test Year	Total to be
($000)	24 mos. ended	12 mos. ended	22 mos. ending	12 mos. ending	Included in
Description	12/31/2019	12/31/2020	10/31/2022	10/31/2023	Rate Base
ADMS: DMS/OMS:	10,392	19,393	50,377	12,430	92,592

As seen in Table 2. the difference between what DTE planned to spend on this project and what fell in the last projected test year was $6.6 million ($64.7 million planned - $58.1 million included in rate base). As seen in Table 3, the difference between what DTE plans to spend on this project and what falls within this projected test year is $1.3 million ($93.9 million planned - $92.6 million to be included in rate base). When the previously planned and presented $6.6 million is added to the $29.2 million in incremental spend, and the $1.3 million that falls beyond the 2022-2023 projected test year is subtracted, the total proposed increase to rate base in this case for this project is $34.5 million ($29.2 million - $1.3 million + $6.6 million).

Q41. Can you elaborate on the ADMS Reporting project included in the total costs for ADMS?

A41. The Company relies upon the Data that resides in the OMS system to make critical decisions daily and especially during storm events. With the implementation of a new OMS system, the data and capabilities that other interfaced solutions can subscribe is changing. As a result, there are multiple Reports, Dashboards and support systems that have been created over time that use the data created by the

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OMS and must be updated to connect to the new OMS solution. The existing tools were examined, and the Company made the strategic decision to leverage Cloud computing technology to store and build all of the reports and applications that support daily operations and use data sourced from the OMS. The first step in this project includes transferring appropriate data from the on-premise Outage Data Warehouse (ODW), which is a direct extract from the ADMS, to the Data Lake in the Cloud where the OMS data can be accessed by approved reports and combined with data from other sources. The second step of this project includes identifying all current reports that utilize data created by the current OMS, and evaluating how to streamline the reports to improve accuracy and appropriate availability within the Company. The third component includes building all new operational reports in the Cloud which can seamlessly access the data from the new ADMS and other source systems to allow operations to better serve our customers. Examples of these reports include customer location history that displays a summary of historical work at a location so the field employees and engineers can assess key trouble areas and generate plans for improved reliability. Other examples include Storm reporting tools and applications (such as ChatBot which is described in Company Witness Sharma’s testimony), and real-time operational reports used by the field employees and the ESOC to better manage trouble volume.

Q42. Why wasn’t the Reporting workstream included in the original scope of the ADMS project?

A42. When the original ADMS project was scoped, the Company assumed a nominal investment in reports associated with ADMS data. The original plan included using the current operational reports in the future, and simply changing the source for the

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data obtained from the OMS. As the OMS project developed, the Company was able to more completely assess the current state of its operational reporting and support systems. This understanding highlighted an opportunity to bring all of those systems and reports into a consolidated method including updating those systems to new tools and methods that better serve the needs of the employees that use those systems to manage Customer restoration. At that same time, between the initial 2017 ADMS project inception and the end of 2019 when this decision was taken, the Company learned more about the rapidly evolving benefits of Cloud computing and made the strategic decision to move its IT investments in that direction for all future development for which the Cloud approach is consistent with safety or regulatory standards. This full understanding of the current systems and strategic change in Cloud computing were not understood nor included in the original scope of the project.

Q43. What benefits will the customer gain with this additional investment in ADMS Reports?

A43. Many of the current reporting tools that generate the operational reports utilized daily are reaching end-of-life or are housed on servers which are reaching end-of-life. The reports need to be upgraded before failure to ensure accurate input into current processes. In addition, these updated ADMS reports will allow the Company to improve accuracy and response to emergent issues reported by customers.

System Operations Center (SOC) Modernization

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Q44. Was the SOC Modernization project cost included and approved for recovery in DTE Electric's previous rate case?

A44. Yes. The SOC Modernization project was addressed in depth by Company Witness Bruzzano in both MPSC Case No. U-20162 and MPSC Case No. U-20561, and the expenditures for the project were approved for recovery by the Commission in both cases. Regarding SOC Modernization, the Commission noted in its May 2, 2019 order in U-20162 on page 30 that: "The Commission stresses the need for and importance of this modernization project for system operations from a reliability and resiliency standpoint." In addition, in MPSC Case No. U-20561, Exhibit A-12, Schedule B5.4 the Company presented total projected expenditures of $109.4 million for years 2018-2021. Following these previous cases, the Commission has approved a total of $106.9 million be included in the rate base.

Q45. What is the SOC Modernization project?

A45. The SOC Modernization project is aimed at replacing the Company's outdated primary SOC and the smaller, outdated backup SOC by constructing two facilities designed using current industry security, resiliency, and operability standards. The existing SOC and backup SOC have significant limitations, which I will describe later in my testimony.

Q46. What functions does the SOC perform?

A46. The SOC is the most critical facility in Distribution Operations. Personnel in the SOC operate the subtransmission and distribution system in southeast Michigan and support generation operations. They monitor alarms and system conditions, and direct field personnel to operate electrical equipment for routine switching

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needed for maintenance, other planned activities, and for outage restoration. SOC System Supervisors are the ultimate authority for the DTE Electrical system operation with the goal of maintaining safety of the field personnel and public, reliability of the electrical grid and the continuity of service to the customers. The SOC also interfaces with Central Dispatch personnel to ensure appropriate crews are assigned to address system issues.

Q47. Why is the SOC Modernization project needed to replace the existing SOC facility?

A47. The existing SOC poses several limitations, which DTE Electric identified through extensive benchmarking at the inception of this project:

- Outdated facility: The facility lacks the redundancy in mechanical and electrical systems that is necessary to ensure continued operations in the event of a crisis.
- Outdated technology: The SOC utilizes a magnetic tile board representation of the electric network, as opposed to an electronic display board of the transmission, subtransmission, and distribution network that is now common in the industry. This severely limits situational awareness, which is critical to understand the current status of the system. The tile map board, located on a vertical wall inside the facility, is also running out of space to accommodate growth and limits training opportunities. Whenever a change occurs on the system, which happens many times per day, an employee must manually mark open and shut circuits by placing a magnetic marker on the wall with a 20+ foot pole.

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- Space limitations: DTE Electric's SOC and dispatch personnel are physically separated, causing the use of repeated phone calls to communicate. The colocation of SOC and dispatch personnel is a well-established industry best practice and provides customer benefits in terms of improved speed to resolve trouble.
- Limited visibility of telecommunication infrastructure performance: The reliability of the telecommunication paths from field devices to the SOC is critical for the effective monitoring of the grid and remote operations. Developing the ability to separately monitor the condition of the telecommunication network through the construction of a Network Operations Center (NOC) is part of the SOC Modernization project.

Q48. What was the original timeframe for the new Electric System Operations Center (ESOC) and the new Alternate System Operations Center (ASOC)?

A48. The SOC Modernization project was initiated in 2017, with a planned completion and occupancy of ESOC by December 2019 and ASOC by December 2020.

Q49. What progress has been made on the construction of the new ESOC?

A49. The design for the new ESOC was completed in April 2019, contractors were mobilized in May, and the groundbreaking for the new ESOC was held on May 28, 2019. To date, construction of the new ESOC is complete, Central Dispatch (Dispatchers and support personnel) and about half of the Operational Engineering employees are now working in the space, and IT is installing the remaining equipment as described in further detail later in my testimony.

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Q50. Were there any delays in the construction of the new ESOC?

A50. Yes. The SOC Modernization project was initially delayed in 2018 due to ESOC building design adjustments and permit timing, which pushed the groundbreaking to May 2019 as described above. The new ESOC experienced some delays in the beginning of construction which resulted from discovery of below-grade obstructions and environmental remediation. However, COVID caused the largest delay for ESOC construction. The project was completely shut down for approximately two months due to availability of construction workforce, as both the company and contractors developed and implemented new COVID-related health protocols in consultation with state and local officials. Once construction resumed, COVID work restrictions, associated with worker social distancing, reduced efficiency for approximately fourteen additional months. COVID also caused material delays in mechanical and electrical systems due to the availability of microchips.

Q51. What are the costs associated with building the new ESOC?

A51. In MPSC Case No. U-20561, Exhibit A-12, Schedule B5.4, the total costs the Company presented for the SOC Modernization project was $109.4 million for 2018-2021. Table 4 displays the amounts presented in MPSC Case No U-20561 plus the historical investment from 2017 previously displayed in MPSC Case U-20162, Exhibit A-12, Schedule B5.4. This indicates a total projected investment of $110.7 million for the SOC Modernization project, with $106.9 million previously approved to be included in rate base due to test year calculation. The SOC Modernization project originally consisted of two new facilities, the ESOC and ASOC, with an expected distribution of $78 million and $33 million respectively.

In this instant case, Exhibit A-12, Schedule B5.4, the Company displays the ESOC and ASOC facilities on two separate lines for years 2020-2023. The ESOC costs presented total $65.9 million and the ASOC totals $34.5 million. Table 5 displays the amounts presented in this instant case plus the historical investment for previous years to show the new total costs associated with these two projects. The new total cost for the ESOC is $98.5 million (historic 2017-2020 plus projected 2021 and 2022 investments), indicating an increase of $20.5 million over the original projected investment. The new total costs for the ASOC is $34.5 million, indicating only a slight increase of $1.5 million over the original plan submitted for approval. As displayed in Table 6, the total increase in costs for the two facilities is $22.1 million for the years 2017-2023, to be included in rate base. The increased cost of the ESOC was driven by the construction delays due to COVID and several other items described below. The Company is proposing to include an incremental $22.1 million in the rate base.

Table 4 Previously Presented SOC Modernization Investments

SOC investments presented in previous rate case (U-20162 & U-20561)						
	Historic	Historic	Projected Calendar Year			Total
($000)	12 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	Investment
Description	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	Presented
SOC Moderization	1,223	4,460	36,100	63,300	5,600	110,683

	Historic	Historic	Bridge Period	Test Year	Total
($000)	12 mos. ended	12 mos. ended	16 mos. ending	12 mos. ending	Included in
Description	12/31/2017	12/31/2018	4/30/2020	4/30/2021	Rate Base
SOC Moderization	1,223	4,460	57,200	44,067	106,949

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Table 5 SOC Investments Presented in Instant Case

SOC investments presented in the instant case (U-20836) plus historic investments						
	Historic	Historic	Projected Calendar Year			Total
($000)	36 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	Investment
Description	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	Presented
SOC: ESOC	32,624	51,463	14,062	369	0	98,518
SOC: ASOC	-	-	577	9,982	23,967	34,526

	Historic	Historic	Bridge Period	Test Year	Total to be
($000)	36 mos. ended	12 mos. ended	22 mos. ending	12 mos. ending	Included in
Description	12/31/2019	12/31/2020	12/31/2020	10/31/2023	Rate Base
SOC: ESOC	26,941	51,463	14,369	62	98,518
SOC: ASOC	-	-	8,895	21,636	30,531

Table 6 Change in SOC Investments

Change in SOC investments			
		Total	Total to be
($000)		Investment	Included in
Description	Case(s)	Presented	Rate Base
SOC Moderization	U-20162 & U20561	110,683	106,949
SOC: ESOC	U-20836	98,518	98,518
SOC: ASOC	U-20836	34,526	30,531
Increase		22,361	22,100

Q52. Can you further explain the issues causing the increase in budget to complete the ESOC?

A52. Yes. In addition to the costs incurred for construction delays caused by COVID, there were other cost increases to the ESOC project since the Company filed MPSC Case No. U-20561. These cost increases were driven by the following items: an increase in square footage, additional testing and permitting, and a new IT datacenter with additional integration efforts. Descriptions of these impacts can be found in the following questions.

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Q53. Why was the square footage of the ESOC increased from the original design?

A53. When the SOC was proposed in MPSC Case No. U-20561, the original design was approximately 42,000 square feet, and was intended to allow co-location of the system operators from the existing SOC Control Room with the dispatchers from the existing Central Dispatch. As the Company continued to evaluate the learnings from benchmarking other utilities, DTE Electric determined that additional benefits could be realized if critical support personnel were also co-located within the ESOC. To accommodate these additional resources, the square footage of the ESOC needed to increase. The square footage of the final design was 21,000 square feet larger than the original design, totaling 63,900 square feet, to allow for the revised plan to co-locate all required personnel.

Q54. Why is co-location of additional critical support staff important?

A54. The additional co-location of critical support personnel is to increase efficiency and collaboration among these employees and other Control Room staff. The Company is defining critical support personnel as the Operational Engineering (OE) workgroup, and the SCADA Realtime Support (SRS) workgroup. We know that it is far more efficient to have all critical personnel who work on Control Room processes in the same facility. These technical workgroups are an integral part of operations in the Control Room and including them in the co-location effort further enables the use of the ADMS tools by the Control Room personnel to better serve customers. In addition to the co-location of the support personnel, several collaboration rooms and an emergency operations room were added to enable the efficient restoration of customers whenever a significant event occurs on the system. Also, the ESOC was equipped with a training area that will enable the incorporation of lessons learned into operations personnel day-to-day training. We know this is consistent within the utility industry due to the benchmarking results conducted and described in detail in Company Witness Bruzzano's testimony in MPSC Case No. U-20162 and MPSC Case No. U-20561. The current primary SOC is located across two connected buildings and spans four floor levels. It is approximately 40,000 square feet, including the separately located Central Dispatch and Operations Engineering workgroups. This means that when system changes occur and adjustments need to be made to respond accordingly, the employees needed to coordinate activities may be located in multiple places and must rely upon calling or emailing one another to give direction rather than collaborating in the same location. Similarly, the current backup SOC has approximately 5,000 square feet and the same constraints of not allowing the Company to co-locate personnel effectively. The new ASOC was also scaled up and is planned to be approximately 19,300 square feet. Both facilities are designed to reduce the current inefficiencies associated with not having critical functions co-located. With the decision to co-locate these additional critical support resources, the number of employees that would be accommodated at the ESOC rose by approximately 60, which in turn drove an increase in IT costs for that same number of computers, monitors, peripherals and their associated infrastructure, including the labor to provision and install that equipment.

Q55. Why was there additional testing and permitting versus the assumptions made in the original ESOC scope?

A55. Independent quality testing for concrete, including caissons and foundations, steel, roofing, and soil is required by the International Building Code, which has been adopted by the State of Michigan to obtain the necessary permitting. As the project scope development progressed, the Company identified the scope of this work was underestimated and the final costs were higher than what was expressed in Company Witness Bruzzano's testimony in the previous MPSC Case No. U-20561.

Q56. How did the IT Datacenter with additional integration efforts increase for the ESOC project?

A56. When the SOC Modernization project was originally scoped, there was an option to either serve the ESOC from a fully contained Datacenter incorporated within the new facility, or from an external datacenter within the Corporate headquarters. The original estimates reflected the option to serve the facility from an external source within the Corporate Headquarters. While this option included a datacenter footprint, it was not fully built out, so foundational infrastructure was included such as cabling, workstations, internal network and power, yet the estimate did not include the complete material requirements for a fully isolated network-ready facility including an integrated, dedicated, datacenter. After the ESOC project began, it became clear that to achieve the desired level of disaster tolerance needed to ensure that the new facility would remain operational during significant events, the other option with an integrated datacenter and network isolation design would be required. Based upon this assessment and decision, the fully integrated datacenter option was pulled into scope for the construction of the ESOC. The fully integrated datacenter brought with it additional material investments for that location including HVAC, Equipment racking, cabling, servers, storage, and all of

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the other support equipment needed to activate a modern datacenter for this facility while meeting all of the NERC certification requirements. This increased the level of investment needed to achieve the updated design required.

Q57. What steps remain before the new ESOC is fully operational?

A57. ESOC construction and the implementation of its IT systems are largely complete. The Central Dispatch employees, and most of the other ESOC support personnel, have moved into the new facility for daily operations. The only remaining items to be completed are related to the NERC aspects of the facility and include turning on the NERC Physical Perimeter Barrier, activation of Electronic Security Barriers, separation of EMS/GMS applications, and the formal NERC certification of the control room. Formal NERC certification is required before the Control Room Operators may move into the ESOC and operate the EMS system in day-to-day operations. The Company is on track to complete these last items and be fully operational by the end of the first quarter 2022.

Q58. Is a new backup facility still needed for the ESOC?

A58. Yes. The reasons for building a new modernized backup facility have not changed since the Commission approved building a new ASOC in MPSC Case No. U-20561. As stated in Witness Bruzzano's testimony in MPSC Case No. U-20561 (4T 199), given the critical nature of the ESOC in operating the electric infrastructure, a backup facility is required in the event the primary facility is inoperable. The existing backup facility is inadequate for sustained operations and for disaster recovery efforts. Though it does meet minimum regulatory requirements for NERC regulated Balancing Authority and Generator Operator

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tasks, nevertheless managing the distribution system and recovering from a storm or other disaster from the existing backup SOC would be extraordinarily challenging and delay restoration of the distribution system. The new backup SOC, also known as the ASOC, will have the appropriate square footage required to co-locate personnel and will have the appropriate mechanical and electrical system redundancies, as discussed previously in my testimony. 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. 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 is used in the current backup facility. The planned location of the new ASOC has shifted from a site near the existing backup SOC, to be connected to the new Waterford Service center (as discussed in Company Witness Uzenski's testimony). The ASOC will be located approximately 25 miles away from the new ESOC and will allow the Company to safely operate the grid in the case of a major adverse event at ESOC. Having both a primary and alternate location to operate the grid is a NERC requirement to be able to operate the electrical system and to recover from a catastrophic event safely and quickly.

Q59. Why did the Company decide to move the location of the ASOC?

A59. As previously indicated, the ASOC was still in its conceptual design phase when MPSC Case No. U-20561 was submitted. Once the Company obtained a full design with appropriate requirements, the forecasted costs were significantly higher than what was initially presented. By constructing the ASOC at the same location as the new proposed Waterford service center, the Company will be able to leverage synergies in construction and reduce overall costs closer in alignment to the initial estimates provided in MPSC Case No. U-20561. This new location still allows the control room to relocate in case of an emergency in a reasonable amount of time to not affect operations, and the shared space in the new service center will allow for the co-location of the critical support staff as well.

Q60. What progress has been made on the new ASOC facility?

A60. In 2020, the ESOC and ASOC were split into separate projects. This was due to the delay in the overall SOC Modernization project, the decision to move the location of the ASOC to leverage the planned construction of the Waterford service center, and to the new timing of the ASOC construction. At present, the ASOC project is in the planning and conceptual design phase.

Q61. What costs for the new ASOC were already approved in rates?

A61. As discussed earlier in my testimony, in MPSC Case No. U-20162 and MPSC Case No. U-20561, both the ESOC and ASOC were included as one line item titled SOC Modernization in Exhibit A-12, Schedule B5.4. The Company presented a total cost of $109.5 million, resulting in $106.9 million approved for inclusion in the rate base for both facilities based on the test case years. This total included $33 million for the conceptualized ASOC facility costs.

Q62. What are the current cost requirements of building the new ASOC?

A62. In this instant case, the Company has separated out the cost of ESOC and ASOC in the Exhibit A-12, Schedule B5.4, where the Company is presenting the revised conceptualized cost for ASOC totaling $34.5 million in 2021-2023, which is a slight increase over the original conceptualized cost of $33 million. These totals can also be referenced in Table 5 for comparison. The cost associated with ASOC is in addition to the costs associated with the Waterford service center as described in Company Witness Uzenski's testimony. As previously discussed in my testimony, Table 6 displays the comparison in total costs between rate cases. The Company is proposing to include an incremental $22.1 million in the rate base.

Q63. How will customers benefit from the total SOC Modernization project?

A63. As described earlier in my testimony, the SOC Modernization project consists of building two facilities, ESOC and ASOC, to address the current limitations in the current facilities. Customers will benefit from the improved communication paths between the resources that will be co-located in the new facilities, which will facilitate quicker and improved coordination to create and implement restoration strategies more effectively. Plus, customers will benefit from reduced risk in disruption in operations during outage events, and faster restoration times regardless of the facility from which the System Operations organization is forced to operate. The ability to understand system conditions and dispatch resources to address issues will be greatly enhanced by the technology available in the new facilities and the co-location of the system operators, dispatchers, and support personnel. In addition, ESOC will be more resilient and hardened to withstand adverse natural and man-made disasters, allowing electric grid operations to recover much more quickly in the event of a major catastrophe.

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Q64. Did the delays in construction of the new ESOC and ASOC disrupt DTE Electric's ability to manage power outages and other system issues such as equipment failures in the field?

A64. No. The Company has continued to effectively manage the grid operations in the current facilities following established procedures to coordinate resources and monitor the grid. However, while the Company has been able to manage the grid operations in the current facilities to date, we have not been able to do so in the most efficient manner, and the investment in the two new facilities allows the Company to mitigate the current limitations described above and improve reliability as previously justified and approved by the Commission.

Q65. Does this complete your direct testimony?

A65. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KEEGAN O. FARRELL

<u>**DTE ELECTRIC COMPANY**</u>
<u>**QUALIFICATIONS AND DIRECT TESTIMONY OF KEEGAN O. FARRELL**</u>

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<u>No.</u>

Q1. What is your full name, business address and by whom you are employed?

A1. My name is Keegan O. Farrell (he/him/his). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company) as the Manager of Demand Response.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from Michigan State University with a Bachelor of Arts Degree in Communication. In addition, I received a Master of Science Degree in Decision Technologies from the University of North Texas.

Q4. What is your professional experience?

A4. From 2008 until 2012, I was employed by DTE Gas Resources, LLC in Fort Worth, Texas where I held positions of increasing responsibility, ultimately serving as a Decision Support Analyst. In this role, I was responsible for assisting with calculating reservoir economics, monitoring daily oil and natural gas production, and overseeing the compliance and emission calculations for the Environmental Protection Agency's Greenhouse Gas Reporting Program (Subpart W). In 2012, I joined DTE Energy as a Senior Business Financial Analyst – Load Research. In 2014, I was promoted to Principal Financial Analyst – Load Research. In this position, I was responsible for developing and implementing statistical sampling programs used to evaluate customer class usage characteristics, developing allocation schedules for use in cost-of-service studies and rate design, and for measuring and evaluating demand response programs offered by the Company.

Q5. What is your current position?

A5. In 2018, I accepted the position of Supervisor Program Management – Demand Response and in 2021 I was promoted to Manager of Demand Response. In this position, I oversee the DTE Demand Response (DR) portfolio, which includes electric and gas DR. I am responsible for the short- and long-term strategic development and implementation of DR pilots and programs.

Q6. Do you currently participate in any industry associations?

A6. Yes. I am the course coordinator for the Association of Edison Illuminating Companies (AEIC) Fundamentals for Load Data Analysis course. In addition, I represent DTE Energy on the board of the Peak Load Management Alliance (PLMA).

Q7. Have you received industry related training?

A7. Yes. I have completed the AEIC Fundamentals of Load Data Analysis course. I have also attended various courses at Michigan State University Institute of Public Utilities Annual Regulatory Studies Program as well as the Demand Response Fundamentals and Evolution Course presented by the PLMA.

Q8. Have you testified previously before the Michigan Public Service Commission?

A8. Yes. I have sponsored testimony and exhibits before the Michigan Public Service Commission (MPSC or Commission) in the following DTE Electric cases:

Case No.	**Description**
U-18014	DTE Electric 2016 General Rate Case
U-18255	DTE Electric 2017 General Rate Case
U-20162	DTE Electric 2018 General Rate Case
U-20471	DTE Electric 2019 IRP
U-20521	DTE Electric 2017-2018 Demand Response Reconciliation Case
U-20793	DTE Electric 2019 Demand Response Reconciliation Case
U-21044	DTE Electric 2020 Demand Response Reconciliation Case

Purpose of Testimony

Q9. What is the purpose of your testimony?

A9. The purpose of my direct testimony is to discuss the development of DR efforts that DTE Electric is conducting and provide support for the expenditures and activities associated with the continuation of existing programs and pilots, and the Company's proposals for new pilots. In addition, I discuss proposed changes to demand response tariff language and customer penalty revenues from underperformance during DR events.

Q10. Are you sponsoring any exhibits in the proceeding?

A10. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.6	Capital Expenditures – Demand Response Portfolio and DTE Insight (page 1, lines 1-

		4 and page 2, lines 1-15)
A-12	B5.6.1	Peak Time Savings Pilot Document
A-12	B5.6.2	Battery Storage Pilot Document
A-12	B5.6.3	Residential Generator Pilot Document
A-12	B5.6.4	Residential Window A/C Pilot Document

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes, they were.

Q12. How is your testimony organized?

A12. My testimony consists of the following five parts:

Part I	Demand Response Portfolio
Part II	Interruptible Air Conditioning Program
Part III	Programmable Controllable Thermostat Program
Part IV	Bring-Your-Own-Device Program
Part V	Other Demand Response Programs and Pilots
Part VI	Demand Response Customer Penalty Revenues

<u>Part I: Demand Response Portfolio</u>

Q13. What is the overall purpose of the DR programs and pilots that the Company is managing and investing in?

A13. The Company has been managing and investing in a diverse range of programs and pilots that serve as resources in the Company's integrated resource planning. Significant changes have been occurring in the energy landscape in the State of Michigan including, energy legislation, regulatory framework, and environmental

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regulations. These changes, coupled with a shift from fossil fuel-based generation to renewable generation, are driving investment in a DR portfolio to support resource adequacy. DR programs are, and will continue to be, an important part of DTE Electric's integrated resource portfolio. The Company's DR programs are being designed and managed to help reduce enrolled customers' energy use during peak hours. The reduction in customer usage from DR programs provide value to both the utility and the customer through reduced capacity costs, and in turn, can provide lower bills or incentives for customers utilizing the programs.

The DR programs are part of a utility system framework within the comprehensive context of an Integrated Resource Plan (IRP) process. DTE Electric develops, validates, and manages these programs, which offer customers a range of options consisting of products, customer incentives, tariff structures, and education based on their profiles and customers' willingness to curtail energy usage during peak hours. As part of the development process, the internal DR organization evaluates programs and pilots, customer behavior, program acceptance and validates technologies that can deliver benefits to utility customers. A portfolio of functioning programs enabled the Company to continue providing secure, reliable, and sustainable energy supply to its customers under a changing generation capacity and energy landscape and will continue to do so in the coming years.

Q14. Is the evaluation and cost recovery of Demand Response investments governed by a specific regulatory framework?

A14. Yes. The investments in DR are evaluated under the three-phase framework approved by the Commission in Case U-18369 on September 15, 2017.

Q15. Could you describe the regulatory framework adopted by the Commission to approve, recover, and reconcile expenditures in the Company's DR portfolio?

A15. Yes. The Commission adopted the Staff's recommendation of a "three-phase" approach with some modifications. The three-phase approach is a multi-step process which evaluates DR proposals in the context of the IRP in the first phase. After DR plans are approved as part of the IRP, the DR program costs are considered approved, and are included in rates in the utility's next general rate case during the second phase. The utility can propose changes to its DR programs or pilots that can be evaluated and approved in general rate cases or demand response reconciliation filings and later included in the following IRP. The third phase involves a reconciliation of the DR costs, participation rates and demand savings achieved on an annual basis. The Commission also stated that during the reconciliation proceedings, actual capital spending in the examination period will be reconciled against the amount approved in the IRP and recovered in the rate case, while Operation and Maintenance ("O&M") spending will be reconciled against the amount approved and recovered in the general rate case.

Q16. Is the evaluation and cost recovery of the investments in the DTE Electric's DR portfolio subject to the framework approved in the Commission's Order in Case No. U-18369?

A16. Yes. The Commission approved a multi-year proposal presented by the Company with modifications in its Order on April 15, 2020 in the Company's IRP Case No. U-20471. This approval constitutes the first phase in the three-phase framework described above as related to the DR capital investments specifically included in

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the bridge period of January 1, 2021 through October 31, 2022, and the projected test year November 1, 2022 through October 31, 2023. The instant proceeding represents the second phase in the DR three-phase framework. Accordingly, DTE Electric requests that the approved DR capital costs from its recent IRP and the associated O&M for those programs and pilots be included in rates. In addition, as provided in the Commission's Order in Case U-18369, the Company is proposing changes to its DR programs and pilots. This is intended to support the timely evaluation and approval in this rate case proceeding for future inclusion in a subsequent IRP, which is due to be filed no later than September 1, 2023.

Q17. What DR programs and/or pilots were approved in the Company's last IRP?

A17. In the 2019 order in case U-20471, the MPSC approved capital expenditures associated with the interruptible air conditioning (IAC) switches and the programmable communicating thermostats (PCTs), and the Bring-Your-Own-Device (BYOD) pilot[1] and the Electric Power Research Institute (EPRI) pilot. Each of these programs are discussed later in my testimony.

Q18. Could you provide an overview of the Company's current DR portfolio?

A18. Yes. The Company currently has an established DR portfolio, which combines a diverse set of programs for residential, commercial, and industrial customers. In addition, the Company continues to invest in various pilots to enhance the current portfolio offerings as well as leverage new technologies. The goal of the Company's DR programs is to deliver accountable peak demand reduction and customer engagement. Pilots are potential programs focused on understanding

[1] In 2019, BYOD was considered a pilot, but is now a program in the Company's DR portfolio.

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technology or design and to determine whether they are capable of becoming full-scale programs that will deliver accountable peak demand reduction. Pilots can eventually become programs in the Company's DR portfolio if they prove to be successful.

Another classification used to define the type of program is whether the program is dispatchable or non-dispatchable, which are distinguished by the reason for the action. A dispatchable program is one in which an action is taken in response to requests or "calls" from a utility. The dispatch may be communicated directly to connected devices or to designated energy managers, who modify operations. Often, there are non-performance penalties or other conditions designed to increase customer compliance. Examples of dispatchable programs in the Company's portfolio include direct load control of air conditioning units or interruptible tariffs for Commercial and Industrial customers. On the other hand, a non-dispatchable program is one in which voluntary actions are taken by the customer to reduce or shift demand from peak to non-peak periods. Time-of-use rates are an example of non-dispatchable DR. With time-of-use rates, the prices customers pay vary based on the time of day to reflect the varying cost to supply, typically higher during peak hours and lower during non-peak hours. In order to reduce load during peak hours and thereby reduce their overall cost, customers may voluntarily shift their usage to the lower rate non-peak hours.

Q19. How much capacity does the Company's existing DR portfolio account for in meeting MISO's resource adequacy requirements?

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A19. For the 2021/2022 MISO Plan Year, DTE registered a total of 749 MWs of demand response resources as Midcontinent Independent System Operator (MISO) Load Modifying Resource (LMR) to meet resource adequacy requirements and is broken out by program in Table 1.

Table 1 DTE Electric Load Modifying Resource Program Registered Capacity

Program	**MW (ICAP[2])**
R10 Interruptible Supply Rider	304
D1.1 Interruptible Space Conditioning	174
D8 Interruptible Primary Supply Rate	103
R1.2 Process Heat Rider	63
D3.3 Interruptible General Service	13
R12 Capacity Release	33
R1.1 Metal Melting Rider	3
Bring-Your-Own-Device (BYOD)	55
Total	**749**

Q20. How much has the Company invested in the DR portfolio?

A20. The Company spent $5.9 million in capital expenditures associated with the DR portfolio in 2020. Shown in Table 2 is the Company's historical capital expenditures from January 1, 2020 through December 31, 2020 by program. At the time of the filing of DTE Electric's instant rate case, the capital expenditures as well as the O&M expenses associated with the DR portfolio for the calendar year 2020 are subject to the ongoing reconciliation proceeding under Case No. U-21044. The

[2] ICAP (Installed Capacity) values are used by MISO for their resource adequacy requirements.

referenced DR reconciliation case corresponds to the third phase described above of the three-phase framework approved by the Commission in Case No. U-18369.

Table 2 – Historical DR Capital Expenditures 2020

Programs *($ Thousand)*	**Historical 12 Mo. Ended 12/31/2020**
Interruptible Air Conditioning (IAC) Program	$1,624
Programmable Controllable Thermostat (PCT) Program	$2,599
Other DR Pilots[3]	$1,704
Total – DR Portfolio	**$5,927**

Q21. How much is the Company forecasting to invest in the DR portfolio during the bridge period of January 1, 2021 through October 31, 2022, and the projected test year November 1, 2022 through October 31, 2023?

A21. The Company is forecasting to invest capital expenditures in the DR portfolio in the amount of $19.9 million for the bridge period of January 1, 2021 through October 31, 2022, and $9.7 million for the projected test year beginning on November 1, 2022 and ending on October 31, 2023. A breakdown of these capital expenditures is shown in Exhibit A-12, Schedule B5.6, Page 1 of 2. In addition, the Company is forecasting to spend $2.7 million in operation and maintenance (O&M) expenses in support of the DR programs and pilots. The associated O&M expenses are shown in Company Witness Burns' Exhibit A-13 Schedule C-5.9, line 9. The

[3] Other DR Pilots include BYOD pilot, Peak Time Savings (PTS) pilot, as well as storage pilots

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Company is planning to continue investments in the IAC, PCT, and BYOD programs, as well as continuing to invest in other DR programs and pilots.

Q22. How do the O&M expenses support DR programs?

A22. The estimated expenses of $2.7 million represent the funding needed to support the marketing, operation, and development of the portfolio of programs and pilots, including staffing requirements to manage and monitor the existing portfolio, software and technology to effectively run the programs and targeted customer incentives.

Q23. Is the Company planning to increase the annual projected O&M expenses versus the expenditure levels from prior annual periods?

A23. Yes. As some of the prior pilots transitioned to programs in the recent years, the Company is focusing its material and human resources on the operation and maintenance of those programs. Given the nature of these operation and maintenance activities, the associated expenditures are considered O&M expenses from an accounting perspective. In addition, external platform solutions that utilize cloud technology are considered s software-as-a-service procurement and are considered an O&M expense. The Company expects that this kind of technology solution and type of service supply will become more prevalent for programs and pilots in the future.

Q24. Is the DTE Insight Program and associated spend a component of the Company's DR portfolio?

A24. No. DTE Insight is a stand-alone program developed around a mobile application that aims to drive customer behavior with the goal of reducing both overall energy (gas and electricity) consumption and electricity demand during peak hours. The DTE Insight program is discussed in the testimony of Company Witness Thac Nguyen.

Part II: Interruptible Space Conditioning Program

Q25. What is the Interruptible Space Conditioning program?

A25. The interruptible space conditioning program, commonly referred to as the IAC program or CoolCurrents™ is a dispatchable DR program, in which a direct load control device (LCD) is installed on a customer's air conditioning unit or central heat pump in exchange for a discounted energy charge on the associated usage. The Company is offering the IAC program under the Tariff D1.1 Interruptible Space Conditioning Service Rate.

Q26. What is the status of the Company's IAC LCD replacement program?

A26. Since the Company started replacing legacy LCDs in 2017, the Company has successfully replaced a cumulative total of 166,568 units as of October 31, 2021, with a goal of replacing approximately 214,000 by the end of the projected test year.

Q27. Why is the Company continuing to make these improvements?

A27. The Company has identified that replacing the outdated infrastructure results in a higher capacity value through increased capabilities and effectiveness. The Company has increased the MISO acknowledged capacity on the IAC program as the replacement of the older technology is occurring. The Company is currently claiming 174 MWs of available capacity for the program in 2021 as shown previously in Table 1. With continuous investment in the IAC program, DTE is able to extend the equipment life as well as increase the available capacity in MISO, all while continuing to provide an additional demand response program option for residential and commercial customers.

Overall, continuous investment in the IAC program remains appropriate because DTE Electric intends to upgrade the infrastructure and extend the equipment life while increasing the available capacity in MISO.

Q28. Has the Company found any technical issues during the recent installation activities?

A28. Yes. The Company found that some of the legacy LCD switches or Radio Control Units (RCUs) are no longer connected by the necessary 24v wiring that powers the switch. Without this wiring, a new LCD switch will not operate. In order for the equipment to become operational, an electrician will have to repair the wiring to accommodate the control unit.

Additionally, a software upgrade applied in late 2020 caused approximately 25,000 new LCDs to be manually reset. The Company chose to focus on resetting these units in early 2021 rather than continue to install new LCDs. This contributed to the Company missing its goal of installing 24,000 units in 2021 or having approximately 180,000 switches replaced by year-end 2021.

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Q29. Is the Company addressing the technical installation issue in some of the customers' legacy switches?

A29. Yes. DTE is evaluating options to address sites where the 24v line is inoperative. The two main options under consideration include a proactive campaign requesting the customer repair the wiring and notify the Company when the work is completed, and an identification of alternative wired LCDs that are not dependent on customers' upgrade to a 24v line. These two options are part of the planned efforts that the Company is embarking to finalize the complete program replacement by the end of 2024.

Q30. Has the Company encountered any other issues with IAC program?

A30. Yes. The Company is seeing attrition in the IAC program due to the evolvement of technology and other DR programs, such as the smart thermostat programs. Moving forward, the Company is exploring new opportunities to educate current IAC customers on the benefits of continued participation on the IAC program as well as exploring opportunities to enroll new customers on the program. In addition, a portion of legacy LCDs previously were not replaced as installers could not access the LCDs for various reasons These issues are now being addressed and customers are being given the opportunity to schedule their LCD replacement.

Q31. What are the Company's planned efforts in managing the IAC program?

A31. Under its long-term IAC capital improvement plan, DTE Electric has installed new devices and is planning to purchase and install additional devices. The cumulative total of installed LCDs was 166,568 as of October 31, 2021. Table 3 below details historical and projected installations.

Table 3 – Historical and Projected IAC LCD Installations

	Historical 12 Mo. Ended 12/31/2020	Projected 12 Mo. Ending 12/31/2021	Projected 8 Mo. Ending 10/31/2022	Projected 12 Mo. Ending 10/31/2023
Ending Balance	158,212	170,212	190,212	214,212

The Company is managing the upgrade with a commensurate rate of unit purchases while the installation work progresses throughout the bridge and projected test periods. It is expected that those acquired units will be installed throughout the respective periods while maintaining an adequate volume of units in inventory. Concurrently, the Company is planning to execute on the 24v line installation options mentioned above.

Q32. How much is the Company forecasting to invest in the IAC program during the bridge period of January 2021 through October 2022, and in the projected test year ending October 31, 2023?

A32. The Company is forecasting to invest $6.7 million in capital expenditures in the projected bridge period January 1, 2021 through October 31, 2022, and $3.3 million in the projected test year extending from November 1, 2022 to October 31, 2023. The planned investment corresponds with a steady installation rate, and commensurate unit purchases to replenish inventories, all in anticipation of continued device installation that will occur during both the bridge and projected test year. Overall, the investment plan supports the continuation of the existing IAC replacement program as approved by the Commission in its Orders for general rate

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cases Nos. U-17767, U-18014, U-18255, U-20162, and U-20561, and for the Company's IRP case No. U-20471. The associated projected capital expenditures are shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 1, columns (c) through (f).

Part III: Programmable Controllable Thermostat (PCT) Program

Q33. Could you please describe the PCT Program?

A33. The PCT program, marketed under the name SmartCurrents™, is a form of demand response known as Variable Peak Pricing (VPP), in which the price of electricity varies by time-of-day and also includes a critical peak price on days of high demand. The Company is running the PCT program, which is available to residential and commercial customers and requires customers to enroll or be enrolled in the Dynamic Peak Pricing (DPP) tariff D1.8. Under the program, the Company seeks to expand the number of participants on the existing DPP rate. Customers who sign up to participate in the PCT program receive a free Wi-Fi enabled thermostat and agree to take service under the DPP rate. The customer's enrollment allows the Company to send a signal to the Company-provided PCT unit, that has been installed in the customer's home, during a DPP critical peak event. By participating in the program, customers allow the Company to send a remote signal adjust the thermostat set-point by four degrees on critical peak days when the cost per kWh increases to $0.95 between the hours of 3:00 P.M. and 7:00 P.M. The customer still retains the option to override the temperature set point; however, manual overrides of the utility signal could drive the customer's bill higher with increased energy usage during the peak period.

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Q34. Has the Commission been supportive of the implementation of the PCT program?

A34. Yes. In its Order dated January 31, 2017 in the Company's rate case No. U-18014, the MPSC authorized capital expenditures to begin a pilot that would utilize a PCT combined with the DPP rate. The initial goal of the pilot was to enroll 10,000 customers over the course of multiple years. In the Company's subsequent rate cases, the Commission denied additional funding, stating that a showing of initial success would be required (Commission's Order in Case No. U-18255), and that it would not consider further expenditure until DTE Electric completes enrollment of the first 10,000 customers and demonstrates some measure of success with the program (Commission's Order in Case No. U-20162). As the Company continued the development of the PCT pilot demonstrating progressive measures of success, it also requested further support for investing in the pilot in the subsequent regulatory proceedings. The Commission in its final Order on April 15, 2020 in the Company's IRP case No. U-20471 supported the continued implementation of the PCT pilot and approved the capital expenditure investment for the tri-annual period extending from 2020 through 2022. Later on, the Commission in its Order on May 8, 2020 in the Company's general rate case No. U-20561 indicated no objection to the Company's request for funding to support the implementation of the PCT pilot to the level of enrollment that was requested in this latest approved general rate case. More recently, in its Order on February 18, 2021 in Case No. U-20793, the Commission approved the settlement agreement among the parties that affirms that the Company's reconciliation of 2019 DR program costs are reasonable, prudent, and in the public interest. Those costs subject to the DR 2019 reconciliation case

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included expenditures incurred in the continuous development and advancement of the PCT pilot.

Q35. Has the Company transitioned the PCT pilot into a DR program?

A35. Yes. The Company decided to transition the PCT pilot into an established DR program in 2021. First, the PCT pilot achieved increased customer interest and engagement, and the Company identified increasing levels of customer enrollment after the refined pilot marketing strategy and customer education efforts were fully operational. Second, from a customer experience perspective, the pilot, now program, also provides customers with an alternative time-of-use option, as well as tools to manage their energy costs. Customer feedback has also been positive as well as program attrition being low – the attrition rate of the PCT pilot is 9.8% as of October 31, 2021. Third, the Company assessed the pilot's potential contribution to peak demand reduction and qualification as an LMR.

Q36. Can the DPP rate and the associated load reduction through DPP events be used as an LMR to meet MISO resource adequacy requirements?

A36. Yes, in response to recent rate language modifications. To qualify as an LMR in MISO, the notification window for an event must be no more than 12 hours. The original event notification window for a DPP event was 6 P.M. on the day before an event was to occur. Since the DPP events start at 3 P.M. and last until 7 P.M., this made the minimum notification window 21 hours, which was initially too long to qualify as an LMR. In the Company's most recent IRP (Case No. U-20471), MPSC Staff's Witness David Isakson recommended reducing the notification window to allow the qualification of DPP (including PCT) as an LMR. The

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Company followed this recommendation and made an ex-parte filing (Case No. U-20923) on November 4th, 2020 to update the tariff language to read "up to 24 hours before, but no less than 6 hours." This language and reduced notification window allows the Company to take capacity credit for MWs reduced during DPP event hours to meet MISO resource adequacy requirements. The Commission approved the updated language in its Order on February 4, 2021. This change affects any customer taking service under rate schedule D1.8, regardless of their SmartCurrents enrollment status.

Q37. Does the Company plan to use the load reduction from the DPP rate (including that of PCT customers) to meet future MISO resource adequacy requirements?

A37. Yes. First, the Company educated customers throughout 2021 and notified them of the change regarding the notification window. The Company plans to take capacity credit for the reduced MW to meet 2022/2023 MISO resource adequacy requirements. The capacity credit will be taken for peak demand reduction resulting from both the DPP rate only load reduction and the load reduction from customers participating in the SmartCurrents™ program.

Q38. How many customers are enrolled on the PCT Program?

A38. As of October 31, 2021, the Company has enrolled 17,691 customers on the PCT program. It is projected, that this will equate to approximately 10 MWs of future capacity avoidance in the near term. 3,269 customers were removed from the PCT Program on August 28, 2021 due to inactivity status or ineligibility which included premise move-outs and rate changes.

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Q39. What steps has the Company been undertaking to gain insights and further develop the PCT program since the Company's prior general rate case No. U-20561?

A39. At the end of 2020, there was a total of 16,137 customers enrolled in the pilot, exceeding the 2020 year-end goal of 15,000 enrolled customers. Much of the continued pilot success can be attributed to the implementation of enhanced marketing and targeting strategies that resulted in increased interest and customer engagement. In 2019, after analyzing multiple data points, such as enrollment data, website performance and customer personas (generic customer segmentation groups), the Company developed and executed new customer targeting and messaging strategies that were carefully developed and tested through a series of A/B experiments with messages tailored to each customer persona. A/B testing consists of sending one variation of a campaign to a subset of your target audience and a different variation to another subset, with the goal of identifying the top performing variant based on email metrics and enrollment results. For example, the persona identified as "Tech Free Let Me Be", is perceived to be less technologically informed based on their DTE interaction history and program participation; this persona was targeted with a message focused on professional installation assistance in an A/B experiment against the standard SmartCurrents email. The installation-focused variant outperformed the standard SmartCurrents email across each measurement of the experiment. Based on this performance, the variant has now been implemented as an ongoing tactic for this persona, and the exercise of performing of A/B email experiments has become a standard ongoing practice for PCT. Additionally in 2019, the Company expanded marketing plans to new

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outreach channels (i.e., welcoming emails) targeting and accessing customers sooner in the customer journey. In 2020, when the stay-at-home order went into effect, DTE paused recruitment activities following the expressed concern of customers' ability to save on the DPP rate. In addition, the Company made a commitment to its customers taking service under rate D1.8 (including PCT customers) to pause calling any DPP events while the stay-at-home order was in effect. During this pause, the Company focused on educating current customers on the time-of-use component of the DPP rate and providing them with saving tips to combat high bills. This increased focus resulted from learnings from focus groups, in which the Company identified that ongoing education of programs that have a rate element can increase satisfaction and participant referrals. The focus groups revealed a strong desire among participating and potential customers to understand how much they have saved on the rate or their potential savings on the rate. This led to the development of the SmartCurrents Bill Comparison Communication that launched in June 2021 to both potential and existing participants. The feedback from the focus groups also lead to the Company designing "Everyday Rate Education Experiments." These experiments will prompt the customer to "set a schedule" on their provided thermostat as well as offer in-the-moment reminders of ways customers can shift their energy use to save during off-peak periods. These prompts will be delivered through text messaging and in-home educational material and executed throughout 2021.

Q40. What are the planned efforts to manage the PCT program going forward?

A40. The Company has been and remains committed to increasing the customer enrollment levels throughout the bridge period from January 2021 through October

2022, and the projected test year from November 2022 through October 2023. The continuous implementation of the PCT program includes the continued recruiting of new customers for continued expansion of the program. The Company is currently researching whether or not to offer a different thermostat brand through SmartCurrents™ and if doing so would further the appeal of the program. The Company is forecasting to reach an enrollment level of 19,000 customers by the end of 2021, 23,000 customers by the end of the bridge period on October 31, 2022, and 25,000 customers by the end of the projected test year on October 31, 2023. The enrollment progress and projection are shown in Table 4.

Table 4 Historic and Projected PCT Enrollments

	Historical 12 Mo. Ended 12/31/2020	Projected 12 Mo. Ending 12/31/2021	Projected 8 Mo. Ending 10/31/2022	Projected 12 Mo. Ending 10/31/2023
Ending Balance	16,137	19,000	23,000	25,000

Q41. How much is the Company forecasting to spend in the PCT program going forward during the bridge period of January 1, 2021 through October 31, 2022, and in the projected test year ending on October 31, 2023?

A41. The Company is forecasting to invest $8.2 million in capital expenditures during the bridge period of January 1, 2021 through October 31, 2022, and $3.5 million in capital expenditures during the projected test-year period of November 1, 2022 through October 31, 2023. This level of spend is necessary to reach the customer enrollment level of 23,000 by the end of the bridge period and of 25,000 by the end of the projected test-year period and includes thermostats, installation and technical support, program implementer support and other outside services. The associated projected capital expenditures are shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 2, columns (c) through (f). In addition, the Company is planning to spend $0.5 million in O&M to manage and operate the platform that serves as interface with customers and is used to call events and monitor performance. The associated O&M expenses are included in Company Witness Burns' Exhibit A-13 Schedule C-5.9, line 9.

Part IV: Bring-Your-Own Device (BYOD) Program

Q42. What is the BYOD program?

A42. The BYOD program, marketed under the name Smart Savers, is a program available to residential and commercial customers who already have an installed Wi-Fi enabled smart thermostat. The Company incentivizes customers to enroll in the program. Once enrolled, customers' thermostats are configured to allow the Company to send a control signal during Smart Savers events, which raises the thermostat's set-point by up to four degrees during the event. Events only occur Monday through Friday between the hours of 12:00 PM and 8:00 PM and are limited to 14 events per year. As a result of this change in thermostat configuration at the customer sites, the Company is able to account for demand reduction at peak times during the called event. Smart Savers customers are always notified prior to an event. In some instances, the Company will precool a participant's home to increase the energy savings recognized during the event. The customers can override the event or opt-out completely if they choose to do so. No financial penalties or incentive reductions are associated with the customers' override actions.

Q43. How many customers are enrolled in BYOD or Smart Savers Program?

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A43. There were 34,764 devices enrolled in the Smart Savers Program as of October 31, 2021. The Company is currently claiming 55 MWs of available capacity for the program in 2021 as shown previously in Table 1.

Q44. What are the Company's planned efforts for the BYOD program going forward?

A44. Based on the previously mentioned results regarding customer engagement through enrollment and event participation as well as peak demand reduction levels, the Company plans to continue marketing and operating the program. The Company continues to monitor customer behavior during the events and evaluate if additional measures or incentives are necessary to continue customer engagement. The Company may initiate appropriate modifications based on program results. The Company began registering the BYOD program as an LMR to meet MISO resource adequacy requirements in 2020/2021 and continued to do so in the 2021/2022 Plan Year. The Company plans to invest in the ongoing enrollment and integration of the new enrollees with an interim goal of 35,000 by the end of 2021 and 50,000 by the end of the test year period, and in the execution and evaluation of BYOD events throughout the bridge period and the projected test year, which ends on October 31, 2023. Table 4 below shows historic and projected enrollment levels for the program:

Table 5 Historic and Projected BYOD Enrollments

Period	Historical 12 Mo. Ended 12/31/2020	Projected 12 Mo. Ending 12/31/2021	Projected 8 Mo. Ending 10/31/2022	Projected 12 Mo. As of 10/31/2023
Ending Balance	28,042	35,000	41,000	50,000

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Q45. Has the Commission been supportive of the Company's BYOD program?

A45. Yes. In its interim order in the Company's IRP case U-20471, issued on February 20, 2020, the Commission was supportive of the BYOD then-pilot. Since the Company was then directed to refile the DR forecasted capital expenditures including costs for the BYOD pilot, the Company chose to remove all the capital associated with "Other DR Pilots", including that of the BYOD pilot, in its compliance filing on March 20, 2020. Later, in the 2019 DR Reconciliation case U-20793, the Company effectively included and updated the capital expenditures for the approved BYOD program. In its Order on February 18, 2021, the Commission approved the settlement agreement among the parties resulting from the Company's 2019 DR Reconciliation case No. U-20793 that included the requested investment for the BYOD program. As further reaffirmative support, following the Administrative Law Judge (ALJ)'s recommendation, the Commission approved the capital expenditure request for the BYOD pilot, now program, in its Order on May 8, 2020 in the Company's 2019 general rate case No. U-20561.

Q46. How much is the Company forecasting to spend in the BYOD program going forward?

A46. The Company is forecasting to spend $1.8 million in O&M expenses on an annual basis in the BYOD program. This level of O&M spend is necessary to reach the estimated enrollment level of 41,000 by the end of the bridge period and a future goal of 50,000 by the end of the projected test-year period. The associated projected

O&M expenses are shown in Company's Witness Burns' Exhibit A-13, Schedule C5.9, line 9, column (i) and corresponding note 4.

Q47. Does the Company estimate an increase in O&M spend in the BYOD program?

A47. Yes. The majority of the spend is necessary to conduct the operations and management efforts for the marketing, enrollment, integration, and evaluation of the annual target of BYOD customers and corresponding devices. For the use of a demand response management system, the Company engaged in a specific contract with EnergyHub, which is a nationally recognized industry leader in management solutions with a focus on utility-driven programs. As indicated previously, the O&M expenses are allocated to support the use of this external platform to integrate customers and manage performance for the applicable DR programs on a looking forward basis. As this external platform solution is now provided and operated using Cloud technology, it is considered a software-as-a-service procurement, and thus O&M expense.

Part V: Other Demand Response Programs and Pilots

Q48. What DR pilots is the Company investing in?

A48. The Company is developing or planning DR pilots as part of the ongoing evaluation of its DR portfolio. First, the Company is currently implementing the Plug-in Electric Vehicle (PEV or EV) pilot in partnership with the EPRI's Transportation Program. This pilot is known as the DTE Smart Charge pilot. Second, the Company is launching, marketing, and implementing the Peak Time Savings (PTS) pilot (formerly known as Peak Time Rebates (PTR) in prior filings) for residential customers. Third, the Company is working on the implementation plans of a battery energy storage pilot for or in conjunction with Commercial and Industrial customers within the DR space. Fourth, the Company is evaluating the development of two additional pilots through a Request for Information (RFI) with potential impact on peak demand reduction: a residential generator pilot and an interruptible window air conditioner pilot. Last, the Company's DR organization is supporting the development of Non-Wire Alternatives (NWA) pilots that are being developed under the leadership of the Distribution Operations (DO) organization and sponsored in this proceeding by Company's Witness Pfeuffer.

In addition to the aforementioned pilots, the Company is evaluating the improvement of two additional programs. The first is the replacement of LCDs in the interruptible water heating program. The second is an enhancement for current C&I interruptible customers and consists of a dashboard or platform that would be provided to C&I customers already on an interruptible rate to help improve event performance.

Q49. What is the Company's overall approach to develop and manage the ongoing and future DR pilots?

A49. As described at the beginning of my testimony, the Company designs and executes DR programs to help customers reduce their peak energy use, which provides value to the participating customers, in the form of savings or other compensation, to the utility through reduced capacity needs and lower capacity costs, and all customers through reduced overall system costs. The Company has several successful, long-term programs which support its peak-reduction objectives, and many other pilot efforts through which the Company explores diverse opportunities to engage customers and reduce peak load. However, our DR offerings and customer engagement should not remain static over time, and the continued development of pilots is critical to ensure a pipeline of learnings to support future programs and to present customers with the best program offerings. To support ongoing pilot efforts, the Company needs to remain agile enough to efficiently redeploy DR pilot spending and resources as capacity needs change, customer behaviors evolve, program acceptance is assessed, or other more cost-effective technologies and opportunities arise in the near future. This flexibility will ensure DTE Electric is well positioned to expand existing or future programs to respond to changing market conditions and customer behavior. The Company continues to evaluate alternative programs that may emerge as a result of insights from pilots or utility benchmarking efforts. In the coming years, the Company expects to continue developing new pilots and programs that may become economic alternatives to capacity and have an appropriate level of customer adoption potential.

Q50. What is the EV or DTE Smart Charge pilot?

A50. The Company is conducting a pilot that involves a partnership with the EPRI Transportation Program. The pilot leverages EPRI's PEV platform to streamline the management of PEV charging. The Company is partnering with specific PEV automotive manufacturers in its service territory to assess the effectiveness of the Open Vehicle Grid Integrated Platform (OVGIP) concept to integrate PEV charging with grid objectives through demand response. The Company and the automotive manufacturers (OEMs) seek a better understanding of the responsiveness of the PEV owners and their willingness to participate in DR events specifically targeted at vehicle charging and the amount of demand that is curtailed

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through events. As previously mentioned, this pilot was pre-approved for capital cost recovery in the Company's last IRP.

Q51. What are the EV pilot's main objectives?

A51. The Company is focusing on the main pilot objectives as the pilot expands to a larger population:

- Evaluate energy reduction (kWh) and demand reduction (kW),
- Evaluate results from different times, lengths, and participation levels of events,
- Assess EV user behavior in response to different incentive mechanisms such as up front and program-end incentives,
- Assess override (Opt-in / Opt-out) approach by EV users, and
- Test deliverability of events, for instance, ensuring communication signals functioned properly.

Q52. What are the customer benefits of participating in the EV pilot?

A52. In addition to receiving an incentive from the Company for their participation, customers will be given a unique way to manage their EV charging. Pilot customers will also be able to share feedback to the Company and OEMs on charging habits and shape the future of EV charging as a DR resource. In addition, participating customers will learn about the concepts of demand response as well as reverse demand response.

Q53. What is the estimated impact of the EV pilot for the pilot duration?

A53. The Company is working with the OEMs to evaluate the performance of 2021 events. In 2019, the Company called twelve (12) events in a 6-month timeframe.

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The Company and OEMs identified a total demand response reduction of 702.1 kWh across all 12 events. The average participation from PEVs across all of the events was 24% full participation and 76% partial or non-participation, which overall provided an initial assessment of the customer override behavior (Opt-in/Opt-out). These events consisted of 165 customers who were employees of the OEMs and were designed to ensure any issues (i.e. communication or signal issues) could be solved prior to an expansion of a larger pool of customers.

Q54. Could you expand on the implementation plan for the EV Pilot?

A54. Yes. The continuation of the pilot initially scheduled for 2020 didn't resume until 2021 due to delays experienced by the OEMs. In April 2021, the Company began recruitment of all eligible electric vehicle owners who drive a partnered OEM vehicle within DTE Electric's service territory with a goal to enroll up to an estimate of 1,000 participants. As of October 31, 2021, the pilot has 347 participants. The first DR event occurred on May 19, 2021, and the Company estimates that there will be at least 30 DR events called throughout calendar year 2021. This stage of the pilot development and testing extended through December 2021. Based on the verified results (i.e., peak load reduction), the Company and partnered OEMs will assess the opportunity to expand the pilot into a more fully developed, larger-scale public program in the future.

Q55. How will the EV pilot be evaluated?

A55. In addition to working with the OEMs to measure the load reduction during events, the Company and OEMs will monitor customer engagement in the acquisition phase based on available marketing metrics. The Company and OEMs plan to

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conduct consumer research to assess customers' overall experience and likelihood to recommend, satisfaction ratings and motivational factors. Additionally, the Company and OEMs have agreed to call reserve DR events to measure the how customers respond to being asked to start charging their vehicle and specified times.

Q56. How much is the Company forecasting to invest in the EV pilot?

A56. The Company is forecasting to invest $0.78 million in capital expenditures during the bridge period and $0.35 million during the forecasted test year. These amounts are included in the Other Demand Response Programs and Pilots funding shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, column (c) through (f).

Q57. What is the Peak Time Savings (PTS) pilot that the Company is investing in?

A57. The PTS pilot, formerly known as Peak Time Rebates, is structured to reward customers for reducing energy consumption during the Company's called Peak Time Events. The participating customers will receive bill credits for each event based on measured reductions in customers' energy demand relative to a pre-established baseline, which has been initially developed based on features of comparable utility programs. Unlike the Company's current DPP rate, the PTS pilot does not increase a customer's electric rate during peak events, but instead provides customers with a no-risk introduction to demand response.

Q58. What are the main objectives of the proposed PTS pilot?

A58. The main objectives of the PTS pilot are as follows:

- Analyze outcomes to determine potential peak-savings impacts and the impact on rates and revenues.

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- Assess customer receptiveness and the value customers receive from PTS; and
- Identify and process new learnings that could be applied to current and future demand response offerings.

Q59. What are the customer benefits of participating in the PTS pilot?

A59. The PTS pilot provides customers with a tool to become familiarized with the concepts of peak demand and demand response in a "no regrets" environment. Through the PTS pilot, customers will be able to gain a greater understanding of energy usage and its impact on their electric bills and how to save. Because of the no-risk design, customers who are uncomfortable with the design of other demand response programs may be drawn to this pilot. Based on benchmark findings, the no-penalty design of the PTS pilot should broaden the program reach amongst the DTE Electric customer base, influence high participation and retention rates, and increase customer satisfaction. Participating customers who reduce their energy consumption during the called events will also benefit from reduced energy bills through bill credits.

Q60. What is the estimated impact of Peak Time Events for the pilot duration?

A60. The Company currently estimates that the impact of the pilot would be approximately three (3) megawatts (MW) of peak demand reduction, and savings in energy consumption ranging anywhere from 155 to 260 megawatt hours (MWh) over the course of the pilot.

Q61. Could you expand on the implementation plan of the PTS pilot?

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A61. Yes. The Company launched the PTS pilot as recruitment started in Summer 2021 with the first invitations sent in June 2021, coinciding with the first summer event season. Throughout the complete customer acquisition phase, the PTS pilot is expected to be offered to approximately 450,000 residential electric customers who will “opt-in” to the pilot, with the goal of obtaining 10,800 eligible participants, based on performance of other DTE pilots. As of October 31, 2021, the PTS has 8,919 customers enrolled in the pilot, 36% of which are considered low-income. The PTS pilot is designed to test different variable sets during its two phases to inform the design of a potential full-scale program. First, during the customer acquisition phase, which is expected to conclude on December 31, 2021, the pilot is testing three sets of marketing and outreach variables (i.e., three rebate levels, two benefit messages, and various outreach channels) to determine which combinations result in the highest opt-in rates. Then, during the event phase, the pilot will test the responsiveness of different customer groups (i.e., high technical potential, low-income, and mixed potential / mixed income) to different rebate levels. Peak Time Events will be called on weekdays from 3 p.m. to 7 p.m., excluding holidays, during all four seasons of the year with a maximum of 14 occurrences (or 56 hours) in a calendar year. Customers will be notified of events via email and/or text by 6 p.m. the day prior, as well as receive reminders prior to the start and end of each event. Following each event, the Company will assess the impact on peak savings by comparing the customers’ actual electricity usage during an event to a pre-determined baseline calculated based on a set of the highest non-holiday weekday usage in prior periods. Participating customers are expected to receive a bill credit to the extent that a reduced home energy usage is verified during the peak demand event announced by the Company. The pilot has developed

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comprehensive webpages in order for the Company to provide customers with an overview of the program and answer common questions, automatically process enrollments completed via self-service, collect customer event notification preferences, and provide an educational connection point for pilot participants, for instance when they need savings tips to reduce usage during events or when they'd like to review their individual event performance. Additionally, the pilot offers a dedicated team of customer service advisors specifically trained to answers all PTS questions and complete enrollment or unenrollment on behalf of the customer. As indicated above, the recruiting phase started in Summer 2021, and the Company has and will continue to invest in the execution of the pilot throughout the development, launch, recruitment, and event phases in 2021 and 2022. The first event season began in Summer 2021 with the first Peak Time Event called on August 25, 2021, with 2,235 customers enrolled at the time of the event. Overall, the pilot is tentatively scheduled to conclude at the end of Summer 2022. At that time, the pilot will be fully evaluated to determine the next steps, which could include, but are not limited to, continuing the pilot, continuing the pilot with modifications, or discontinuing the pilot. Participants will be notified of any outcomes.

Q62. How will the PTS pilot be evaluated?

A62. To evaluate the viability of PTS as a full-scale program, the Company will assess peak demand reduction and overall energy use impacts and will monitor customer engagement in the acquisition phase based on available marketing metrics. Additionally, the Company plans to conduct consumer research to assess customers' overall experience and likelihood to recommend, satisfaction ratings and motivational factors.

Q63. How much is the Company forecasting to invest in the PTS pilot?

A63. The Company is forecasting to invest a total of $1.7 million in capital expenditures over the bridge period and the forecasted test year and is included in Other Demand Response Programs and Pilots shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, columns (c) through (f). In addition, the Company is planning to spend $0.25 million in O&M expenses to support the pilot and complement the implementation activities. The associated projected O&M expenses are included in Demonstrating and Selling Expenses – DR in Company's Witness Burns' Exhibit A-13, Schedule C5.9, line 9.

Q64. Could you describe the battery energy storage pilot with C&I customers that the Company is planning to invest?

A64. Yes. The battery energy storage pilot will be a behind-the-meter (BTM) lithium-ion battery energy storage system (BESS) at customers' sites. It is designed to test the ability to achieve peak demand shaving or shifting during demand response events. As part of the implementation plan, the Company is looking to partner with one or two C&I customers.

Q65. What are the main objectives of the BTM battery energy storage pilot?

A65. The main objectives of the designed pilot are as follows:

- Evaluate the effectiveness of the BESS to achieve system peak demand reduction when a demand response event is called by the Company.

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- Assess customer's actions to achieve demand charge and overall bill reduction.
- Gain operational experience on battery installation, management, and control interfaces when the system is located in a customer's site as opposed to a Company's site.
- Engage with customers to better understand their interest in hosting and potentially escalate BESS.
- Assess feasibility for sharing asset control between customer and the Company; and
- Facilitate the understanding of multiple energy storage values, compensation models, and the integration of battery storage in wholesale markets to support tariff development as contemplated by the Commission's order in MPSC Case No. U-21032.

Q66. What are the customer benefits of participating in the BTM battery energy storage pilot?

A66. The pilot will target customers who are already enrolled on the Company's Rate D4, Rate D6.2 or Rate D11 electric tariffs (excluding sites or load under Rider 10) since those customers are more suited for a pilot participation due to their peak load profiles, outdoor space availability and operational capabilities. The Company will retain the ability to control the BESS when calling a dispatch event while the customer will retain the option to use the BESS when the Company does not call an event. The dispatch strategy will consider the ability for the Company to call a certain number of scheduled DR events with a prior-day notification, and a very limited number of emergency DR events with immediate notification. When no Company DR event is planned, the customer will be able to dispatch the BESS to address its facility energy needs on a day by day basis. It is expected that more detailed commercial arrangements will balance the different control and use possibilities split between the Company and the customer. This arrangement will allow for the customer to get experience operating a battery while potentially reducing peak operating costs.

Q67. What are the estimated impacts of the BTM battery energy storage pilot?

A67. While the design parameters are subject to change as the Company moves forward with the pilot engaging the customer host, the battery will likely be up to 500 kW/2 MWh at each of potentially two sites to reduce peak customer and system demand over an event of up to 4 hours. In the recently finalized Request for Information (RFI), the technical parameters of the proposals ranged between 250kW/4 hours and 500kW/8 hours, providing the Company with a better assessment of the potential equipment availability, and with flexibility to design alternative implementation plans that can better match the variable customers' sites.

Q68. Could you expand on the implementation plan for the BTM battery energy storage pilot?

A68. Yes. The Company completed the RFI in March 2021. The results of the RFI highlighted aspects that need to be considered during the equipment acquisition and installation stages and were reflected in the subsequent Request for Proposal (RFP). The Company has conducted the RFP with additions of detailed requests for adherence to strict fire safety standards, equipment delivery time, and updated costs for more specific pilot siting or siting's within the Company's service territory. The Company is in the process of finalizing its selection of a specific equipment provider based on information gathered from the RFP. Once a vendor is officially selected and contracted, the Company will initiate the marketing and outreach activities to engage and contract with the pilot host customer and/or customers that can better fit the characteristics of the intended configuration and proposal resulting from the RFP. The pilot development and installation are forecasted to extend throughout 2021 and 2022, with a current estimated installation in 2023, depending on the selected proposal resulting from the RFP, the potential need of equipment testing for safety and configuration with DTE Electric's systems, and on the commercial arrangement with the host customer.

Q69. How will the BTM battery energy storage pilot be evaluated?

A69. The BTM battery energy storage pilot will be evaluated by measuring the load reduction during events called by the Company against the battery expected parameters as well as the evaluation of other system impacts. The customer peak load reduction will also be evaluated to observe the peak bill reduction on the customer's bill for both Company called events and customer's use. The Company will also look to evaluate communication and sharing of the battery controls with a customer.

Q70. How much is the Company forecasting to invest in the BTM battery energy storage pilot?

A70. The Company is forecasting to invest $2.8 million in capital expenditures for a planned two site-project of 1,000 kW / 4 MWh total. A limited capital investment amount of the total projection has been allocated for the respective bridge period and projected test-year period of this general rate case, and is included in the Other

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DR Programs and Pilots funding shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, column (c) through (f).

Q71. Will this battery storage pilot facilitate the understanding of multiple energy storage values, compensation models, and the integration of battery storage in wholesale markets to support tariff development as contemplated by the Commission's order in U-21032?

A71. Yes. The Commission's August 11, 2021, Order in Case No. U-21032 encourages utilities to propose, in upcoming rate cases, "well-designed retail tariffs that account for the full value stack ESRs offer, while also allowing for participation through the utility in regional wholesale markets" (Order at p. 27). The order contemplates utilities participating in wholesale electricity markets on behalf of customer-owned energy storage resources. In order to develop such tariffs and related pilot programs for customer-owned battery storage, the Company needs to gain experience with the application of storage technology by end use customers and interactions with the wholesale market. The proposed energy storage pilot will provide data and other learnings on the services and values battery storage can provide to end use customers and the utility and how storage can be paired with complementary programs such as demand response to maximize value and optimize operation of energy storage. The energy storage applications in this pilot will serve an energy management function for the participating customers to help reduce electricity bills while also providing services when needed by the utility to support reliability in the bulk power system. Quantifying how the storage is used, the associated values it brings to the customer and the Company, direct and indirect costs, and coordination between the customer and the Company will help the Company develop appropriate

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tariffs and compensation models as contemplated by the Commission.The Company expects to engage further with the Commission and stakeholders to develop such tariffs using data from the pilot.

Q72. Could you describe the residential generator pilot that the Company plans to invest in?

A72. Yes. The Company plans to conduct a residential customer-owned natural gas generator pilot. The pilot will leverage a third-party service provider's platform utilizing telemetry to shift customers' electric load to the customers' generator in real-time during peak events. Initial plans indicate that the customers will receive an incentive for their participation in the program.

Q73. What are the general objectives in pursuing a residential generator pilot?

A73. The main objectives of the residential generator pilot are as follows:

- Assess the viability of a program that can act as a year-round DR asset responding on short-term notices for peak events
- Determine whether customers would be willing to participate actively and allow for real-time telemetry to control their generators during an event
- Measure how effective the customer-owned generators respond as a year-round LMR
- Assess customer receptiveness and the value customers receive from a residential generator pilot; and
- Identify and process new learnings that could be applied to current and future demand response offerings.

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Q74. What are the customer benefits of participating in the residential generator pilot?

A74. Pilot participants will benefit by receiving an incentive from the Company as well reduced electric bills during peak events.

Q75. What is the estimated impact of the residential generator pilot for the pilot duration?

A75. Through early analysis, it is estimated that there are at least 60,000 residential generators with an estimated impact of 5kW of load reduction per unit. The Company is plans to issue a Request for Information (RFI) to better understand the opportunities for a demand response pilot that exist within the Company's service territory.

Q76. Could you expand on the implementation plan of the residential generator pilot?

A76. Yes. The Company is working on a progress plan that includes the engagement with the third-party supplier of the platform and customer interface at the conclusion of the RFI, and subsequently, engagement of specific customers in 2022.

Q77. How will the residential generator pilot be evaluated?

A77. The Company considers that the following metrics will be in place and tracked to evaluate pilot effectiveness: customer acquisition and enrollment rates (including attrition), marketing metrics (outreach activities and their impact), and load shed during different type of events.

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Q78. How much is the Company forecasting to invest in the residential generator pilot during the bridge period of January 2021 through October 2022, in the projected test year ending October 31, 2023?

A78. The Company plans to invest $0.46 million in capital through the bridge period and projected test year and is included in the Other DR Programs and Pilot funding shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, columns (c) through (f).

Q79. Could you elaborate on the plans to develop a residential window air conditioning pilot?

A79. Yes. The Company plans to conduct a residential customer-owned window air conditioning pilot. The pilot will leverage a third-party service provider's demand response platform to interface with devices to cycle and/or offset the temperature during peak events and evaluate performance. Initial plans indicate that the customers will receive an incentive for their enrollment and participation in the pilot. Additionally, the Company is exploring options to provide customers with a company-owned hardware solution to transform any window air conditioning unit to a Wi-Fi-enabled demand response resource to broaden the eligible audience.

Q80. What are the general objectives in pursuing a residential window air conditioning pilot?

A80. The overall objective of a residential window air conditioning pilot is to assess the viability of a program that can act as a summer DR asset responding on short-term or long-term notices of peak events. In addition, other objectives include:

- understanding customer receptiveness to the pilot concept, different incentive offers, and varying event methodologies,
- evaluating overall energy reduction (kWh) and demand reduction (kW),
- evaluating peak event results from different methodologies, times, lengths, and participation levels,
- identifying and processing new learnings that could be applied to current and future demand response offerings.

Q81. What are the customer benefits of participating in the residential window air conditioning pilot?

A81. Pilot participants will benefit by receiving an incentive from the Company as well reduced electric bills during peak events.

Q82. What is the estimated impact of a residential window air conditioning pilot duration?

A82. Through early analysis, it is estimated that are approximately 25% of households have a window A/C unit within the Company's service territory. The Company is plans to issue a RFI to better understand the opportunities for a demand response pilot and the load reduction capabilities that exist within the Company's service territory.

Q83. Could you expand on the implementation plan of the residential window air conditioning pilot?

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A83. The Company is working on a project plan that includes the engagement with a third-party supplier of the platform and customer interface, and subsequently, engagement of eligible customers in 2022.

Q84. How will the residential window air conditioning pilot be evaluated?

A84. The Company considers that the following metrics will be in place and tracked to evaluate pilot effectiveness: customer acquisition and enrollment rates (including attrition), marketing metrics (outreach activities and their impact), and load shed during different type of events.

Q85. How much is the Company forecasting to invest in the residential window air conditioning pilot during the bridge period of January 2021 through October 2022, in the projected test year ending October 31, 2023?

A85. The Company plans to invest \$0.7 million in capital through the projected test year and is included in the Other DR Programs and Pilot funding shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, columns (c) through (f).

Q86. Could you elaborate on the plans to replace water heating control units?

A86. Yes. The Company plans to begin the replacement of approximately 48,000 residential and commercial water heating load control units for customers who currently take service under the water heating service rate or D5 in 2023. By taking service under this separately metered rate, customers' water heating units can be interrupted remotely by the Company in exchange for a discounted energy charge for the associated usage. Similar to the reasons behind the IAC replacement project, the Company has identified that the original LCD units that currently reside in customers' homes have reached the end of life and no longer function as intended. The pilot will also study the feasibility of recruiting new customers onto the interruptible water heating rate.

Q87. What are the general objectives in replacing the water heating control units?

A87. By investing in a water heating control unit replacement program, the Company is able to extend the equipment life as well as increase the available capacity in MISO. This program also provides an additional demand response program option for residential and commercial customers.

Q88. How much is the Company forecasting to invest in the Interruptible Water Heating program during the bridge period of January 2021 through October 2022, in the projected test year ending October 31, 2023?

A88. The Company plans to begin the project in early 2023 and is forecasting to spend $0.15 million in capital through the projected test year and is included in the Other DR Programs and Pilot funding shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, columns (c) through (f).

Q89. What is the Commercial and Industrial (C&I) Dashboard Technology that the Company would like to provide interruptible customers?

A89. The Company is planning to partner with a program implementer to provide C&I customers who take service under a demand response tariff (i.e. D8, R10 and R12) with technology and software so customers can better understand and sequentially, improve upon their event performance. In addition, the technology can provide

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more advanced analytics for better DR forecasting for the Company to provide to MISO.

Q90. How can the C&I Dashboard Technology assist customers during interruptible events?

A90. The technology provides real time telemetry to the customer and the Company, so the event performance is monitored in real time and displayed on a dashboard for the participating customer and the Company. This instantaneous feedback lets both the customer and the Company know if additional actions need to be taken to reduce load to committed levels. In addition, the technology provides more advanced analytics for better DR forecasting and post-event analysis.

Q91. How much is the Company forecasting to invest in the C&I Dashboard Technology during the bridge period of January 2021 through October 2022, in the projected test year ending October 31, 2023?

A91. The Company is forecasting to spend $0.35 million in capital through the projected test year to secure a contract with a third party to secure and provide the appropriate technology. This spend is included in the Other Dr Programs and Pilot funding shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, columns (c) through (f).

Q92. In summary, what is the Company's forecasted capital expenditure and the respective funding request for the other DR Programs and pilots?

A92. The Company is forecasting to invest $5.0 million in capital expenditures during the bridge period of January 1, 2021 through October 31, 2022, and $2.8 million in capital expenditures during the projected test year from November 1, 2022 to

October 31, 2023. This level of spend is necessary to continue developing the EV pilot, PTS pilot, storage pilot, the newly initiated evaluation of the residential generator and window air conditioner pilots as well as the water heating replacement project and C&I Dashboard Technology. The associated projected capital expenditures for Other DR Programs and Pilots are shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, column (c) through (f).

Part VII: Demand Response Customer Penalty Revenues

Q93. What is the current penalty for non-interruption penalty of interruptible customers?

A93. The current non-interruption penalty is $50 per kW applied to the highest 60-minute integrated interruptible demand created during the interruption period.

Q94. What is the Company proposing for the future non-interruption penalty of interruptible customers?

A94. The Company is proposing for the non-interruption penalty to be the higher of $50 per kW applied to the highest 60-minute integrated interruptible demand created during the interruption period or the actual damages incurred by the Company, including MISO penalties.

Q95. Why is the Company proposing this change?

A95. The Company is proposing this change to ensure non-performing interruptible customers are not subsidized by other PSCR customers. Under the current $50 kW penalty, the possibility exists that MISO penalties may exceed the penalties paid by

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the Company's non-interruption customers, resulting in a subsidization of non-interruption customers by other PSCR customers.

Q96. What is the current method to allocate and distribute demand response related penalties from non-performance by customers during DR events?

A96. There is currently not an approved method to distribute penalty revenues. However, under performance penalties in recent events have been allocated to Power Supply Cost Recovery (PSCR) customers as a credit.

Q97. How does the Company propose future allocation of non-performance penalties?

A97. The Company proposes to first offset any MISO allocated penalties that flow through PSCR to ensure PSCR customers are held harmless. Any excess customer penalty revenues above the MISO issued penalties will then be allocated towards improving demand response programs. This may include, but not limited to, items such as IT infrastructure improvements, customer communication improvements, marketing, and enhanced education for DR participating customers. Under the circumstance that demand response program improvement opportunities are not readily available, or if the improvements do not fully utilize the penalty revenues, the Company will distribute penalty revenues to PSCR customers.

Q98. Will the Company seek a financial incentive on the revenues above MISO penalties that are used in DR program improvements?

A98. No. The Company does not plan to seek a financial incentive on the customer penalties revenues. The Company will include an explanation of how the penalty revenues were utilized in its annual demand response reconciliation.

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Q99. Does this complete your direct testimony?

A99. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

NEAL T. FOLEY

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF NEAL T. FOLEY

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Neal T. Foley (he/him/his). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company as Director, Regulatory Affairs.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your education background?

A3. I received a Bachelor of Science in Aerospace Engineering and a Bachelor of Science in Mechanical Engineering from the University of Michigan. I also received a Master of Science in Systems Engineering from Johns Hopkins University and a Master of Business Administration from Georgetown University.

Q4. What work experience do you have?

A4. In 2007 I was employed by Lockheed Martin Corporation as a Satellite Operations Engineer. In 2008, I was hired by Booz Allen Hamilton as an Associate Consultant in its Federal consulting practice. In 2012, I was hired by Deloitte as a Manager of Financial Analysis in its Federal consulting practice. In 2014, I was hired by McKinsey & Company as an Associate Consultant, ultimately being promoted to Engagement Manager before my departure in 2017. In 2017 I was hired by DTE Energy Company as Manager of Corporate Strategy. In this role I was broadly responsible for tracking and assessing utility industry trends, executing analyses to better understand the economic impacts of emerging technologies and business models, and leading strategic initiatives for the Company. I was promoted to my current role as Director of Regulatory Affairs in 2020.

Q5. What are your current duties and responsibilities with DTE Electric?

A5. My responsibilities broadly include the management of regulatory activities relative to DTE Electric's Load Research, Tariffs, Pricing, and Rate Design.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. No. I have not previously sponsored testimony before the MPSC

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<u>Purpose of Testimony</u>

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to describe the Company's overall approach to rate design and the key components of new tariffs and tariff changes that the Company is proposing. As such, my testimony has four major components:

- Rate Design Principles. In this section I describe the Company's overall approach to rate design in order to set proper context for the subsequent sections.
- Time of Use (TOU) Full Implementation. In this section I address the recent history of TOU rates, the preliminary results of the Company's Advanced Customer Pricing Pilot (ACPP), and describe the key components of the Company's proposed Rate Schedule D1.11 (Residential Service Rate – Standard TOU), including providing details of the customer rollout.
- Voluntary residential "Stable Bill Service Level" demand-based tariff. In this section I address the recent history of residential demand rates, discuss the overall motivation and basis for introducing a voluntary demand-based tariff, and describe the structure of the Company's proposed Rate Schedule D1.12 (Residential Service Rate - Stable Bill Service Level)
- Rider 18 (Distributed Generation Program). In this section I address the recent history of Distributed Generation (DG) rate design, introduce new data and analysis the Company has prepared in support of its proposed changes, and describe the structure and key changes of the Company's proposed Rider 18.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. No. I am not sponsoring any exhibits in this proceeding.

Rate Design Principles

Q9. What are the key principles that guide the Company's rate design activities and proposals?

A9. The Company uses three basic principles to guide its rate design activities and proposals. These principles are:

- Cost-alignment. Rate schedules ("rates" or "tariffs") should be cost-aligned, meaning they reflect both *how* and *when* costs are incurred.
- Optionality. Customers should be provided with multiple base rate and voluntary rate options and be free to select the offerings that best fit their needs and preferences.
- Broad adoption. Rates should be made available as widely as possible. Eligibility requirements, including separate metering requirements, should be used sparingly.

I will discuss these principles in greater detail below.

Q10. Besides these three rate design principles, are there any other considerations that guide the Company's thinking when proposing new rates or rate design changes?

A10. While the Company uses the three principles summarized above to guide its thinking as it contemplates new rates or rate design changes, there are other considerations that the Company takes into account as well. More specifically the Company considers the following when contemplating new rates or rate design changes:

- Incrementalism. The Company acknowledges that customers broadly value stability and certainty in the structure of their electric rates. As such, when introducing new rates or changes to existing rates, potential customer impacts should be considered so that sufficient communication and education can be focused on those customers likely to see the largest impact. Incrementalism must be balanced with other considerations, so there is no "one size fits all" answer to how new structures should be introduced. Instead, incrementalism should be considered on a case-by-case basis as new structures are being contemplated.
- Cost of implementation. The Company considers whether the cost of implementing a new rate or rate design change is prudent by weighing those implementation costs against how the new rate or rate design change will better achieve the principles outlined above.

Q11. As it applies to the Company's first principle, what does it mean for a rate to be "cost-aligned"?

A11. To best understand this principle, it is helpful to distinguish between a rate being cost-*based* and being cost-*aligned*. Being cost-*based* means that the rate is designed to recover those costs that have been allocated to the relevant class through an approved Cost of Service (COS) study.

For a rate to be cost-*aligned*, it must also accurately reflect the underlying cost drivers for each category of cost incurred by the Company. These cost drivers include both *how* costs are incurred, and *when* they are incurred. Said differently, the structure of the rate would need to match the structure of the cost causation for it to be cost-*aligned*.

Q12. How are costs typically incurred by the Company?

A12. Broadly, the Company incurs three types of costs:

- Energy-related costs. These costs vary with the volume of energy being delivered by the utility. These costs can also be dependent upon the time of day or season the energy is delivered. The main components of energy-related costs are fuel and purchased power.
- Demand-related costs. These costs vary with the peak demand being placed on an asset or assets. In other words, assets that are sized to meet a peak demand would fall into this category. The main components of demand-related costs are the fixed portions of generation assets and certain types of distribution equipment.
- Customer-related costs. These costs generally vary with the number of customers that the Company serves and are unrelated to the usage characteristics of those customers. Examples of customer-related costs are near-site distribution infrastructure and other delivery costs such as billing resources and infrastructure.

Q13. When are costs typically incurred by the Company?

A13. Costs are incurred at different times by the Company depending on the underlying category of costs. As such, it is helpful to look at each category of cost separately:

- Energy-related costs. These costs are incurred at all times by the Company given that it is delivering energy at all times. Energy costs on a per kWh basis tend to vary over hours, days, and seasons, driven by system usage.
- Demand-related costs. These costs are incurred coincident with the peak that could be placed on the underlying asset. For example, a portion of the Company's generation portfolio is built to meet peak system demand, and these costs are therefore incurred coincident with system peaks. Similarly, certain distribution assets, such as substations and transformers, are built to meet the aggregate peak demand of the customers that the asset serves. These costs are therefore incurred coincident with the aggregate peak demand that could be placed on the underlying asset by those customers.
- Customer-related costs. As outlined above, these costs do not vary with the usage characteristics of customers within a customer class, and therefore cannot be assigned to a specific time period or periods.

Q14. Are the Company's current base rates cost-*based* consistent with the requirements of MCL 460.11(1)

A14. Yes. MCL 460.11(1) states:

> "…the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid."

In compliance with MCL 460.11(1), the Company's base rates are designed such that they collect the portion of the Company's overall revenue requirement that has been allocated to the relevant class through an approved COS study. In this way, the Company's rates are cost-*based*.

Q15. Are the Company's current rates cost-*aligned*?

A15. As stated above, the Company's current base rates are cost-*based* in that they are designed to collect the class revenue requirement established through an approved COS study. However, the Company's current rates are not cost-*aligned* in all cases, meaning the rate design does not necessarily reflect how and when costs are incurred.

Traditionally, prevailing metering and other technological capabilities limited the ability to design and implement more advanced rate structures that could better achieve cost-alignment. With the effectively full implementation of Advanced Metering Infrastructure (AMI) and other supporting technological advances, the Company is in a position to propose meaningful steps toward more cost-aligned rates. I discuss the benefits of more cost-aligned rates later in my testimony.

Q16. Given how and when costs are incurred by the Company, what is the most appropriate rate design to ensure cost-alignment?

A16. As described above, the Company incurs three basic types of costs – energy-related, demand-related, and customer-related. As such, the most appropriate rate design to achieve cost-alignment would reflect these underlying drivers of cost and incorporate an energy charge, a demand-based charge, and a customer charge. This is generally referred to as a "three-part" rate design. More specifically, this rate design would:

- Collect energy-related costs through an energy charge. As described above, energy-related costs on a per kWh basis tend to increase as aggregate system usage increases and decrease as aggregate system usage decreases. Therefore, a Time of Use (TOU) energy charge is most appropriate for this category of costs to reflect this dynamic, with different pricing windows designed to encompass periods of significantly different system usage. When looking at the Company's cost structure, fuel, purchased power, and other variable Operations and Maintenance (O&M) costs are best collected through this mechanism.
- Collect demand-related costs through a demand-based charge. As described above, demand-related costs are incurred coincident with the peak demand that could be placed on an asset. As such, a demand charge could either be an "on-peak" demand charge with the "on-peak" time being set coincident with the peak being placed on the asset(s), or a Non-Coincident Peak (NCP) demand charge where the underlying asset is designed to meet demand during all times. When looking at the Company's cost structure, Transmissions costs, the Capacity portion of Power Supply costs, and a portion of Delivery costs are best collected through a demand charge.
- Collect customer-related costs through a fixed customer charge. As described above, given the nature of these costs, they cannot be assigned to a certain time period and do not vary based on customer usage. As such, the most appropriate mechanism to recover these costs is through a fixed monthly customer charge. Recovering these costs through either an energy charge or a demand charge incorrectly assumes these costs vary based on some characteristic of customer usage. When looking at the Company's cost

structure, customer-related charges such as billing and a portion of Delivery costs are best collected through a customer charge.

Q17. Why is it important for rates to be cost-aligned?

A17. The two key overarching benefits of cost-aligned rates are that they send proper pricing signals, thereby promoting efficient and low-cost asset use, and that they promote equitable recovery of costs:

- Send proper pricing signals. Cost-aligned rates signal to customers that not only does the total volume of energy they consume drive costs, but so does the timing of that consumption and the peak demand they are placing on the system.

  In this way, cost-aligned rates promote efficient, low-cost asset use. Efficiency, both at an individual asset and system level, can be measured by load factor. Load factor divides the actual usage being placed on an asset or assets over a given time by the theoretical usage if the asset or assets were always being operated at its peak demand. It is preferable for assets and systems to operate with high load factors, as this is more efficient usage. Low load factors indicate that an asset was built to meet a peak load but is underutilized the majority of the time. In other words, the usage of the asset is “peaky”. Sending pricing signals that encourage less “peaky” behavior, if that behavior were realized, would allow the Company over the long-term to more efficiently build, operate, and maintain the system.

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Under cost-aligned rates, customers that choose to respond to the pricing signals and modify their load to have more efficient usage would be able to lower their bill.

- Ensure equitable recovery of costs. Having cost-aligned rates better ensures that customers are equitably paying for their specific usage of the system. Individual customers within a single class, even if their total usage is similar, can drive very different costs on the system. For example, consider two theoretical customers, Customer A and Customer B, that both use 500 kWh per month. Customer A has a monthly load factor of 100%, meaning they use the exact same amount of energy in every hour of the month. For a month with 30 days, this would equate to a peak demand (measured hourly) of ~0.7 kW. Customer B has a load factor of 10%, which would mean their peak demand (measured hourly) during the month is ~6.9 kW. Despite having the same total usage, Customer B's peak demand is almost ten times greater than Customer A's. As such, Customer B is driving significantly greater costs on the system given the Company must have the Power Supply and Delivery infrastructure in place to meet a much higher demand. Depending on when Customer B uses their energy, energy-related costs could also be higher or lower.

While this is an extreme case, it highlights the fact that customers can drive different levels of cost in the system depending on how they consume energy. Having cost-aligned rates ensures customers are paying their "fair share." In the example above, Customer B would pay more than Customer

A under cost-aligned rates, but would also be receiving the proper pricing signals that would encourage more efficient system use, as described above.

If rates are not cost-aligned, there is a risk customers who are using the system more efficiently will be paying more than their "fair share" and customers using the system less efficiently will be paying less than their "fair share." In effect, the more efficient users will be subsidizing the less efficient users. The appropriate way to address this subsidization is through cost-aligned rates.

Q18. If a three-part rate design is the most appropriate rate design, why does the Company not simply propose moving all customers to this type of rate?

A18. With limited exception, all the Company's primary and higher voltage customers currently take service on rate schedules which include energy charges, demand-based charges, and customer charges – the three elements of three-part rate design. Furthermore, commercial secondary customers taking service under Rate Schedule D4 are also subject to all three elements of three-part rate design.

For residential and the remaining commercial customers, the "three-part" rate design described above would be a change from the D1 (Residential Service Rate - Base) and D3 (General Service) rates that currently serve the vast majority of these customers. A three-part rate design would potentially introduce multiple new structures or changes for these customers.

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As described above, the Company considers incrementalism an important factor when contemplating new rates or rate design changes. Given that, the prudent path forward is to incrementally move towards more cost-aligned rates. The Company acknowledges this approach will take time, but it will better allow customers to become comfortable with more advanced rate designs, and will allow the Company to better learn from customers about their experience, understanding, and satisfaction with these new rate structures.

In support of that approach, the Company is proposing such incremental steps in this case. The Company will continue to consider whether to propose additional incremental steps in future cases.

Q19. As it applies to the Company's second principle, what does it mean to provide "optionality"?

A19. Providing optionality essentially means giving an individual customer multiple rate options under which they can take service. Optionality can be achieved through both base service rates as well as through rate Riders or other provisions that respond to more specific customer needs or preferences, where appropriate.

Q20. Why is it important to provide optionality?

A20. The Company appreciates that different customers have different needs, preferences, and levels of ability when it comes to managing their usage. Some customers may prefer simple rates that tend to remain more constant over time, while others may be comfortable with more complex rates that allow the customer to more actively modify their usage to manage their bill.

Customers are more likely to engage and leverage a rate that matches their needs and preferences, so offering rate optionality also increases the chance of a rate being a "good fit" for an individual customer. This should in turn drive increased engagement with the rate, more active usage management, and improved customer satisfaction.

Q21. How can the Company offer optionality while also ensuring cost-alignment?

A21. The Company believes it is possible to offer multiple rate options to an individual customer that are all cost-aligned. For example, I have described above how the most appropriate mechanism for recovery of fuel and purchased power costs is a TOU energy charge. However, the structure of the TOU energy charge can be made more or less complex by adjusting things like the number of pricing windows. A simple TOU rate could employ a structure with two pricing windows, such as an "on-peak" window and an "off-peak" window. More complex structures could incorporate more windows, like a third "mid-peak" window. Taken to the extreme, the pricing windows could be set differently for each hour based on expected or actual market conditions.

Different rate options could be designed to incorporate different levels of complexity to meet the different preferences of the Company's customers. At the same time, the rates could remain cost-aligned and adequately reflect the underlying drivers of cost.

Q22. As it applies to the Company's third principle, what does it mean for a rate to "enable broad adoption"?

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A22. Enabling broad adoption means making an individual rate available to as many customers as possible. To enable broad adoption, barriers to access must be carefully considered and only implemented when there is a clear need to do so. The barriers could include separate metering/infrastructure requirements, technology requirements, customer eligibility requirements, etc.

Q23. Why is it important to enable broad adoption of rates?

A23. The Company serves customers that vary greatly across age, income level, geography, and energy usage. Certain customer groups, such as fixed-income customers or low-income customers, may not have the means to meet separate metering or other technology requirements to take service under a rate. Other customer groups, such as renters, may be prohibited from meeting certain requirements or lack the physical space to do so.

With that said, these same customers may benefit from access to a rate because it aligns well with their needs, preferences, and/or abilities to manage their usage. Enabling broad adoption ultimately enhances customer optionality and results in the same benefits described above - increased engagement with their chosen rate, more active usage management, and improved customer satisfaction.

Q24. Do the new rates or rate changes discussed later in your testimony align with these principles and other considerations?

A24. Yes. As I describe each new rate or rate design change, I will explain how the Company used these principles and other considerations to guide our proposals.

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<u>Time-of-Use (TOU) Full implementation – Background and Overview</u>

Q25. Please describe the Company's recent history as it relates to TOU rates

A25. DTE has offered several residential time of use and/or seasonal rate products, such as Rate Schedules D1.1 (Interruptible Space-Conditioning Service Rate), D1.2 (Residential Time-of-Day Service Rate), D1.7 (Geothermal Time-of-Day Rate), D1.8 (Dynamic Peak Pricing Rate), D1.9 (Electric Vehicle Rate), and D2 (Residential Space Heating Rate). The most recent residential time of use / seasonal products to be offered include two pilot programs, Rate Schedules D1-A and D1-B, the general history of which I describe below.

In the April 18, 2018 order in Case No. U-18255, pp. 81-82, the Commission directed DTE Electric to include in its next rate case filing a summer on-peak rate for non-capacity charges for Rate Schedule D1 (residential customers). In the May 2, 2019 order in Case No. U-20162, pp. 162-165, the Commission adopted an implementation plan for this transition, and directed DTE Electric to test capacity and non-capacity rates through pilots. Both Rate Schedules D1-A and D1-B, along with the broader Advanced Customer Pricing Pilot (ACPP), were approved by the Commission in the September 26, 2019 order in Case No. U-20602, p. 3, which stated, "*The Commission views the approval of these two pilots as necessary to implement the Commission's decisions and guidance from prior rate case orders. The Commission believes there is value to be gained by the utility, the Commission, and ratepayers from these pilot programs, including learning about customers' reaction to the rate offerings and different outreach and communication methods. The Commission stresses the importance of customer education for the successful implementation of summer peak pricing rates.*"

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Each of the new TOU pilot rates were to be offered to 105,000 residential customers on an opt-in basis, with target enrollment on each rate of 2,500 customers who affirmatively chose to opt-in, after which additional customers would be allowed to participate at the Company's discretion.

Each of the pilot rates was offered to an additional 5,000 residential customers on an opt-out basis as well, meaning these customers were notified that they were being placed onto one of the two rates before they became effective, and then had the opportunity to "opt-out" and remain on their legacy rate by notifying the Company either by calling the contact center or using the Company's self-service online functionality. Absent this proactive notification from the customer, the customers were automatically transitioned to TOU rates in the Spring of 2021.

Rate Schedules D1-A and D1-B both vary by time of day and by season. Both have an on-peak period consisting of 3:00 pm to 7:00 pm, Monday-Friday (with an off-peak period consisting of all other times), and on-peak rates which are different for June-September versus October-May.

D1-A was designed with a power supply non-capacity rate that varies by time and month as described above. The power supply non-capacity rate differential between on-peak and off-peak is derived from differences in historical Locational Marginal Prices (LMPs) for the corresponding seasonal and intraday periods. The power supply capacity rate is a "flat" per kWh energy charge, meaning the per kWh price remains constant throughout the year and does not vary based on the time of the day, the day of the month, or the month of the year.

D1-B was designed with both power supply non-capacity and capacity rates that vary by time and month as described above. The differential between on peak and off peak are again based on historical locational marginal prices for the corresponding seasonal and intraday periods. However, instead of being based on the absolute difference between the different LMPs, the difference is based on the relative difference.

Customers offered these pilot rates on an opt-in basis began enrolling onto the rate in March 2021. The rates became effective for customers being offered them on an opt-out basis in April 2021. The pilot is ongoing at the time of this filing.

Q26. Is the Company proposing a full implementation of TOU rates?

A26. Yes, the Company is proposing a full implementation of TOU rates using the proposed Rate Schedule D1.11 (Residential Service Rate – Standard TOU), which is supported by Company Witness Willis. As described below and also by Company Witness Willis, this rate schedule mimics the structure of the legacy rate D1-A (Residential Advanced Pricing Pilot A, TOU I) which was tested during the Company's ACPP that I described above.

Q27. What are the key elements of the Company's TOU Full Implementation proposal?

A27. There are five main elements of the Company's TOU Full Implementation proposal which will be supported by the following Company witnesses:

- Rate design. I will describe below the key components of the Company's proposed TOU Full Implementation rate design. Company Witness Willis has prepared tariff D1.11 (Residential Service Rate – Standard TOU) at my direction reflecting these components.
- Customer transition strategy. I will describe below the key components of the Company's proposed TOU Full Implementation transition strategy.
- Customer outreach and education. Company Witness Burns will describe in his testimony the key components and associated costs of the Company's customer outreach and education proposal.
- Customer service. Company Witness Sparks will describe in his testimony the key components and associated costs of the Company's customer service proposal, including impacts to billing and the contact center.
- IT investment. Company Witness Pizzuti will describe in her testimony the IT projects and associated costs required to deliver the Company's TOU Full Implementation proposal.

Time-of-Use (TOU) Full implementation – Rate Design

Q28. What are the key rate design components of the Company's proposed D1.11 (Residential Service Rate – Standard TOU) rate?

A28. The Company's proposed rate design for TOU Full Implementation starts with the D1 (Residential Service Rate - Base) rate and adjusts the rate design for the Power Supply portion of costs. Specifically, those changes include:

- Introducing a TOU structure to the Non-Capacity portion of Power Supply

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- Eliminating the "inverted block rate" structure historically utilized for the Capacity portion of Power Supply, and instead implementing a "flat" per kWh pricing structure

The Company's proposed D1.11 rate does not include any changes to the Delivery rate structure, and surcharges remain consistent with the D1 rate.

Q29. Why is the Company proposing to apply TOU pricing to only the Non-Capacity portion of Power Supply?

A29. As discussed previously in my testimony, the most appropriate costs to recover through per kWh TOU pricing are fuel and energy-related purchased power, both of which are contained within the Non-Capacity portion of Power Supply costs. Power Supply Capacity costs are most appropriately recovered through a demand-based charge. These rate designs best align with the underlying drivers of cost for the respective cost type, and therefore send the most accurate pricing signals to customers to encourage efficient, low-cost asset use. As such, the Company is proposing to apply TOU pricing to only the Non-Capacity portion of Power Supply costs.

Q30. What is the Company's proposed rate design for the Capacity portion of Power Supply?

A30. The Company is proposing to move to a "flat" per kWh energy price for the Capacity portion of Power Supply. A "flat" price remains constant throughout the year and does not vary based on the time of the day, the day of the month, or the month of the year.

The proposed structure would replace the "inverted block rate" incorporated into the Company's D1 rate.

Q31. Why is the Company proposing to not use the "inverted block rate" for Power Supply Capacity costs for TOU Full Implementation?

A31. The "inverted block rate" sends a blunt pricing signal that simply encourages customers to use less energy so that a smaller portion of their usage is subject to the higher-priced "block" (i.e., above 17 kWh per day). However, the "inverted block rate" does not provide any type of signal to customers for *when* to reduce their usage.

With the introduction of the TOU pricing structure applied to the Non-Capacity portion of Power Supply, customers will already be receiving a more nuanced pricing signal that encourages them to reduce their usage during the time of highest aggregate system demand. As such, if the "inverted block rate" were retained, it would send a superfluous, and potentially confusing, pricing signal to customers. Therefore, the Company is proposing to not use this structure for Power Supply Capacity costs in its Rate Schedule D1.11.

Q32. Is the Company proposing any rate design changes for Delivery costs?

A32. No, the Company's proposal retains the D1 rate structure, which incorporates "flat" energy pricing and a fixed service charge.

Q33. Is the Company's rate design proposal consistent with Consumers Energy's recent TOU Full Implementation approved in Case No. U-20134?

A33. Not entirely. The Company's proposed rate structure deviates from Consumers Energy's TOU rate in two key ways:

- The Company is proposing that TOU pricing only apply to the Non-Capacity portion of Power Supply. Consumers Energy's rate applies TOU pricing to both the Capacity and Non-Capacity portion of Power Supply.
- The Company is proposing that TOU pricing be effective during the entire year. Consumers Energy's rate has TOU pricing effective only during the summer months.

Q34. Why is the Company proposing a TOU rate design that is different from the design approved for Consumers Energy's TOU Full Implementation?

A34. As it relates to the application of TOU rates, the Company believes that per kWh TOU rates are most appropriate to recover only Power Supply Non-Capacity costs as I have discussed earlier in my testimony. As such, the Company's proposed structure represents the most appropriate use of this structure.

In addition, applying TOU pricing to Power Supply Non-Capacity rates only as the Company proposes will help limit potential bill impacts. Customers will be better able to get comfortable with the new rate structure without being subject to a higher pricing differential between on-peak and off-peak periods.

As it relates to the effective period of TOU rates, the Company considers it appropriate to have the TOU structure effective year-round for two key reasons:

- Customer understanding. By making the TOU structure effective year-round, the Company can provide a consistent message on how customers should manage their usage to leverage the rate because customers will be subject to consistent pricing signals. This promotes customer understanding and should help increase engagement with the rate. Employing the TOU structure only during the summer months would require changing customer pricing signals two times during the year – once when entering the summer months signaling the start of TOU pricing, and once after the summer months when "flat" pricing would take effect. The Company believes this has the risk of not only confusing customers and potentially resulting in reduced customer satisfaction, but also of not resulting in a lasting shift in customer behavior.

Furthermore, providing consistent messaging and price signals that encourage off-peak utilization of energy, regardless of the time of year, will be important as the deployment of electric vehicles continues to accelerate, leading to greater levels of year-round energy usage.

- Supported by market pricing. Even in non-summer months there is a meaningful difference between on-peak and off-peak market energy prices. As such, the Company considers it appropriate to retain the TOU structure in non-summer months to reflect these differences. With that said, the on-peak to off-peak market energy price differential is greater during the summer months, which is why the Company is proposing to have "summer" pricing and "non-summer" pricing as described by Company Witness Willis.

In summary, the Company's proposal takes an important step in more broadly establishing TOU rates, while also mitigating potential negative customer impacts.

Q35. What has the Company learned from its ACPP that supports its proposal?

A35. As I described earlier in my testimony, the ACPP has and continues to test two distinct rate structures. The first rate (D1-A) has the same structure that the Company is proposing in this case for TOU Full Implementation. D1-A introduces TOU pricing to the Non-Capacity portion of Power Supply and "flat" energy pricing for the Capacity portion of Power Supply. The second rate (D1-B) introduces TOU pricing to both the Non-Capacity and Capacity portions of Power Supply.

Using data from the pilot captured during summer months (i.e., June-September 2021), the Company assessed the on-peak load impacts of customers under both rate structures. Specifically, the Company assessed the roughly 8,600 customers that were enrolled under the "opt-out" enrollment strategy during this time. As described previously, these customers had the option to leave the pilot program but did not choose to do so.

Usage data during this time was analyzed by comparing pilot participants against a control group made up of non-participants that had similar characteristics in terms of historical usage, geography, age, and income level. In this way, the analysis attempted to isolate and determine the behavior change that could be attributed to a customer moving to a TOU rate.

The analysis described above suggests that there is no meaningful difference to expected aggregate on-peak load impacts when comparing the two different rate structures being tested in the pilot. In both cases, on-peak load impacts are expected to be less than 1% of total load. Figure 1 below summarizes the results.

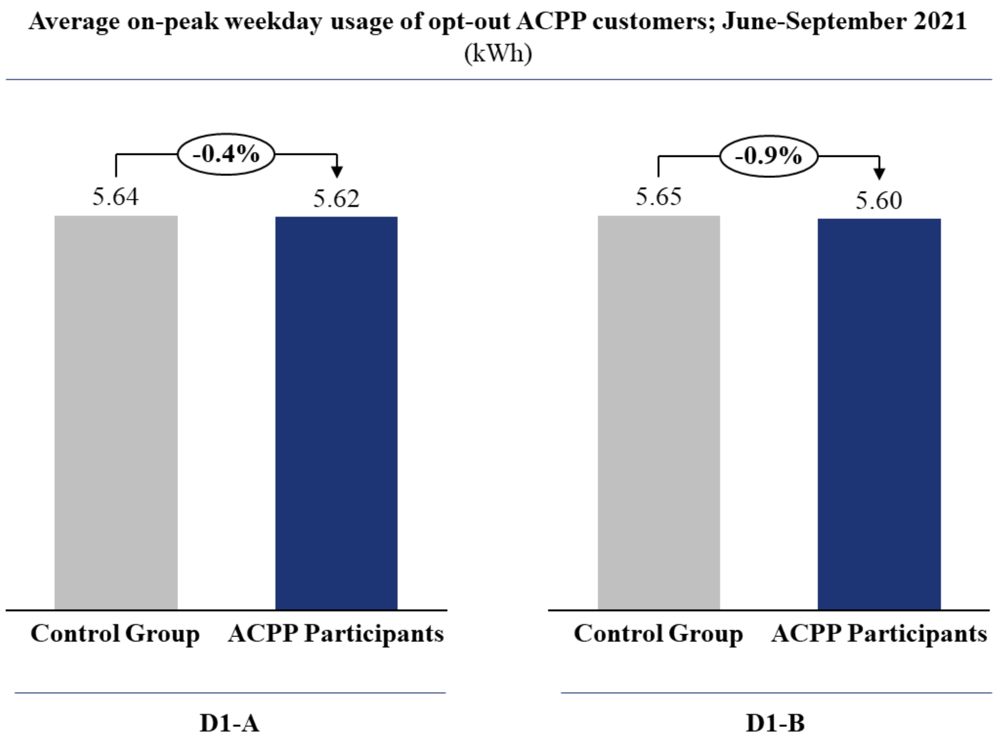

Figure 1: Comparison of average on-peak weekday usage between ACPP opt-out participants and non-participants; June-September 2021

As can be seen in the figure above, the expected average impact is likely to be similar by implementing rate D1-A as it would be if the Company were to implement rate D1-B.

Given this information, and in addition to the arguments made previously, the Company does not consider it prudent to subject customers to a higher pricing differential when aggregate load impacts are likely to be similar and a higher pricing differential could subject individual customers to more severe bill impacts. Instead, a more appropriate path forward is to implement the Company's proposed rate and continue to track customer understanding, behavior, and sentiment toward TOU rates. As mentioned previously, the Company will continue to assess, and potentially propose, new rates or rate design changes that achieve the principles outlined in the first section of my testimony.

Q36. Has the Company prepared a proposed TOU Full Implementation tariff reflecting these key components?

A36. Yes. I have directed Company Witness Willis to prepare Rate Schedule D1.11 (Residential Service Rate – Standard TOU) reflecting these key components. In addition, Company Witness Willis will describe the mechanics and calculation of on-peak and off-peak pricing and the disposition of the legacy D1-A and D1-B rates that are being tested as part of the ACPP.

Q37. Would the Company need to make any additional adjustments if a rate design other than what the Company has proposed is ordered?

A37. Yes, if the Commission orders a rate design other than that proposed by the Company as I have described in this section, the Commission should also allow the Company to adjust the projected billing determinants associated with the ordered rate design.

Depending on the ordered rate design, customer behavior that is different than what underlies the pricing of the Company's proposed D1.11 rate could potentially be expected. For example, a higher on-peak to off-peak pricing differential could result in lower expected on-peak usage than was assumed for the Company's proposed D1.11 rate. As such, the Company should be allowed to update its projected billing determinants if a different rate design is ordered to ensure it is able to fully recover the costs allocated to the D1/Other cost of service class.

<u>Time-of-Use (TOU) Full implementation – Customer Transition Strategy</u>

Q38. What are the key components of the Company's proposed TOU Full Implementation customer transition strategy?

A38. The Company is proposing to utilize an "opt-out" enrollment strategy for its TOU Full Implementation. Under this structure, all residential customers taking service on the D1 (Residential Service Rate – Base) rate would be given at least sixty days' notice that they are being transitioned to the D1.11 (Residential Service Rate – Standard TOU) rate. Prior to being transitioned onto the D1.11 rate, a customer could opt-out of the transition by notifying the Company of their desire to do so.

The Company anticipates that customers will be able to provide notification of their desire to opt-out through an online tool or by calling the Company's contact center.

Customers that have notified the Company of their desire to opt-out would not be transitioned onto the D1.11 rate and would instead remain on the D1 rate. Absent a notification from the customer, the Company would automatically transition a customer onto the D1.11 rate as described later in my testimony.

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Once transitioned onto the D1.11 rate, customers would be able to annually change rates and take service under any rate schedule for which they are eligible, including the D1 rate. In other words, the D1 rate would be retained and made available to any residential customers meeting its eligibility requirements. As reflected in the proposed D1.11 tariff, the Company also intends to allow customers that were transitioned to the D1.11 rate to change rates and take service on D1 or any other rate for which they are eligible until September 30, 2023. Any such customer remaining on the rate after September 30, 2023 will be subject to the Company's typical 12-month service requirement for residential TOU rates.

It is the Company's intent to maintain a high level of enrollment on the D1.11 rate and will take all reasonable actions with its customers to do so. In support of this objective, the D1.11 rate would become the default rate for new residential customers and customers changing premises, similar to how the D1 rate acts as the default rate today. New or moving customers would still be able to take service under the D1 rate but would have to proactively choose to do so. Absent this proactive choice, they would be placed on the D1.11 rate. This should help support a high level of enrollment on the D1.11 rate.

Q39. When does the Company anticipate this transition to occur?

A39. In its February 4, 2021 Order in Case No. U-20602 ("February Order"), p. 6, the Commission outlined its expectation for TOU Full Implementation, stating:

> "THEREFORE, IT IS ORDERED that DTE Electric Company…file its full plan for implementation of summer on-peak rates for capacity and non-capacity

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> charges in time to achieve full implementation of the new rates for summer 2023."

As such, the Company expects to complete all customer transitions to the D1.11 rate by May 31, 2023. While the final solution is not yet developed, the Company anticipates that a phased transition would occur during the first half of 2023, whereby customers would be transitioned to the rate over time as to not overstress IT systems, contact center resources, etc.

Q40. What has the Company learned from its Advanced Customer Pricing Pilot (ACPP) that supports its proposal?

A40. As discussed above, the ACPP specifically tested an opt-out structure, and therefore the Company has driven robust insights into how it should prepare for its TOU Full Implementation. Specific to the opt-out structure, to date the Company has experienced a 5.6% opt-out rate. The Company's goal is for the percentage of "opt-out customers" to be lower than what was experienced in the pilot and will endeavor through communications and the deployment of tools to help customers understand the benefits of the TOU rate.

Q41. Why does the Company believe this is the most appropriate transition strategy?

A41. The Company considers an opt-out transition strategy to be most appropriate for two key reasons:

- It achieves the Commission's desire to move to TOU rates. As stated above, the Company's goal is to maximize the number of customers that take service under the D1.11 rate, even above the roughly 94% of pilot participants that did not elect to opt-out.

- It allows for optionality. The Company appreciates that all customers may not want to take service under a TOU structure, as evidenced by the opt-out rate experienced during the ACPP. As such, the Company considers it appropriate to provide these customers with an option to remain on their current rate if they so desire. This optionality should help mitigate risk of customer dissatisfaction.

Q42. Is the Company's proposed transition strategy consistent with Commission direction on the transition to TOU rates?

A42. Yes. In its February Order, p. 5, the Commission communicated its expectations by stating:

> "…the Commission clarifies its expectation that, while the ACPP program includes both opt-in and opt-out enrollment paths for each of the approved pilot rates, the ultimate program to be fully implemented in 2023 will be either a default or opt-out program that more closely mirrors cost of service."

As the proposed TOU Full Implementation employs an opt-out structure, it meets the Commission's direction.

Q43. Is the Company proposing any changes to the D1 (Residential Service Rate - Base) rate given its proposal for TOU Full Implementation described above?

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A43. As described above, the Company is proposing that the D1 rate be maintained for residential customers that notify the Company of their desire to opt-out of the transition to the D1.11 rate, or that otherwise proactively choose to take service under it. As such, the Company is not proposing any changes to the structure or eligibility of the D1 rate.

Q44. Is the Company proposing any changes to its residential Cost of Service treatment given its proposal for TOU Full Implementation described above?

A44. The Company is not proposing any changes to its Cost of Service (COS) classes with the introduction of the D1.11 rate. The Company proposes that both the proposed D1.11 rate and the existing D1 rate be a part of the D1/Other cost of service class. This is appropriate as there are currently no customers taking service on the D1.11 rate and the Company cannot forecast with any certainty which customers will elect to opt-out of the transition to the D1.11 rate.

However, once the transition to the D1.11 rate is complete and movement between rates has stabilized, the Company plans to assess if creating a new COS class containing only the existing D1 rate would be appropriate. At that time the Company would have better clarity on both the number and the aggregate usage characteristics of customers electing to remain on the existing D1 rate and could better assess if a separate COS class is warranted.

Q45. How does the Company propose to handle customers currently participating in the ACPP on either legacy rate D1-A (Residential Advanced Pricing Pilot A,

Time of Use I) or rate D1-B (Residential Advanced Pricing Pilot B, Time of Use II)?

A45. Consistent with the transition strategy described above, the Company anticipates it would provide customers taking service under D1-A or D1-B with at least sixty days' notice that they are being transitioned to the D1.11 rate. The Company appreciates that the specific messaging provided to D1-A and D1-B customers may need to be different than what is provided to D1 customers given their involvement in the ACPP.

Customers notifying the Company of their desire to opt-out of the transition would not be transitioned onto the D1.11 rate and would instead be placed on the D1 rate. Absent a notification from the customer, the Company would automatically transition a customer onto the D1.11 rate.

As described by Company Witness Willis, the legacy D1-A and D1-B rates would be retired and removed from the Company's rate book once all Pilot customers are transitioned to other rates.

Q46. What are the one-time project costs associated with the Company's TOU Full Implementation?

A46. Figure 2 below summarizes both the total capital and total O&M one-time project costs associated with the Company's proposal that I have described above. The table also indicates the Company witness that will describe and support each category of costs, including timing, within their testimony.

Cost Category	One-Time Project Capital Costs ($M)	One-Time Project O&M Costs ($M)	Supporting Company Witness
Customer Outreach	$-	$8.1M	Burns
Customer Service	$-	$4.9M	Sparks
Customer IT	$31.7M	$4.1M	Pizzuti
Total	**$31.7M**	**$17.1M**	

Figure 2: Estimated TOU Full Implementation one-time project costs and supporting witnesses

Voluntary residential "Stable Bill Service Level" demand-based tariff

Q47. Please describe the Company's recent history as it relates to residential demand rates.

A47. DTE does not currently offer any residential rate schedules that utilize demand rates or demand-based charges. However, DTE did propose pilot residential demand rates as part of the case in which the D1-A and D1-B rates discussed above were initially approved (Case No. U-20602). In that case, DTE proposed residential rate pilots which included distribution demand rates. Though the September 26, 2019 Commission order issued in Case No. U-20602 noted that Staff had reviewed DTE's application and supported the Company's proposals (p. 2 of order), the Commission did not approve the proposed residential demand pilots, finding they should be addressed separately and stating, "*Additional discussions regarding demand charges would be warranted prior to implementation.*" (pp. 3-4 of order)

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Q48. What are the overall benefits to customers of taking service under a rate that incorporates demand-based charges?

A48. Demand-based rates provide customers an additional way to manage their usage and better control their bill that hasn't traditionally been available to residential customers. Rates that are predominantly volumetric in nature, like the Company's D1 (Residential Service Rate – Base) rate provide a single way for customers to manage their usage and potentially reduce their bill. Specifically, customers taking service under these types of rates can only lower their bill by *reducing* their aggregate usage.

TOU rates, like the Company's proposed D1.11 (Residential Service Rate – Standard TOU) or existing D1.2 (Residential Service Rate – Enhanced TOU) rates provide a second way for customers to manage their usage and potentially reduce their bill. Specifically, customers taking service under these types of rates can also *shift* their usage from on-peak periods to off-peak periods to lower their bill. These customers have two tools to control their bill – *reduce* and *shift*.

Rates that incorporate charges based on a customer's demand offer a third way for customers to manage their usage and potentially reduce their bill. Customers taking service under these types of rates can also *stagger* their usage in order to reduce their peak demand and lower their bill. For example, instead of using multiple high-demand appliances at once (e.g., electric clothes dryer, air conditioning, electric oven, etc.), customers could *stagger* their usage and use these appliances at different times, so their peak demand throughout the day and month is less. These customers then have three tools to control their bill – *reduce, shift,* and *stagger*.

As customers become more sophisticated and tools to actively manage usage become more mature, providing additional ways for customers to control the size of their bill can have tremendous value. Offering a rate option that provides customers with this added flexibility clearly increases customers' ability to manage their usage and control the size of their bill.

Q49. Is the Company proposing the introduction of a residential demand-based tariff?

A49. Yes, the Company is proposing to establish Rate Schedule D1.12 (Residential Service Rate – Stable Bill Service Level), which would be a voluntary tariff available to all residential customers.

Q50. What are the key components of the proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate?

A50. The D1.12 rate consists of three main components:

- A per kWh TOU energy charge to recover energy-related costs, such as fuel and purchased power
- A fixed monthly Delivery Service charge set equal to the Delivery Service charge incorporated into other base residential service tariffs
- A monthly Customer Service Level charge to recover all other costs not collected through the energy and Delivery Service charges described above. The Customer Service Level charge would be based on the demand an individual customer places on the system

I further describe each of these components later in my testimony.

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Q51. Please further describe the per kWh TOU energy charge component of the proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate.

A51. Under the proposed D1.12 rate, the per kWh TOU energy charge is applied to Power Supply Non-Capacity costs as these are generally energy-related costs. As discussed earlier in my testimony, it is appropriate to recover energy-related costs through an energy charge.

As described by Company Witness Willis, the TOU structure of this charge is designed to mimic the Company's proposed D1.11 (Residential Service Rate – Standard TOU) rate to ensure consistency across rates. Both the TOU pricing windows and the methodology for setting on-peak/off-peak pricing differentials would be consistent between D1.11 and D1.12.

Q52. Please further describe the fixed Delivery Service charge component of the proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate.

A52. The fixed Delivery Service charge is designed to match the Company's other residential service rate offerings. While the Company has proposed an increase to this charge in the past, it is not proposing an increase as part of its D1.12 rate proposal.

Q53. Please further describe the Customer Service Level charge component of the proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate.

A53. The Customer Service Level charge is designed to equitably recover all other costs not being collected through the per kWh TOU energy charge or the Delivery Service

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charge. The Customer Service Level charge would recover those power supply capacity and distribution costs currently recovered on a volumetric basis. The basic structure is that each customer taking service under the D1.12 rate would be assigned to a "service level" based on the demands they place on the system. The service levels are pre-defined such that there is perfect clarity about why a customer is assigned to a specific service level.

Each service level has a fixed monthly charge associated it, with higher service levels being subjected to higher monthly charges.

Q54. Under the proposed design, how would a customer's service level be determined?

A54. A customer's service level would be determined by first calculating the customer's "service size", and then using that to assign the customer to a pre-defined service level.

A customer's "service size" would be determined by calculating the average of the customer's three highest use hours during the previous twelve billing cycles, inclusive of the customer's current billing cycle. As defined for this rate, hourly use is the average demand, in kW, over a clock hour. The Company proposes that the three highest use hours must occur on different calendar days. For example, if over the past twelve billing cycles a customer's highest use hours (assuming they occurred on different calendar days) were 4.25 kW, 4.75 kW, and 5.5 kW, then the customers "service size" would be calculated at 4.83 kW.

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Once a customer's "service size" has been calculated, the customer would be assigned to a service level based on pre-defined thresholds. The proposed thresholds are outlined below in Figure 3.

Service Level	Service Size			
1			less than	1.00 kW
2	at least	1.00 kW	but less than	2.00 kW
3	at least	2.00 kW	but less than	3.00 kW
4	at least	3.00 kW	but less than	4.00 kW
5	at least	4.00 kW	but less than	5.00 kW
6	at least	5.00 kW	but less than	6.00 kW
7	at least	6.00 kW	but less than	7.00 kW
8	at least	7.00 kW	but less than	8.00 kW
9	at least	8.00 kW	but less than	9.00 kW
10	at least	9.00 kW		

Figure 3: Proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate service levels

Continuing from the example presented above, a customer with a "service size" of 4.83 kW would be assigned to Service Level 5.

Q55. Under the proposed design, how would the Company determine the service level for a customer without twelve months of billing history?

A55. If a customer does not have at least twelve months of billing history, the Company proposes to use as much billing history as is available for the individual customer. For example, if a new customer wishes to take service under the D1.12 rate, during the customer's first billing cycle the Company would use only that billing cycle

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usage to calculate the customer's service size and assign them to a service level. During the customers second billing cycle, the Company would use the first two billing cycles to determine service size and service level, and so on. Once a customer has twelve months of billing history, the Company would only use the trailing twelve months to determine service size and assign the customer to a service level, as described above.

If an existing customer desires to switch rates onto the D1.12 rate, the Company proposes to use twelve months of usage history, or as much usage history as is available if less than twelve months, regardless of if that usage was served under a different rate.

Q56. Why is the Company proposing to use twelve months of usage history to determine a customer's "service size"?

A56. Using twelve months of billing history to determine a customer's "service size" results in a much more stable bill than is provided under the Company's other base rates. Under the proposed D1.12 rate design, if a customer's usage from year-to-year is consistent, then they could expect to remain in the same service level, and be subject to a consistent service level charge, subject to changes ordered during general rate cases. From month to month, only the energy charge portion of their bill would vary based on their usage during that month.

With that said, customers would maintain the ability to change service levels and be subjected to higher or lower service level charges if they either make behavioral changes (e.g., *staggering* their usage to manage high use hours) or by fundamentally

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changing their load (e.g., installing more efficient appliances to *reduce* their overall load). The Company believes using twelve months of usage history to determine a customer's service size strikes the right balance between providing bill stability and also allowing customers to manage their usage and control the size of their bill.

In addition, using twelve months of usage history to determine a customer's "service size" better ensures equitable recovery of costs by protecting against inefficient users that are driving an outsized level of costs in the system. Under the proposed D1.12 rate design, inefficient users that have relatively high usage "spikes" but otherwise keep usage low would have their service level determined based on these "spikes" and would be subject to the associated service level charge in subsequent months. In other words, they would be more equitably charged for the demands they are placing on the system.

Q57. Why is the Company not proposing to simply use a customer's single highest use hour during the trailing twelve months to determine that customer's service level?

A57. The Company appreciates that the structure of the D1.12 is different than what a typical residential customer may be used to. As such, the Company looked for opportunities to provide appropriate customer-friendly features to help ensure a smooth transition onto the rate. As described above, two of these customer-friendly features are:

- Calculating a customer's "service size" by averaging the three highest use hours during the trailing twelve billing cycles, instead of simply using the highest use hour. This provides customers taking service under the D1.12 rate a level of protection against a single unusually high-use hour.

- Requiring that a customer's three highest use hours occur on separate calendar days. This provides customers taking service under the D1.12 rate a level of protection against a single unusually high-use day.

Q58. How would a customer taking service under the proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate be made aware of what service level they are in?

A58. The Company envisions updating the bill and online account to display the pertinent information related to service level for any customer taking service under the proposed D1.12 rate. As an illustrative example, Figure 4 displays information that could be provided to customers.

> You are taking service under DTE's Stable Bill offering!
>
> Your service level was determined based on the following:
> - Highest use hour 1: 7/7/24 from 1:00-2:00pm – 4.25 kWh
> - Highest use hour 2: 9/3/24 from 6:00-7:00pm – 4.53 kWh
> - Highest use hour 3: 11/22/24 from 10:00-11:00am – 5.72 kWh
>
> The average of your highest use hours is 4.83 kWh. This puts you in Service Level 5.

Figure 4: Illustrative information that could be provided to customers taking service under the D1.12 rate

The above information provides the customer with transparency in how their service level was determined, and when their highest hours were set. This provides customers with clear and compelling pricing signal to manage their usage and use the system more efficiently. If customers are able to manage their high-use hours, they could move to a lower service level over time and be subjected to a lower service level charge.

Q59. How does the proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate provide more bill stability?

A59. As discussed above, the proposed D1.12 rate uses a customer's previous twelve months of usage history to determine that customer's "service size". Under this construct, customers that have consistent use from year to year could expect to remain in the same service level and be subjected to a relatively consistent service level charge. From month to month, only the energy charge portion of their bill would change based on their actual usage during the month.

To demonstrate this phenomenon, the Company analyzed the usage history of 10,000 randomly selected residential customers. For each customer, monthly bills were simulated based on their actual monthly usage during 2019-2020 under the Company's proposed D1.11 (Residential Service Rate – Standard TOU) rate and the proposed D1.12 rate. The Company then determined for each customer the difference between their highest bill and lowest bill during the two-year period.

The results of this analysis are captured below in Figure 5. Under the proposed D1.11 rate, over 80% of customers would be subject to a high bill that is more than double their low bill during the analysis period. Under the proposed D1.12 rate, the portion of customers with a high bill more than double their low bill drops to less

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than 10%. In other words, the proposed D1.12 rate drastically reduces bill volatility as evidenced by the significantly reduced number of customers seeing a high bill more than double their low bill.

This increased bill stability is potentially extremely valuable for customers, such as those on fixed income or otherwise desiring a more consistent electric bill.

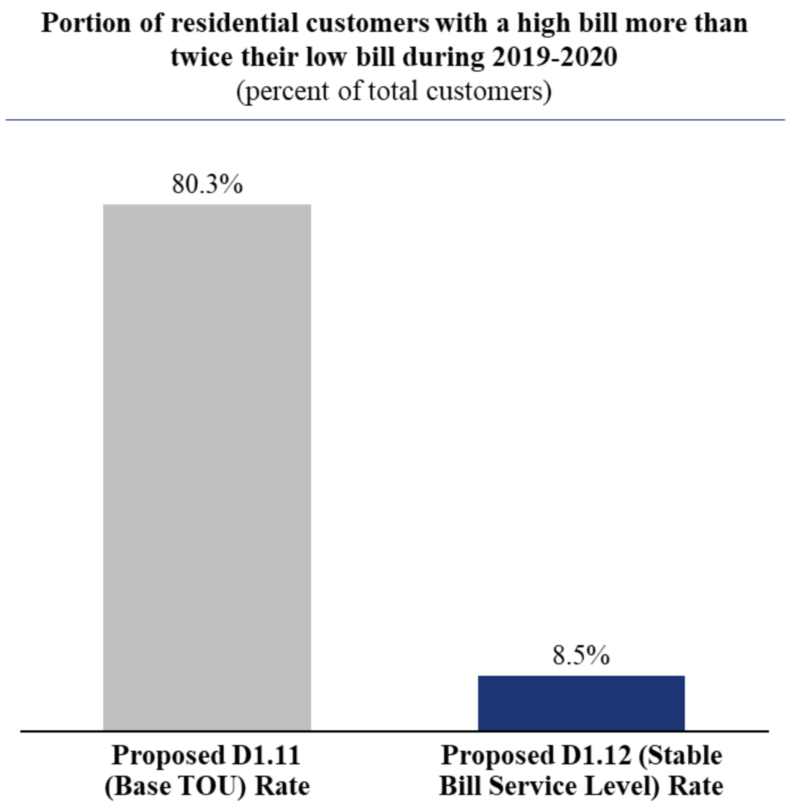

Figure 5: Customer Bill Volatility under proposed D1.11 rate vs. proposed D1.12 rate

Q60. How is the proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate different from a traditional "fixed bill" offering

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A60. A traditional “fixed bill” offering charges a customer a fixed monthly amount over the term of the agreement between the customer and the utility. In general, once the term and price have been agreed to by the customer, the monthly charge does not vary based on the customer’s actual usage during the agreement.

The price offered to the customer is likely based on an assessment of the customer’s historical usage, such that subsequent offers (i.e., after the initial fixed bill term) could be more or less expensive based on the customers usage during the current agreement. In this way, fixed bill offerings potentially send longer-term price signals to manage usage since future offers may depend on current usage.

Under this arrangement the utility, and by extension its other customers, are taking a risk that a fixed bill customer uses more energy than was estimated but is not paying for the increased costs of serving that load. As such, the utility likely charges a risk premium to the fixed bill customer to try to protect itself and its customers from this possibility.

The proposed D1.12 rate varies from a traditional fixed bill offering in two key ways:

- Near-term pricing signals are maintained. Unlike a traditional fixed bill offering, the proposed D1.12 rate incorporates a per kWh TOU energy charge. As such, customers taking service under this rate would continue to receive a pricing signal encouraging them to *reduce* overall usage, and to *shift* usage out of on-peak periods.

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As described above, customers taking service under the D1.12 rate would also receive a pricing signal to *stagger* their usage in order to manage their highest use hours. Unlike a traditional fixed bill offering where the monthly charge is decoupled from actual usage for an individual month, a customer taking service under the D1.12 rate could move to a higher or lower service level and be subjected to a higher or lower service level charge based on their current month's usage and the timing and size of their previous high-use hours.

- There is no risk to the utility or its other customers. The proposed D1.12 is cost-aligned as it appropriately charges customers for the demands they place on the system. If a customer reduces their use of the system over time, they will appropriately be moved to a lower service level and charged a decreased amount, and vice versa.

Q61. What are the bill impacts to customers taking service under the proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate?

A61. Consistent with the Company's overall approach to rate design, D1.12 is designed to be revenue-neutral to Rate Schedule D1. This means that if all D1 customers took service under the new rate, the Company would continue to collect the total portion of the Company's overall revenue requirement that has been allocated to D1. This has the effect of making the average bill impact zero when compared to the Company's Rate Schedule D1. Like with any new rate or rate change, the bill impact to a specific customer will depend on that customer's individual usage, including any behavior changes they make in response to the rate. As such, it is impossible to

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determine what the actual impacts will be without introducing the rate and assessing the usage and bills of the customers taking service under it.

While the average bill would not change, customers would have a third way to manage their usage and control their bill. Specifically, they could *stagger* their usage to better control the demand-based component of their bill.

Q62. Is the Company proposing a pilot program to test the proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate?

A62. No, the Company is not proposing a pilot program to test the proposed rate. Instead, it is the Company's intent to notify customers of the rate's availability and provide education about the new rate through traditional channels, such as listing the rate on the Company's "pricing options" website, sending customers email communications, etc. As such, the Company is not requesting approval of incremental marketing or customer service O&M costs to support the rate's deployment.

With that said, the Company plans on closely tracking customers' engagement with the proposed rate. As mentioned above, the only way to understand the actual usage and bill impacts of new rates or rate changes is to analyze customers that take service under the rate. Among other things, the Company would track and analyze the subscription rate, customer-level usage impacts, and bill impacts of the rate. The Company would plan to share the results of these activities with interested stakeholders.

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The Company intends to initially limit the number of customers taking service under the proposed D1.12 rate to 10,000 to ensure it can properly assess the impacts of the rate while also limiting the potential for unintended consequences. Customers taking service under both the D1.12 rate and Rider 18 would not count against this limit.

Q63. When would D1.12 (Residential Service Rate – Stable Bill Service Level) be available to residential customers?

A63. As described earlier in my testimony, TOU Full Implementation, including the introduction of the D1.11 (Residential Service Rate – Standard TOU) rate, will likely occur during the first half of 2023. The Company acknowledges that launching any new rate at the same time has the potential to overwhelm and/or confuse customers, which could result in reduced engagement with either rate and lower overall satisfaction.

As such, the Company anticipates that it would make the proposed D1.12 rate available to customers in the first quarter of 2024. This will give the Company time to complete and stabilize its TOU Full Implementation and give customers time to get comfortable with TOU rates before an additional rate option becomes available. The Company could accelerate or delay the launch of D1.12 depending on the conditions of the TOU Full Implementation.

Q64. Has the Company prepared a tariff reflecting the proposed D1.12 (Residential Service Rate – Stable Bill Service Leve) rate described above?

A64. Yes. I have directed Company Witness Willis to prepare a proposed D1.12 tariff that reflects the structure and pricing described above.

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Distributed Generation Program- Background and Overview

Q65. Please describe the Company's recent history as it relates to its Distributed Generation (DG) Program.

A65. Public Act 341 of 2016 included MCL 460.6a(14), which states in part, "*Within 1 year after the effective date of the amendatory act that added this subsection, the commission shall conduct a study on an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. In any rate case filed after June 1, 2018, the commission shall approve such a tariff for inclusion in the rates of all customers participating in a net metering or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211.*"

The Commission in its April 18, 2018 order in Case No. U-18383 then directed utilities to file, "*the Inflow/Outflow tariff, attached to [that] Order as Exhibit A*," and continued, "*the rate regulated utility may also file its own distributed generation tariff, if desired*." (p 18) The Company complied with this directive in its rate case filed July 6, 2018, Case No. U-20162, wherein DTE proposed the Rider 18 Distributed Generation Program, to replace Rider 16 Net Metering on a going forward basis. Rider 16 Net Metering customers who applied and were approved for Rider 16 before Rider 18 was enacted can retain their Rider 16 service for ten years from the date the premise began being billed on Rider 16. The Company proposed that Rider 18 distributed generation customers be subject to the following general rate structure:

- Inflow (energy the DG customer consumes from the Company's distribution system) charged at the retail rate of the underlying rate schedule.
- Outflow (energy exported from the customer's DG system to the Company's distribution system) credited at the monthly average real-time LMP for energy at the DTE Electric-appropriate load node
- A System Access Contribution (SAC) charge, which assigned a cost per kW AC of nameplate system capacity based on the system-cost responsibility of distributed generation customers. The charge was proposed to apply to customers taking service under rates without demand charges.

The Commission's May 2, 2019 Order in Case No. U-20162 approved an alternate version of the Company's proposed Rider 18. Total inflow was ordered to be charged at the retail rate of the underlying rate schedule, as had been proposed by the Company, however the Commission ordered the outflow credit be set at the Power Supply rate less Transmission (based on the customer's underlying rate schedule), and rejected the Company's proposed SAC charge.

In the Company' last filed rate case, Case No. U-20561, MPSC Staff argued in its testimony the Company should voluntarily raise the statutory cap that applies to DG customers (comprised of Rider 16 Net Metering customers and Rider 18 Distributed Generation customers). The Company declined to do so, explaining in rebuttal testimony in that case that doing so may have the unintended consequence of exposing the Company to uncapped revenue shifts and expose our non-DG customers to increased and improper cost subsidizations (See Case No. U-20561, 4T p. 496).

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Q66. Is the Company proposing changes to Rider 18 (Distributed Generation Program)?

A66. Yes, the Company is proposing making two changes to Rider 18:

- Setting the outflow credit, on a per kWh basis, to be the total of the following:
  - The average monthly MISO hourly LMP for the DTE Electric appropriate load node, calculated and applied separately for each pricing window for customers taking service on TOU rates.
  - A credit for avoided line losses as calculated through the Company's most recent line loss study.
- Requiring residential customers taking service under Rider 18 to also take service under the Company's proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate.

I discuss these changes in greater detail later in my testimony.

Q67. Is the Company contemplating any other changes to its Distributed Generation Program?

A67. Yes. If the two proposed changes to Rider 18 summarized above are ordered as proposed, the Company is prepared to voluntarily increase the size of its Distributed Generation Program to 3.0% of the Company's average instate peak load for Full-Service customers during the previous 5 calendar years. I describe this potential change in greater detail later in my testimony.

<u>Distributed Generation Program – Outflow Credit</u>

Q68. Can you please describe the current structure of the Rider 18 outflow credit?

A68. As discussed above, the current Rider 18 outflow credit is equal to retail Power Supply rates less retail-equivalent Transmission rates based on the customer's underlying rate schedule. In effect, the outflow credit is set equal to the total of the Capacity and Non-Capacity portions of Power Supply, less the embedded Transmission component.

Q69. Does the current Rider 18 outflow credit structure value outflowed energy consistently?

A69. No. Basing the outflow credit on retail rates introduces significant inconsistency in how outflowed energy is valued. For example, take two hypothetical residential customers taking service under Rider 18 – Customer A and Customer B. Customer A's underlying rate is D1 (Residential Service Rate - Base) and Customer B's underlying rate is D1.2 (Residential Service Rate – Enhanced TOU). As both D1 and D1.2 are available to all residential customers, it is possible that Customer A and Customer B are located nearby to one another, potentially on the same circuit, sharing much of the same equipment.

If both customers were to outflow 1 kWh of energy between 2-3pm during a summer weekday, they would receive the following compensation for that outflow[1]:

- Customer A: 7.75 cents[2]
- Customer B: 15.33 cents

Despite outflowing the exact same amount of energy at the exact same time, Customer B would receive almost twice the credit received by Customer A. Said

[1] Based on approved outflow rates in Case No. U-20561; excludes PSCR factor adjustment
[2] Assumes outflow is not in excess of 17 kWh per day

differently, the Company's customers would be paying nearly twice as much to Customer B than they are to Customer A for the exact same energy. As such, this inconsistency represents a clear deficiency in the current Rider 18 outflow credit structure.

Q70. What should the Rider 18 outflow credit be based on?

A70. The Rider 18 outflow credit should reflect the quantifiable cost impacts, either cost savings or cost increases, realized by the utility associated with that outflow. Basing the credit on quantifiable cost impacts has three key benefits:

- It ensures that changes to costs realized by the utility as a result of the outflow are appropriately passed onto Rider 18 customers. This ensures Rider 18 customers are neither under-compensated nor over-compensated for their outflow.
- It provides flexibility such that as DG deployments increase, if new costs or savings were to be realized by the utility as a result of DG outflow, those costs or savings could be appropriately incorporated into the outflow credit.
- It provides more consistency across the DG Program such that customers are compensated similarly for similar outflow.

Q71. What are the quantifiable cost impacts realized by the utility associated with Rider 18 outflowed energy?

A71. There are two sources of quantifiable cost impacts related to Rider 18 outflow:

- A reduction in energy market purchases. Given the structure of the MISO market, a Rider 18 customer outflowing energy to the grid is effectively

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reducing the need for the Company to make a market purchase for the same volume of energy.

- Avoided line losses. According to the Company's most recent study, there is an average line loss of 9.33% associated with energy delivered from its generation assets to the secondary distribution system[3]. The outflow from a Rider 18 DG system is likely consumed near the source of generation, such as at a neighbor's house. As such, there is likely little line loss associated with the movement of this energy. These avoided line losses represent a quantifiable savings associated with Rider 18 outflow.

Q72. Are customers taking service under Rider 18 providing a capacity service to the Company that should be reflected in the outflow credit?

A72. No. Customers taking service under Rider 18 have no obligation, contractual or otherwise, to provide capacity to the Company. In effect, customers outflow the excess energy generated by their DG system after serving their onsite load at the time of generation. Customers who pair their DG system with an onsite battery may also choose to use the excess energy generated by their DG system to charge their battery to serve future load or to store as backup for use in the event of an outage. As such, there is no expectation nor obligation of total outflows, outflows during a given period, or a portion of DG system capacity dedicated to outflow. A customer could potentially use all of their DG system generation to offset onsite load and outflow nothing to the Company, or instead they may end up outflowing a significant portion of the generation. Customers are free to modify their onsite usage if they desire to better match their onsite generation and outflow less to the Company. As

[3] Sponsored by Company Witness Robinson, Exhibit A-36 Schedule AA-1

such, customers taking service under Rider 18 are not providing a capacity service to the Company.

Q73. How significant are DG outflows compared to overall class loads?

A73. The relatively small number of customers taking service under Rider 18 makes the aggregate outflow small when compared to class loads. In 2020, aggregate outflow from Rider 18 customers accounted for 0.008% of total D1 usage. Even during summer system peak times[4] aggregate outflows from Rider 18 customers accounted for 0.019% of total D1 usage. At these low levels (i.e., less than 1/10,000 of total D1 load; less than 2/10,000 of D1 summer peak load), aggregate outflows do not meaningfully change either actual or forecasted class loads.

Q74. How is DG generation currently accounted for in class load forecasts?

A74. Currently, as described by Company Witness Leuker, the Company forecasts installed DG capacity as well as the total generation expected from those DG installations. The expected generation is netted out of overall class consumption forecasts, to determine the net load forecast. This forecast is used by the Company for allocation purposes.

As DG deployment becomes more significant, the Company will continue to assess the most appropriate way to incorporate DG generation and outflow in its forecasts.

Q75. Are there other assets taking service under an MPSC-approved rate that have similar characteristics to DG systems under Rider 18?

[4] The Company's 4CP peaks generally occur between 2-5pm with 83% of peaks occurring during this time during 2018-2020

A75. Yes. Qualifying Facilities (QFs) taking service under Rider 5 and electing for "Energy Only Sales" exhibit similar characteristics to customers with DG systems taking service under Rider 18.

More specifically, "Energy Only Sales" apply to "customers electing to sell only energy to the Company as the customer determines such energy to be available." This definition applies exactly to customers taking service under Rider 18 as well, as these customers are similarly under no obligation to supply energy to the Company and determine themselves when energy is available.

Q76. How are customers taking service under Rider 5 and electing for "Energy Only Sales" compensated for energy provided to the Company?

A76. Customers taking service under Rider 5 are provided no Capacity credit for the energy they provide to the Company. Instead, the energy they provide is credited at the day-ahead MISO hourly LMP for the DTE Electric appropriate load node. In effect, customers taking service under Rider 5 are receiving a market-based price for the energy they provide.

Q77. Given these considerations, is it appropriate to include the Capacity portion of Power Supply in the Rider 18 outflow credit?

A77. No. As described above, customers taking service under Rider 18 are under no obligation to provide capacity and are therefore not providing a capacity service. In effect, the rest of the Company's customers are currently paying Rider 18 customers for a service that they are not receiving.

In addition, continuing to include the Capacity portion of Power Supply in the Rider 18 outflow credit represents a clear conflict with the “Energy Only Sales” provision of Rider 5. Rider 5 properly reflects that a Capacity payment is inappropriate in cases where the customer is under no obligation to provide capacity to the Company. Paying Rider 18 customers for capacity represents a clear overpayment to customers taking service under this rider.

Q78. Is it appropriate to include the Non-Capacity portion of Power Supply in the outflow credit?

A78. No. As described above, the Rider 18 outflow credit should reflect the cost impacts, either increases or decreases, realized by the Company associated with the outflowed energy. The Non-Capacity portion of Power Supply does not accurately reflect these cost impacts. As described above a market-based price is the appropriate basis on which to compensate Rider 18 customers for outflowed energy.

Q79. Is it appropriate to include a credit for avoided line losses in the Rider 18 outflow credit?

A79. Yes. As described above, there is likely little line loss associated with DG outflow given this outflow is generally consumed relatively close to the point of generation. This presumably avoids the line losses experienced by the Company for energy it generates itself and delivers to customers. For secondary distribution customers, these line losses are calculated at 9.33%[5]. In other words, 1.000 kWh of energy outflowed from a Rider 18 customer effectively displaces 1.103 kWh of energy that would have been generated and sent by the Company.

[5] Sponsored by Company Witness Robinson, Exhibit A-36 Schedule AA-1

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With that said, including a credit for avoided line loss would only be appropriate if the other changes to Rider 18 are ordered as proposed. As described above, Rider 18 customers are currently already being overcompensated for their outflow, so incorporating a line loss credit into the current structure would only increase this overpayment. Only if Rider 18 outflow compensation is ordered to be based on quantifiable utility cost impacts as described above would a credit for avoided line losses be appropriate.

Q80. Given these considerations, what is the Company's proposal for the Rider 18 outflow credit?

A80. The Company is proposing to set the Rider 18 outflow credit based on the average monthly MISO hourly LMP for the DTE Electric appropriate load node. The outflow credit rate would be calculated and applied separately for each pricing period for customers taking service on TOU rates.

In addition, the Company is proposing to credit Rider 18 customers for the avoided line losses associated with their outflow. For residential Rider 18 customers on the secondary distribution system, this would effectively mean they would be compensated for 1.103 kWh of energy for every 1.000 kWh they outflow.

This proposal best reflects the cost impacts realized by the utility from Rider 18 outflow and corrects the overpayment currently being made to Rider 18 customers for the Capacity portion of Power Supply. Furthermore, it corrects the inconsistencies inherent in the current Rider 18 structure and properly aligns the

Rider 18 outflow credit with the "Energy Only Sales" provision of Rider 5 in two key ways:

- Both would appropriately value outflow energy based on the market rate at the time of outflow
- Neither Rider 5 nor the Company's proposal for the Rider 18 outflow credit provide a payment for the Capacity portion of Power Supply

<u>Distributed Generation Program – Delivery Cost Recovery</u>

Q81. What are the main drivers of Delivery costs?

A81. As discussed previously in my testimony, there are two main drivers of Delivery costs. First, Delivery costs are driven by the number of customers being served by the Company. Second, Delivery costs are driven by the NCP demand of customers or groups of customers.

Q82. Do customers installing a DG system and taking service under Rider 18 drive any cost savings related to Delivery?

A82. No. As it relates to the number of customers being served, clearly a customer installing a DG system and taking service under Rider 18 does not change the number of customers being served by the Company.

As it relates to NCP demand, the Company analyzed the aggregated usage of 342 customers that began taking service under Rider 18 at some point in 2019 and took D1 service in 2018 before installing their DG system. In other words, the Company assessed customers that did not have a system installed for any part of 2018 but did have a DG system installed for all of 2020. The Company compared these customers' average monthly NCP demand in 2018 before they installed their DG systems with their average monthly NCP demand in 2020 after they had installed their systems. The Company checked to make sure that these customers had adequate billing history during 2018-2020 to complete a robust comparison. The Company did a similar comparison for non-Rider 18, D1 customers during the same period to ensure there were not structural differences between Rider 18 and non-Rider 18, D1 customers. The results of the analysis are summarized below in Figure 6.

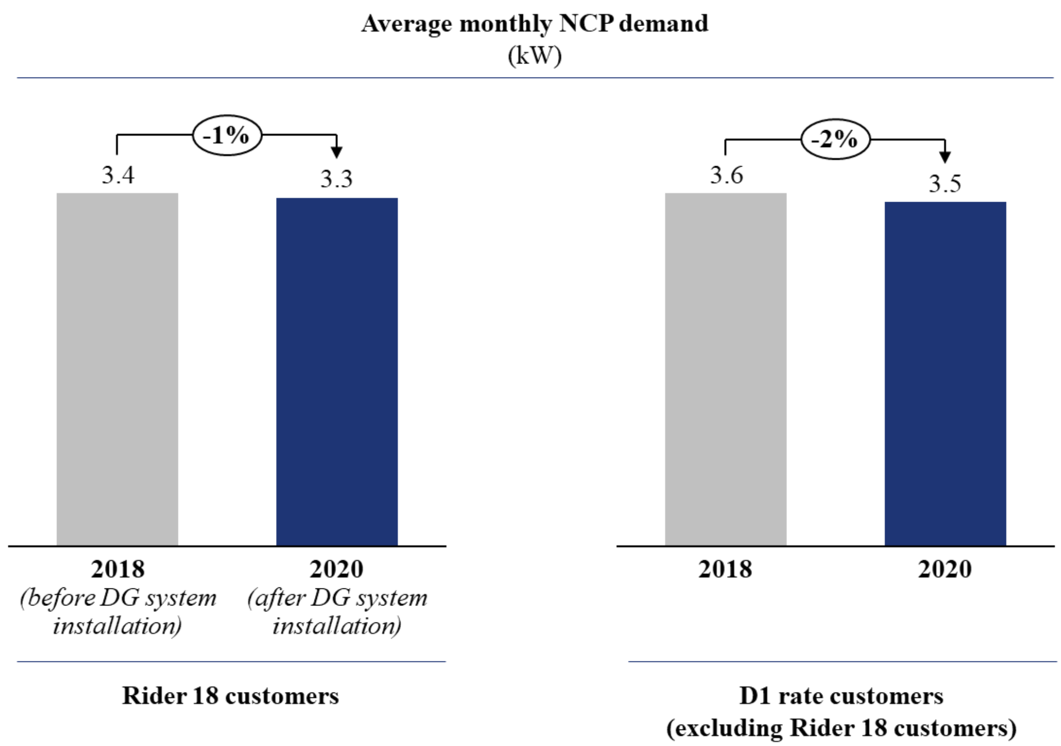

Figure 6: comparison of average monthly NCP demand

The results of this analysis show that customers who installed their DG system and took service under Rider 18 did not meaningfully reduce their average monthly NCP demand. The very slight decrease in average monthly NCP demand realized by

Rider 18 customers (i.e., 1% decrease) was actually less of a decrease than that realized by non-Rider 18 customers during the same period (i.e., 2% decrease).

Given that customers installing a DG system and taking service under Rider 18 do not reduce the number of customers being served by the Company or their average NCP demand, it is also clear that these customers are not driving any Delivery cost savings.

Q83. Are customers installing DG systems and taking service under Rider 18 able to reduce the Delivery portion of their monthly bill?

A83. Yes. Traditional recovery of Delivery costs for residential customers utilizes a "flat" per kWh charge coupled with a fixed monthly charge. When a customer installs a DG system, they typically consume a portion of their generation onsite, thereby reducing the volume of energy they purchase from the utility. As such, customers are able to reduce the Delivery portion of their bill given the volumetric nature of recovery.

By looking at the change in inflow for the 342 customers that installed a DG sometime during 2019, the Company calculates that on average Rider 18 customers are able to reduce the Delivery portion of their bill by $19.66 per month compared to what they would have paid based on their usage without a DG system.

Q84. Given these dynamics, what can you conclude about Delivery cost recovery for Rider 18 customers.

A84. Since Rider 18 customers do not drive any cost savings related to the distribution system, but are able to reduce their own bill, there exists a clear cost shift associated with Delivery costs that is borne by non-Rider 18 customers.

Q85. How is the Company proposing to address this cost shift?

A85. As stated previously, the most appropriate way to recover Delivery costs is through a combination of fixed monthly charges and demand-based charges. As such, the Company believes the most appropriate path forward to correct the Delivery cost shift described above is to move toward this rate structure. More specifically, the Company is proposing that all residential customers taking service under Rider 18 be required to also take service under the Company's proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate that was described previously in my testimony.

The proposed D1.12 rate appropriately charges customers based on the peak demand they are placing on the system. If a customer installing a DG system and taking service under Rider 18 can reduce the peak demand they are placing on the system, then their bill will be rightfully reduced over time as they move to a lower service level. This structure ensures that Rider 18 customers are contributing an equitable amount toward system costs based on their usage.

Q86. Why is the Company not proposing requiring all customers to take service under D1.12?

A86. As discussed previously, the Company believes incrementalism is a critical consideration when contemplating the introduction of new rates or rate design changes. As discussed earlier in my testimony, residential customers will already be subject to the Company's proposed TOU Full Implementation. The Company does not consider it appropriate to require all residential customers to also take service under a demand-based rate at this time. Customers wishing to take service under D1.12 would be free to do so.

With that said, the clear presence of a Delivery cost shift described above being paid for by non-Rider 18 customers compels the Company to propose an immediate solution for Rider 18 customers.

Q87. Has the Company prepared a tariff reflecting the changes described above?

A87. Yes. I have directed Company Witness Willis to prepare a proposed Rider 18 that reflects the changes discussed above.

Q88. Is the Company proposing any type of phase-in or grandfathering approach to the proposed changes to Rider 18?

A88. The Company proposes that the changes to Rider 18 described in my testimony not take effect until the later of either the Company hitting any of the category-specific reservations established through MCL 460.1173(3) (i.e., 0.5% for Category 1 customers, 0.25% for Category 2 customers, or 0.25% for Category 3 customers)[6], or the first quarter of 2024. An effective date so far into the future has several benefits:

[6] If the proposed changes are triggered by the Company hitting any category-specific reservation established in statute, the Company will implement changes to Rider 18 within 90 days of formally notifying the Commission that the reservation limit(s) has been achieved.

- Provides adequate time for current Rider 18 customers, potential Rider 18 customers, and other interested stakeholders to prepare for the changes.
- Eliminates any customer confusion that might otherwise be present if changes to Rider 18 were made at the same time as the Company's TOU Full Implementation.
- Allows the Company to dedicate adequate resources and focus to its TOU Full Implementation.

At the later of either the Company hitting any of the category-specific reservations established through MCL 460.1173(3) or the first quarter of 2024, the Company proposes that these changes become immediately effective for all customers taking new service under Rider 18. At that time, all new Rider 18 residential customers will be required to take service under D1.12 and their DG installation, and Rider 18, must be associated with their D1.12 service. All existing Rider 18 customers will be subject to the updated outflow compensation but may remain on their existing rates(s). Given the issues in the design of the current Rider 18 described earlier in my testimony, the Company is not proposing any grandfathering of existing Rider 18 customers beyond the scope and effective date described above.

<u>Distributed Generation Program – Program Size</u>

Q89. Is the Company prepared to make changes to the size of the Distributed Generation Program?

A89. Yes, if the two changes to Rider 18 discussed above and captured in the proposed Rider 18 tariff are ordered by the Commission as proposed, the Company is prepared to <u>voluntarily</u> increase the Distributed Generation Program size to 3.0% of the

Company’s average instate peak load for Full-Service customers during the previous 5 calendar years. As part of this voluntary increase, the Company would not enforce category-specific capacity limits or reservations beyond the minimum level of participation reserved for each category as authorized in MCL 460.1173(3). The proposed language defining the new Distributed Generation Program size would read:

> *“The Distributed Generation Program is voluntary and available on a first come, first served basis for new customer participants or existing customer participants increasing their aggregate generation. The combined net metering (Rider 16) and Distributed Generation Program (Rider 18) size is equal to 3.0% of the Company's average instate peak load for Full-Service customers during the previous 5 calendar years. Within the Program capacity, 0.5% is reserved for Category 1 Distributed Generation customers, 0.25% is reserved for Category 2 Distributed Generation customers and 0.25% is reserved for Category 3 Distributed Generation customers. The Company shall notify the Commission upon the Program reaching capacity in any Category.”*

Once again, the Company is only prepared to make this voluntary increase if the two changes to Rider 18 summarized above are approved as proposed. Absent an order approving the two changes as proposed, the Company may elect to retain the current Distributed Generation Program size as prescribed in legislation (i.e., 1.0% of the Company’s average instate peak load for Full-Service customers during the previous 5 calendar years) or increase the Distributed Generation Program size to a level different than described above.

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Q90. Can the Commission order the Company to increase the size of its Distributed Generation Program above what was outlined in MCL 460.1173(3)?

A90. While I am not an attorney and I am not offering a legal analysis, my understanding is the Commission cannot order the Company to increase the size of its DG program above what is outlined in MCL 460.1173(3). Any required increase to the program size would likewise require an amendment to MCL 460.1173(3) which either explicitly increases the program size to a specified level, or grants authority to the Commission to set the program size.

However, the Company is free to voluntarily increase the size of its Distributed Generation Program above what is required in MCL 460.1173(3), as Consumers Energy elected to do in 2021.

Q91. Why has the Company not yet voluntarily increased the size of its Distributed Generation Program?

A91. The Company has not increased the size of its Distributed Generation Program because it continues to be concerned about the underlying design of Rider 18. As I've laid out in my testimony, the Company believes that:

- The current Rider 18 rate design treats outflow inconsistently and overcompensates customers for their outflow by including the Capacity portion of Power Supply in the outflow credit, and by not incorporating a market-based mechanism for the remaining credit.

- There is a clear cost shift whereby DG customers can reduce the Delivery portion of their bill without the Company being able to realize a similar cost savings.

The costs associated with these issues are ultimately borne by non-Rider 18 customers in the form of upward rate pressure. As such, it would be inappropriate to increase the size of the Distributed Generation Program as this would allow these issues to grow in magnitude along with the upward rate pressure on non-participants.

With that said, the Company appreciates that various stakeholders value certainty in this space and is therefore prepared to voluntarily increase the size of its Distributed Generation Program if the issues outlined above are sufficiently addressed. The proposals I've described here and which are incorporated in the proposed Rider 18 tariff sufficiently address these issues.

Q92. Why does the size of the Company's Distributed Generation Program need to be limited if the Company's proposals are approved?

A92. Despite the growth of DG installations in the Company's service territory, the total level of installed DG capacity is still relatively low. As such, the long-term impacts of higher levels of DG penetration on the Company's costs and ability to provide safe and reliable power are difficult to predict with any accuracy.

Maintaining a limit on the size of the Company's Distributed Generation Program provides a useful and transparent opportunity to evaluate the program and associated rate design and determine if any adjustments are appropriate.

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Q93. Does this complete your direct testimony?

A93. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHANNEN M. HARTWICK

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHANNEN M. HARTWICK

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Shannen M. Hartwick (she/her/hers), Director of Tree Trim, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I graduated from the University of Michigan with a Bachelor of Science in Engineering in 2007. I am currently in the Executive MBA program with the Ross School of Business at the University of Michigan. I plan to complete this program in 2023.

Q4. What is your work experience?

A4. I began my career with DTE Electric in 2008 and have been employed there since. I started out as an Associate Engineer in the Performance Management group where I worked on several process improvement projects across Distribution Operations. Over the years, I held a number of positions with increasing leadership responsibilities primarily within Distribution Operations and spent a year in DTE Electric's strategy team. Within Distribution Operations I worked in areas that include: Process Management Team, Substations, Asset Optimization (SOC, Strategy, and dispatch), Southeast Service Operations and Tree Trim.

In 2014, I took a position as a Developmental Field Supervisor – Southeast Service Operations where I was responsible for leading the frontline lineman performing maintenance, operations, and construction on DTE Electric's electrical distribution system.

In 2015, I was promoted to Manager – Tree Trim where I was responsible for leading Operations for the Tree Trim Team, comprised of DTE Energy Employees and all six of our tree trim vendors (comprising over 1200 employees in 2020). In this role, I was responsible for safety, quality, productivity, customer satisfaction, storm and trouble restoration efforts, and relationships with municipalities.

Q5. What are your current job responsibilities?

A5. Currently, I am the Director of Tree Trim. In this role, I am responsible for the strategy and execution of the Enhanced Tree Trim Program. This includes contract negotiations, strategy, planning, auditing, execution, outage restoration trimming, customer satisfaction, tree trim technology, and scheduling.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. I have not previously sponsored testimony, however, I supported the preparation of testimony on the topic of the Company's tree trimming program in previous rate cases (Case Nos. U-20162 and U-20561).

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Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to:

- Discuss the importance of DTE Electric's vegetation management ("Tree Trimming") program;
- Support the historical Operations and Maintenance (O&M) expenses related to tree trimming efforts for 2019 and 2020 and the projected base O&M expenses and the Tree Trim Regulatory Asset Surge funding amount for November 1, 2022 to October 31, 2023;
- Request approval of the Surge Program funding for 2023-2024;
- Provide details related to the Company's Tree Trimming Surge Program that will deliver on the reliability goals established in the Company's Distributed Grid Plan
- Describe the customer benefits of the Company's expanded Tree Trimming Surge Program to date.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-13	C5.6.1	Projected Tree Trim Expenses
A-22	L1	Projected Value of Tree Trimming Surge Program
A-31	V1	2020 Tree Trim Annual Report

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were, except for Exhibit A-22, Schedule L1 which I am co-sponsoring with Witness Vangilder. In this instance, only pages one and two were prepared by me or under my direction.

Outline of Testimony

Q10. How is your testimony organized?

A10. My testimony is organized as follows:

- Progress of the Company's Tree Trimming Program/Measuring Work Volume
- Enhanced Tree Trimming Program Results
- Tree Trimming Program Improvements
- Continued Need for the Tree Trimming Surge Program
- Tree Trimming Surge Plan Execution
- Benefits of the Tree Trimming Surge Program
- Funding Required
- Spot Tree Trimming
- Tree Trimming Surge Funding Mechanism
- Resourcing the Tree Trimming Surge
- Herbicide Program
- Measuring Progress
- Conclusion

Progress of the Company's Tree Trimming Program/Measuring Work Volume

Q11. What is the Company's Tree Trimming Program?

A11. The Company has an ongoing Tree Trimming Program to address interference between vegetation and electric distribution facilities. The objectives of the program are to reduce tree-related safety hazards and to reduce the volume of tree-related trouble cases thereby increasing customer reliability. The Company's Tree Trimming Program, which is based on industry best practices and the Company's experience, is known as the Enhanced Tree Trimming Program ("ETTP"). The ETTP was described in detail in testimony in the Company's last four rate cases: Case Nos. U-18014, U-18255, U-20162, and U-20561.

Q12. Was the MPSC supportive of ETTP in Case No. U-20162?

A12. Yes. The Commission approved the first three years of the Tree Trimming Surge Program as requested by the Company. The Commission indicated that it would reevaluate the remainder of the Surge funding at a future date. In the final order the Commission noted:

> *The Commission reiterates its desire for a safe and reliable electric system as stated on pp. 43-44 of the April 2018 order regarding the ETTP program. The record shows that DTE Electric has continued to bring tree trimming spending into line with the approved amounts, and the Commission agrees that falling behind in this area will cost more in the future and perpetuate reliability challenges. The record also shows direct, quantifiable benefits in terms of reliability improvements resulting from the ETTP program. 3 Tr 200-206. [MPSC Case No. U-20162, May 2, 2019 Order, p 79*

Q13. Did the MPSC continue to support the Surge program in Case No. U-20561?

A13. Yes. The Commission approved an additional year of Surge funding for calendar year 2022.

Q14. Does DTE Electric break its territory down into zones for ETTP purposes?

A14. Yes. There are three circuit zones.

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Q15. How does the ETTP define tree work to be performed based on circuit zones?

A15. In the right-of-way of all zones, the Company attempts to remove all small trees and larger trees that pose an unacceptable risk to the electrical system. Additionally, the Company attempts to mitigate all hazard trees (trees outside the right of way that are dead, diseased, or dying and threaten to interrupt service to customers).

Specifically, in Zone 1, the portion of the circuit from the substation to the first protective device or drop down, the Company removes all branches overhanging the conductors. In Zone 2, the portion of the circuit from the first protective device or drop down to the fused lateral, and Zone 3, the fused laterals, the Company removes all softwood and hardwood branches overhanging the conductors at less than a forty-five-degree angle.

Q16. What were the results of the Tree Trimming Program in 2020?

A16. The 2020 results will be described in terms of miles trimmed, units completed, cost to achieve, reliability impact, and customer satisfaction.

(i) Miles Trimmed: The Company trimmed 5,589 line miles on 814 separate circuits exceeding its plan of 5,500 miles.

(ii) Units Completed: The Company completed 25,557 tree trim comparable units compared to a target of 25,319. I discuss this more later in my testimony.

(iii) Costs to Achieve: DTE Electric spent $151.1 million on the tree trimming program in 2020. This equates to $16.5 million more than the $134.6 million[1] of funding approved in MPSC Cases No. U-20561 and No. U-20162.

[1] $91.3 million for base tree trim funding plus $43.3 million for Surge deferral funding

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(iv) Reliability Impact: Circuits trimmed as part of the ETTP since 2015 show an average annual reduction of 69 percent in the number of tree-related customer interruptions[2] and an average annual reduction of approximately 62 percent in the number of customer minutes of interruption[3] in the year following trimming, compared to the non-ETTP circuits. These results are discussed in more detail later in my testimony and in the Company's annual Tree Trim Report for 2020, submitted in March 1st, 2021, which we have included as Exhibit A-31 Schedule V1.

(v) Customer Satisfaction: An important measure of customer satisfaction is the number of MPSC complaints filed each year related to the Company's tree trimming work. Although the complaints for tree-related service issues increased slightly to 47 YTD in 2021 complaints compared to 43 for the same timeframe in 2020, of the complaints were primarily driven by customers asking for tree trimming. The complaints have not been driven by customer concerns regarding the tree trimming work conducted on their properties; rather, they demonstrate customers' support for tree trimming and its positive impacts on reliability and costs.

Q17. Is measuring miles trimmed the best way to measure tree trim progress?

A17. Miles trimmed is a valuable way to measure progress and understand the work, but each mile can vary significantly and counting miles is not the only measure of the actual work performed. DTE Electric uses "comparable units" to more accurately measure tree-trim work performed. Comparable units consider the work volume and the complexity of the work on the circuit to provide a clearer picture of the true

[2,3] Weighted average of circuits trimmed from 2015 to 2019

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scope of work on each circuit and allow us to balance the work more evenly among contractors and regions. The Company is continuing to improve this concept and is actively using comparable units as one of our standard measures of tree trim progress.

Q18. How does the Company define work volume?

A18. Work volume is defined by tree density. The more trees that need to be trimmed or removed per mile, the higher the volume. The Company has circuits that range from less than 10 trees per mile to circuits with more than 1,000 trees per mile.

Q19. How does the Company measure density?

A19. We use a combination of actual data from circuits that have been recently cut and a density study that was completed in 2018 by Environmental Consultants Inc. (ECI), a nationally recognized expert in utility vegetation management that has been contracted by DTE Electric since 2015. The density study looked at the majority of DTE Electric circuits and sampled every 10th span to give us an approximate density. Any circuit that did not have data from actuals or the density study is assigned the service center average density. The density values will continue to be updated as we get more accurate data from the field.

Q20. How does the Company define work complexity?

A20. Work complexity is a measure of many factors that influence the cost to perform work in a given area. These factors include:

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(1) Back lot work – The majority of DTE Electric's distribution circuit miles are in the back of residences. These portions of the circuit are often inaccessible by bucket truck and require tree trimmers to climb the tree to perform trimming.

(2) Security – There are some areas that require our crews to work with assistance from a security contractor, increasing the cost to perform work. For example, in 2019, while working in the Detroit area, the tree crews had over 16 chainsaws and 3 blowers stolen out of their locked trucks over 5 different occasions, resulting in over $20,000 in losses.

(3) Off cycle work – The farther off cycle the work the more expensive it becomes. Not only does the volume of wood removed increase with each growing season but often the trees grow into and through the distribution lines. In these situations, overhead line crews are needed to perform a circuit shutdown before work can be completed.

(4) Customer Outreach – While DTE Electric provides equal service to all customers, we tailor outreach efforts based on community feedback. As such, certain areas within our service territory are more interested in the tree work we are performing within their communities and require more customer contact and outreach efforts before work can begin.

Q21. How does the Company measure work complexity?

A21. Complexity is a more complicated measure than density due to the variety of factors that can influence it. To approximate complexity, we indexed the average service center cost to trim a tree and used it as the complexity factor. For example, our North Area Service Center has the lowest average cost per tree and is indexed to 1.0 complexity factor. All other service centers have higher average per tree costs

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and, as such, have higher complexity factors. Where we have actual cost or bid data, we are using that data to determine a more accurate complexity factor. We will continue to refine complexity and we expect that it will get increasingly more precise over time.

Q22. How does the Company use density and complexity to measure work volume?

A22. We multiply circuit density per mile by the complexity factor and divide by 100 for scaling purposes. Without the use of a scaling factor, the units would be very small in terms of work volume. This calculation yields a "comparable unit" per mile estimate to more accurately gauge true work volume. For example, if Circuit A had 1 unit per mile and Circuit B had 2 units per mile then, assuming the circuits are the same length, we would expect Circuit B to cost twice as much and take twice as much time to complete. Table 1 below gives examples of how units were calculated on three DTE Electric circuits.

Table 1 Unit Calculation Example

Service Center	Circuit	Density Per Mile		Complexity Factor		Scaling Factor		Comparable Units Per Mile
Caniff	GDRIV1115	240	x	3.1	÷	100	=	7.44
Western Wayne	ALPHA9198	125	x	2.3	÷	100	=	2.88
Newport	ACME9499	36	x	2.0	÷	100	=	0.72

Q23. Do you have additional examples that highlight the difference in density and complexity?

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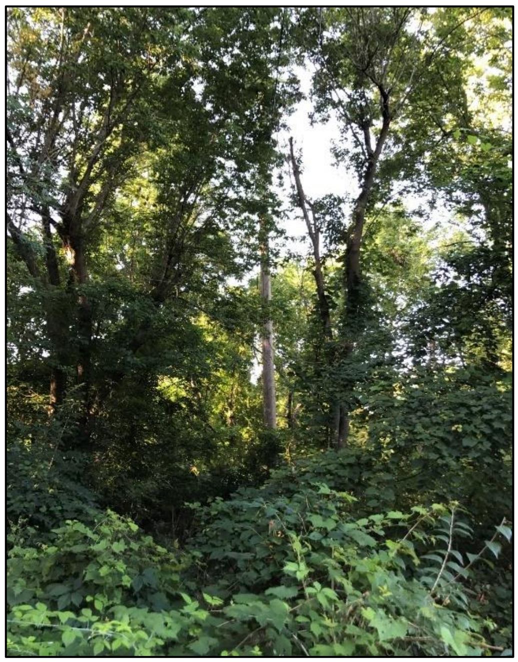
A23. Yes. Image 1 below shows an ASPEN circuit with low density and low complexity. As can be clearly seen, there are very few trees by the line (seen in the distance). Additionally, the work is right on the road making it very easy to get equipment to the work site. Image 2 is a high density PLYMO (Plymouth) circuit with high work complexity. The work has many more trees per mile and, while it can't be seen in the picture, the work is in backyards, which requires labor intensive climbing work and limits the use of equipment to complete the work.

Image 1 – ASPEN Substation

Image 2 – PLYMO Substation



Q24. How did the Company perform in 2020 in terms of comparable units?

A24. As shown in Table 2 DTE Electric completed 101% of its comparable unit work target.

Line No.

Table 2 Tree Trimming Mileage and Comparable Units

2020	Miles	Comparable Units
Actual	5,589	25,557
Target	5,500	25,319
% of Target Achieved	102%	101%

Q25. How many miles and comparable units did the Company anticipate trimming in 2021?

A25. The Company plans to trim 6,156 miles and 23,524 units in 2021. This is 567 more miles than were trimmed in 2020.

Table 3 Tree Trimming Mileage

	Annual Plan Miles Completed / Planned	% of System (miles)	Annual Plan Units Completed / Planned	% of System (units
2020 Actual	5,589	18%	25,557	21%
2021 Plan	6,156	20%	23,524	19%

Q26. In Case No. U-20561 the Company testified it would trim 6,455 miles in 2021 with Surge funding. Can you explain why your plan is to now trim 6,156 miles?

A26. Yes. The model used in Case No. U-20561 and updated for this instant rate case is built on an average mile (average density, average complexity, and therefore average units). When we develop specific plans for each year the Company prioritizes circuits based on reliability and wire down reduction. Frequent outage circuits generally have a high unit density when compared to the DTE Electric system average. Completing high unit density circuits at the start of the Surge results in fewer miles trimmed but the same amount of work completed.

Q27. Does the Company expect to achieve the 2021 target?

A27. No. Through November 12, 2021, DTE Electric has cut 4,881 miles, currently projecting to complete approximately 5,700 miles. We are projecting several reasons for the Company missing the year-end target this year:

- Unprecedented summer storms – The frequency and intensity of storms in 2021 was greater than prior years. During the storms tree crews are prioritized to help restore outages and minimal maintenance trimming is completed during this time. While we began the summer ahead of our miles target, we slowly lost the lead over the course of July and August.
- Unfavorable fall weather – Fall is usually one of the most productive times for maintenance trimming. The cooler weather and fewer storms keep crews on maintenance work. Further, as leaves fall from the trees and the ground firms for the winter, crews can be more productive. Unfortunately, this fall we had three-times the number of storm days and twice as many inclement weather days as we projected for August to October.
- Focusing resources in the communities and circuits most impacted by the storms this summer. These areas are harder, denser miles relative to other areas of the territory; therefore, trimming these area yields fewer miles, but the Company has committed to prioritizing these miles.

Q28. Can you provide additional detail on how the 2020 and 2021 circuits were prioritized for trimming?

A28. Yes. In 2019, the Company finalized a multiyear optimization of circuits for the Surge program that included selections for 2020 and 2021. The optimization considered multiple factors including wire downs, reliability, and trim cost. The model output was then adjusted to balance comparable units, account for location of trimmer resources, and prioritize customer circuits with higher outages or wire downs. In 2021, the prioritization includes ensuring circuits that have previously been trimmed to ETTP in 2016 will be on the plan to keep them on a 5-year trim cycle.

In response to the severe storms this summer, the Company has allocated additional funding to the Tree Trimming program for 2021. The miles added to the plan with this funding focus on the communities and circuits most impacted by the storms this summer. All of these circuits added were off-cycle and part of the 2022 plan, therefore, pulling these circuits ahead helps to continue to bring the full system on-cycle as soon as possible. While the Company anticipates falling short of our overall miles target, we are prioritizing completing trimming on these circuits.

Q29. How many miles have been trimmed to the ETTP standard within the City of Detroit prior to 2021 compared to what is expected to be trimmed by the end of 2021?

A29. Prior to 2021, the Company trimmed 1,896 miles to the ETTP standard in the City of Detroit. In 2021, DTE Electric is trimming miles in Detroit with a plan to trim 529 miles. Results are highlighted in Table 4 below. By the end of 2021, 89% of the City of Detroit line miles will have been trimmed to the ETTP standard compared to 70% of the overall system.

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Table 4 City of Detroit ETTP Miles

	Trimmed to ETTP Standard through 2020	Trimmed to ETTP Standard by end of 2021
2021 ETTP Miles	386	529
All ETTP Miles Trimmed	1,896	2,216
Total Detroit Miles[1]	2,500	2,500
All ETTP Miles Percentage of Detroit Complete	74%	89%
All ETTP Miles Percentage of System Complete	60%	70%

(1) Includes circuits that cross into or out of Detroit. Detroit only miles are approximately 2400 but miles are counted by circuit, not municipality.

Enhanced Tree Trimming Program Results

Q30. What methodology was used to calculate the ETTP performance?

A30. The Company continues to use the same methodology outlined in Case No. U-20561 as well as in the March 1, 2021 Tree Trim Annual Report submitted in the Case No. U-20162 docket. The March 1, 2021 Tree Trim Annual Report has been submitted as Exhibit A – 31, Schedule V1 for reference. The report, and results mirrored below, include outage and event data through the end of the 2020 calendar year.

Q31. What has been the improvement in outage events on circuits trimmed to the ETTP compared to the non ETTP control group?

A31. The actual difference of outage events on ETTP circuits compared to the balance of the system not trimmed ETTP is 76.1% in post-trim year 1, 93.5% in the second year, 87.0% in the third year, and 91.2% in the fourth year. The actual reduction for Years 1-4 post ETTP trim are depicted in Table 5.

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Table 5 ETTP Tree-Related Outage Event Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Reduction
1 Year Post Trim	1,071	-34.0%	42.1%	**-76.1%**	-57.0%
2 Years Post Trim	642	-25.7%	67.8%	**-93.5%**	-57.0%
3 Years Post Trim	321	-13.8%	73.2%	**-87.0%**	-50.0%
4 Years Post Trim	193	-6.3%	84.9%	**-91.2%**	-37.0%

Q32. How does this reduction compare to results under the prior trimming practice?

A32. As discussed in Case No. U-20162, (3T 202) the past practice of trimming a "clearance circle" around conductors provided only a 13% reduction in tree-related events in the year following trimming as compared to the average number of events in the three-years preceding trimming.

Q33. Do you see similar differences for customer interruptions and the number of customer minutes of interruption on ETTP vs. non-ETTP circuits?

A33. Yes. Using the same methodology discussed above, the Company has determined that actual customer interruptions on ETTP circuits vs. Non-ETTP circuits show a

Line No.

62.9% difference in Year 1, 76.4% difference in Year 2, 71.7% difference in Year 3, and 75.0% difference in Year 4. These results are shown in Table 6. Customer minutes of interruption, shown in Table 7, also show significant improvements. Actual minutes of customer interruption on ETTP circuits vs. Non-ETTP circuits show a 57.3% difference in Year 1, 84.9% difference in Year 2, 42.2% difference in Year 3, and 47.9% difference in Year 4.

Table 6 Post ETTP Tree-Related Customer Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Customers Interrupted for ETTP circuits	% Change in Customers Interrupted for Non-ETTP circuits	**Difference in % Change in Customers Interrupted ETTP vs. Non-ETTP circuits**	U-20162 Surge Model Reduction
1 Year Post Trim	1,071	-34.4%	34.8%	**-62.9%**	-57.0%
2 Years Post Trim	642	-19.7%	56.6%	**-76.4%**	-57.0%
3 Years Post Trim	321	-22.1%	49.7%	**-71.7%**	-50.0%
4 Years Post Trim	193	-23.3%	51.7%	**-75.0%**	-37.0%

Table 7 Post ETTP Tree-Related Customer Minutes of Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Customer Minutes Interrupted for ETTP circuits	% Change in Customer Minutes Interrupted for Non-ETTP circuits	**Difference in % Change in Customer Minutes Interrupted ETTP vs. Non-ETTP circuits**	U-20162 Surge Model Reduction
1 Year Post Trim	1,071	-44.6%	12.7%	**-57.3%**	-57.0%
2 Years Post Trim	642	-44.4%	40.4%	**-84.9%**	-57.0%
3 Years Post Trim	321	-53.7%	-11.6%	**-42.2%**	-50.0%
4 Years Post Trim	193	-59.9%	-12.0%	**-47.9%**	-37.0%

Q34. What has been the reduction in wire-down events post-ETTP trimming?

A34. Wire downs on the circuits that have been trimmed as part of the ETTP are significantly lower in the years after trimming compared to Non-ETTP circuits. The Year 1 difference is 32.2%, Year 2 is 42.0%, Year 3 is 37.3% and Year 4 is 43.4%. Reductions are shown in Table 8.

Table 8 Post-ETTP Wire-Down Difference Compared to Non-ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change Wire-Down Events for ETTP circuits	% Change for Wire-Down Events for Non-ETTP circuits	**Difference in % Change in Wire-Down Events ETTP vs. Non-ETTP circuits**
1 Year After Trimming	1,071	-17.6%	14.6%	**-32.2%**
2 Years After Trimming	642	-13.1%	28.8%	**-42.0%**
3 Years After Trimming[4]	321	-13.2%	24.1%	**-37.3%**
4 Years After Trimming[2]	193	-23.3%	20.1%	**-43.4%**

Q35. Of the four metrics shown in Tables 5-8, which one best illustrates the impact of the Tree Trimming Program?

A35. Tree-related outage events and wire down reduction are most closely tied to the effectiveness of the Tree Trimming Program. The Tree Trimming Program has the capability to reduce events and wire downs by trimming and removing trees that threaten the distribution system. Tree-related customer outages are also highly correlated to tree-trim effectiveness but incorporates some degree of randomness based on where the event occurs on the circuit. If the event is on the backbone of the circuit, then more customers are likely to be impacted. Because the majority of

[4] Sample size is relatively small for 3 & 4 years after trimming

tree related minutes are the result of storms, minutes of customer interruption can be more variable because they are impacted by circumstances outside of the control of the tree-trim program including crew availability, travel time to outage, outage prioritization, and accessibility of outage.

Q36. How does the March 2017 wind storm affect the results shown in Tables 5-8?

A36. The effects of the March 2017 windstorm are included in the results shown in Tables 5-8 in Year 1 and Year 2. As discussed in Case No. U-20162, ETTP circuits outperformed Non-ETTP circuits during that windstorm. The 2017 windstorm caused a high number of healthy trees outside of the right-of-way (ROW) to blow over and into our lines. These off-ROW healthy trees are not addressed as part of the ETTP specification and, since the outage cause is still coded as tree, they depress year one results across all metrics shown in 5-8 (wire downs are not assigned a cause code).

Tree Trimming Program Improvements

Q37. What improvements has the Company made to its tree-trim program in the last twenty-four months?

A37. The Company has made several significant improvements to its tree-trim program; some key improvements include:

(1) Long Term Contracts – The Company is in the second year of a 3-year contract with its tree trim vendors. The long-term contract has provided needed financial stability for the vendors and has allowed them to invest in growing the local work force to become less reliant on outsource crews and purchasing additional

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specialty equipment to improve productivity. We will begin our next three-year contract in 2023, which aligns with the final years of the Surge.

(2) Specialty Equipment – The Company is partnering with its tree-trim contractors on new ways to improve productivity using innovative tree-trim equipment. One contractor added a new insulated boom-mounted saw (one of two of its kind in the world) to its fleet, which allows for the use of the saw within the "energized zone" near the wires. These saws, seen in **Image 3** can quickly and safely 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. The Company is also exploring other ways to utilize specialty equipment in back-yard areas where climbing crews are normally required. These include increased use of backyard buckets (**Image 4**), backyard chippers, mowers, and backyard Jarraffs (**Image 5**). Several mowers have been added to the contractors fleet this year, specifically in the northern territory, to increase productivity. These work well in rural areas that are on cycle for trimming, especially for the sub-transmission lines. The Company and a contractor partnered on an experiment to utilize mowers and backyard Jarraffs to clear the alleys in the City of Detroit. An alley after it has been mowed is seen in **Image 6**. These experiments have been successful and key learnings shared with all contractors executing similar work.

Image 3 Insulated Boom-Mounted Saw

Image 4 Backyard Bucket

Line
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Image 5 Jarraff

Image 6 Detroit Alley After Mowing

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(2) Improved Price Accuracy – The Company was successful in utilizing its arborist employees to set up a specialized estimating team to price out circuits before contractor bids are evaluated. The pricing estimates from this team allow us to more accurately determine fair pricing for each circuit/substation during contract negotiations resulting in significant cost savings.

(3) Improved Negotiation Timeline – The Company has adjusted its negotiation timeline and streamlined the process to award contracts each year. The new timeline allows for negotiations to be completed in the fall, which allows for vendors to begin preparing for the next year, including right-sizing their workforce, identifying equipment needs and creating an efficient schedule for the year. Additionally, the Company provides a small selection of circuits that the vendors can begin planning in the fall so that the vendors have planned work they can start trimming first thing in January.

Q38. Are there additional improvements the Company is currently working on related to its tree-trim program?

A38. Yes. The Company is working on several initiatives:

1) Scheduling Improvement Project – The Company has dedicated a team to improve and advance scheduling efforts within Tree Trim. Tree Trim supports the following workstreams: maintenance trimming, trouble trimming, capital trimming and customer requests. Effectively prioritizing and scheduling these workstreams has been disaggregated in years past, often done at the service center-level. The scheduling team is working to develop an integrated scheduling tool that monitors all these workstreams in a centralized format. This will allow the Company to more efficiently schedule tree trimming required for

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customers and capital construction projects, while staying on-schedule for the annual maintenance trimming. The scheduling team has also developed dashboards to track maintenance miles trimmed on a weekly basis and are available to other DTE Electric stakeholders, such as our customer support teams, who use the dashboards to understand when tree trimming is taking place in different communities.

2) Enhanced monitoring of reliability and circuit performance - As a way for the Company to continually improve its Tree Trim program, a considerable amount of time and effort has been put into planning and monitoring the overall success of the program. Most recently these efforts have allowed the Company to develop several new tools and processes to improve the speed of analyses and granularity of data available to assess the reliability performance of ETTP. For example, a new report was developed in PowerBI[5] which compares the reliability performance during any specific period, such as a recent storm, at different levels of granularity, such as the circuit, service center, or city. This tool was especially useful during this summer with the high volume of storms.

3) Light Detection and Ranging (LiDAR) – The Company is continuing to explore the opportunities and benefits of utilizing remote sensing technology such as LiDAR as part of the tree trimming program. LiDAR technology provides advanced data on the Company’s tree density, growth patterns and emerging hot spots. This data could provide significant value to the Tree Trimming program in the form of assisting in scoping and estimating costs for maintenance work, and identity areas where tree encroachment may cause hot spots to emerge.

[5] PowerBI is a software platform to assist in data intelligence and visualizations

Line No.

Continued Need for the Tree Trimming Surge Program

Q39. What is the biggest root cause of outages?

A39. As discussed in the Company's Distribution Grid Plan (U-20147), tree interference remains the leading driver of customer outages. Tree-caused outages account for two-thirds of the time that customers spend without power; thus, the successful execution of the Tree Trimming Program will allow the Company to significantly improve the overall reliability of electric service.

Q40. What is the best way to reduce tree-related outages?

A40. A robust Tree Trimming Program is needed to address system reliability including reduction of outage events, customer interruptions, customer minutes of interruption, wire downs, and other non-outage trouble events. The program must be funded to maintain a tree-trim cycle that permits the subsequent trimming of a circuit before the trees on that circuit grow back into the Company's wires and become hazards.

Q41. What is the Company's vision for its Tree Trimming Program?

A41. The Company remains firmly committed to achieving a five-year cycle.[6] This will be accomplished by continuing to improve the efficiency with which trimming work is executed and by working through the regulatory process to obtain the funding to support the program. As stated by Company Witness Pfeuffer in her testimony regarding the Company's Global Prioritization Model, tree trimming is the highest priority investment. No other program in the Company's portfolio of

[6] The five-year cycle applies to distribution circuits. Sub-transmission circuits require a shorter three-year cycle, which will be discussed below.

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distribution projects will have a greater impact on mitigating risks, improving system and customer reliability, and managing the costs of operating the Company's electric distribution system.

Q42. How many miles need to be trimmed annually to achieve a five-year cycle?

A42. Assuming an average mile, DTE Electric currently needs to trim approximately 6,538 miles per year to achieve the optimal five-year cycle for distribution circuits. As discussed above, miles vary significantly from year to year, so the Company can be above or below the 6,538 mile mark and still be on target for a five-year cycle.

Table 9 Tree-Trimming Cycle Length

	Overhead Miles	**Cycle Length (years)**	**Cycle Mileage (miles / year)**
Distribution Circuits	28,459	5	5,692
Subtransmission Circuits	2,539	3	846
Total	30,998	4.75	6,538

Q43. Why is the Company moving to a five-year cycle?

A43. The Company typically performs trimming within 15 feet on either side of the distribution pole centerline, or approximately 10 feet from the conductors. The Company's target of a five-year cycle is based on the following facts:

(1) Trees near the Company's distribution equipment grow approximately 10 feet on average in five years.

(2) The five-year cycle provides a reasonable and acceptable level of tree-to-conductor contact comparable to the industry standard of 10% - 15%. Tree-to-conductor contact represents the likelihood of any portion of the tree touching the

Line
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conductor. A tree-to-conductor contact level of 10% - 15% denotes the estimated average percentage of trees in contact with the overhead electrical facilities across the entire distribution system when the recommended cycle length and clearance standards are reached.

Q44. How does the Company's targeted cycle length compare to the industry benchmarks?

A44. The Company's targeted five-year cycle on distribution circuits is comparable to the actual industry average of 4.9 years, per the report published by CN Utility Consulting, Inc. (CNUC) - Distribution Utility Vegetation Management Benchmark Survey Results 2016 - as shown in Figure 1. Furthermore, all but six of the participating companies target a cycle of five years or less.

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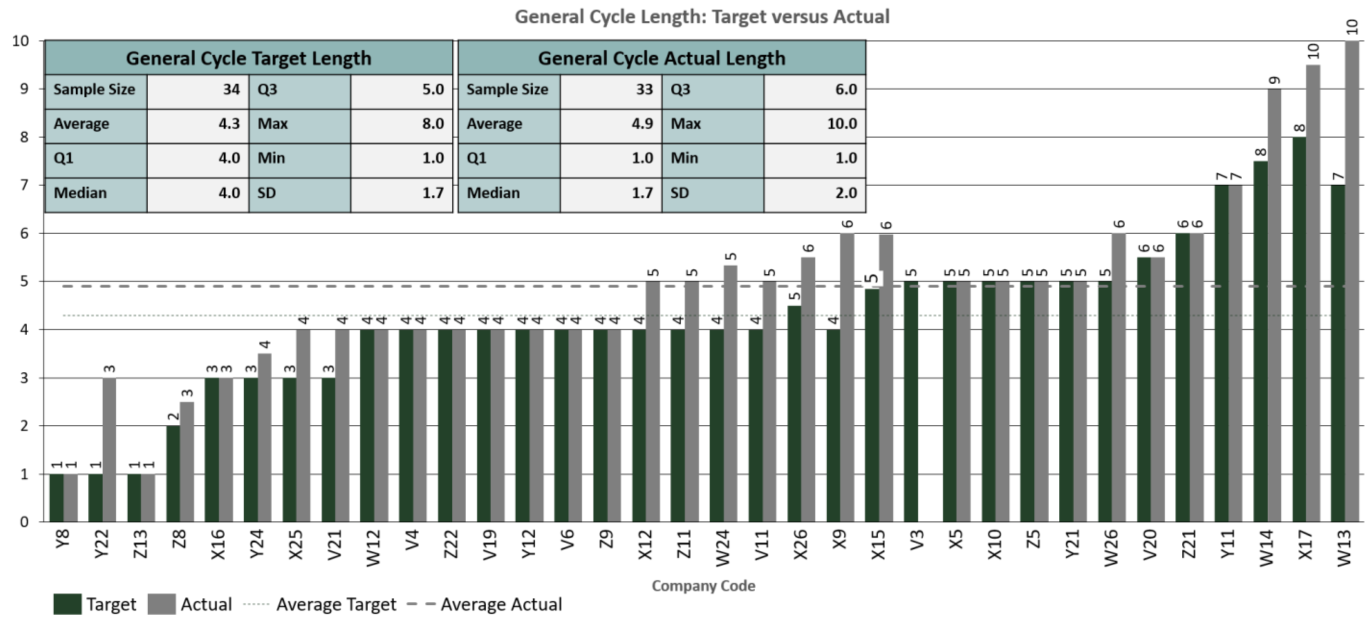
Figure 1 Distribution Utility Vegetation Management Benchmark

Survey Results – Cycle Length: Target vs. Actual



<u>Tree Trimming Surge Program Execution</u>

Q45. When did the Surge Program begin?

A45. The company began the Surge Program in 2019, as a result of the order in Case No. U-20162.

Q46. Have there been changes to the Surge Program?

A46. Yes. On August 31, 2021, the Company proposed a minimum of $70M in funding for the Tree Trim program in ex parte Case no. U-21128. Per the application, the Company will increase its investment in the Tree Trim Surge during the remainder of 2021 through 2023, beyond the authorized regulatory asset amounts, and will not seek recovery of the additional expenditures. This has the effect of advancing the Company's tree trimming efforts while avoiding future customer expense for those investments, thus providing an affordability benefit to customers.

Q47. Does the additional $70M change when the Company is able to complete the Surge plan and achieve a five-year cycle?

A47. The Company is *targeting* to achieve a five-year cycle, and complete the Surge program, by the end of 2024. This is one year earlier than previously proposed in Case Nos. U-20162 and U-20561.

Q48. What is meant by "backlog" and "on-cycle"?

A48. Backlog refers to the circuit miles that have yet to be trimmed as part of the ETTP. On-cycle means that the circuit miles have been trimmed within the last five years to ETTP specification.

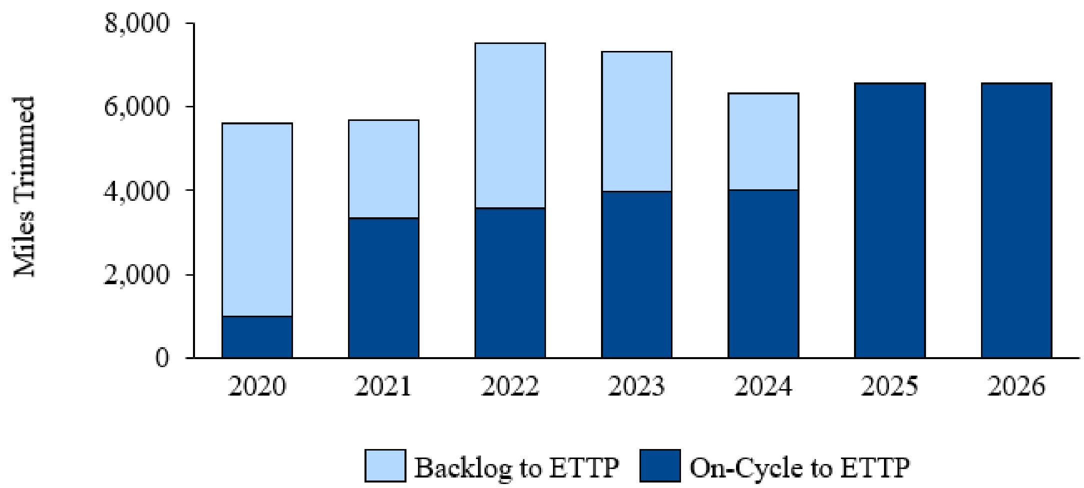
Q49. Will the Company prioritize circuits already trimmed as part of the ETTP before the circuits on the backlog?

A49. Yes. Circuits already trimmed as part of the ETTP will be maintained on a five-year cycle, while also addressing the backlog of circuits that have yet to be trimmed as part of the Company's ETTP.

Q50. How many miles will be addressed annually on the backlog compared to those on-cycle during the Surge?

A50. Figure 2 shows the miles the Company intends to trim from the backlog of circuit miles that have yet to be trimmed as part of the ETTP and the miles that are on-cycle and have been trimmed as part of the ETTP. The tree trimming model submitted in this instant case populates the miles shown in Figure 2.

Figure 2 Miles Trimmed During Surge and Post-Surge



Q51. Are the specifications applied consistently throughout the Surge?

A51. Yes. Tree-trimming specifications are applied consistently throughout the Company's service territory. The Company trims and removes trees to maintain circuit clearance for one five-year cycle worth of growth, which, on average, necessitates ten feet of clearance to the outermost conductor. The required clearance is species-specific. All circuits are audited post trimming to ensure the specifications have been meet. Any deviation from specification is corrected by our contractors at no additional cost to the company.

Q52. Why is a three-year cycle needed on subtransmission circuits?

A52. The three-year cycle is necessary because of the high customer impact of subtransmission lines. A trouble event on a subtransmission circuit can potentially cause an entire substation to lose power, which would affect, on average, over 3,600 customers, while a trouble event on a distribution circuit would affect, on average, approximately 700 customers. Therefore, outage events on subtransmission lines have a severity effect five times greater than a similar outage event on a distribution circuit.

Benefits of the Tree Trimming Surge Program

Q53. How will customers benefit from reducing the tree-trimming cycle length to the industry benchmark of a five-year cycle?

A53. Reducing the tree-trimming cycle length to five years will provide tree-related benefits and savings in multiple ways:

(1) Fewer wire-down events, resulting in improved safety,

(2) Fewer outage and non-outage events, leading to improved reliability and a positive impact on reactive O&M and capital costs; this will also allow for the re-allocation of resources to other necessary work across the Company's distribution system,

(3) Lower customer complaints. The Company recognizes and acknowledges that tree-related outage and non-outage events are a major issue for our customers that can be rectified through the tree-trim program and requested funding,

(4) Lower future trimming costs as the number of trees growing within the right-of-way are trimmed or removed more frequently, resulting in the need to remove less wood from the trees near the Company's lines, and

(5) Lower customer costs as tree-related outages are reduced (improved reliability will reduce downtime for customers' manufacturing processes, allow

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commercial businesses to remain open, and reduce the inconveniences that residential customers experience).

Q54. How much value does the program provide to customers?

A54. The net present value (NPV) analysis, which is supported by Witness Vangilder, is shown in Exhibit A-22, Schedule L1 pages 3 and 6. The analysis indicates that the NPV associated with continued execution of the Surge program approved by the Commission in Case No. U-20162 is $82.0 million favorable to customers when compared to just the baseline O&M tree trimming spend without the Surge funding. In this instant case, the Company is calculating the NPV using 2022 to 2042 timeframe.

Q55. Was the economic value to customers of the improved reliability from the tree-trimming surge taken into consideration when determining the NPV?

A55. No. The value of the program was based upon the forecasted reduction in revenue requirement that customers would receive through 2042 due to the remaining investment in the Surge program. The analysis did not take into consideration the additional economic benefits that derive from improved reliability as could be calculated utilizing the Interruption Cost Estimation (ICE) Calculator developed by Nexant and the Lawrence Berkeley National Lab (LBNL) as described in "Exhibit A-23, Schedule M8, Lawrence Berkeley National Laboratory Study and Results" sponsored by Witness Pfeuffer.

Q56. How much does the Company expect to reduce costs per line mile trimmed upon achieving a five-year trimming cycle?

A56. Based on the work study completed by ECI, the Company expects its cost per line mile to decrease, on average, by 40% compared to the initial trimming conducted as part of the ETTP.

Q57. How many tree-related trouble events does the Company expect to reduce upon achieving a five-year cycle through the investment surge?

A57. Based upon details from the Company's outage and dispatch management systems, the Company typically attributes approximately 44,700 outage and non-outage events to trees, or 23% of its roughly 192,300 average annual outage and non-outage events the Company experiences. Upon completion of the Surge, the Company's modeling estimates that the tree-related events will be reduced by approximately 43%.

Table 10 Average Annual Outage and Non-Outage Events

Outage and Non-Outage Events	Pre-Surge 2014-2018 Average	5 Year Cycle Achieved	% Reduction
Tree-Related	44,716	25,379	43.2%

Q58. What reliability improvements will be provided through the Surge program?

A58. The Company expects a 40% reduction in tree-related All-Weather SAIDI. This reduction is driven by fewer tree-related events.

Q59. How did the Company determine the percentage reduction in events upon completion of the Surge?

A59. The Company based the 40% reduction upon:

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(1) Accounting for weather variability, the circuits trimmed as part of ETTP show a 72% improvement reduction in events in the year after trimming as compared to the three years prior to trimming the circuit; and

(2) Consultation with ECI indicated a reduction in the cycle length from an effective eight and a half-year cycle to a five-year cycle would reduce events by 35%; and

(3) Benchmarking of peer utilities suggests an improvement in event reductions in excess of 50%.

Q60. What cost savings will be provided through the Surge program?

A60. At the completion of the Surge, tree-related O&M and capital costs for Reactive Maintenance and storm will be lower. With fewer tree-related events, the need for tree crews and Regional Customer operations' overhead crews will be reduced. There will be less of a need to repair and replace assets on the system that have failed because of tree interference. Table 11 shows current O&M and capital cost compared to the projected costs upon completion of the Surge, excluding inflation.

Table 11 Tree Trimming Surge Cost Savings

Estimated Tree-related Annual Cost Savings ($ millions, excluding inflation)			
Cost Category		**Current Cost**	**5 Year Cycle Achieved**
Tree-Related O&M	Tree Trim Reactive	$16.7	$9.4
	Tree Trim Storm	$15.9	$7.3
	Other DO – Service Operations Storm and Trouble	$12.0	$6.0
Tree-Related Capital	Tree Trim Reactive	$3.0	$2.7
	Tree Trim Storm	$18.2	$13.7
	Other DO - Service Operations Storm and Trouble	$73.8	$20.7

Q61. What will reliability performance be if the Surge program is defunded?

A61. Without the increase in funding, the backlog of circuits in need of trimming as part of the ETTP will not be addressed. In 2026, there would be an approximately 7,000-8,000 mile backlog of distribution circuit miles that have yet to be trimmed as part of the ETTP.

The base funding level, absent the Surge, would limit the Company's ability to address miles that have not been trimmed 8+ years ago in a timely manner. Delaying trimming of these miles will lead to an increase in outage and non-outage events, including wire downs, erode customer satisfaction would erode increasing complaints to the MPSC. Ultimately, tree-related reactive and storm costs would also increase, taking away from the funds that were to be allocated to planned investment and maintenance activities.

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Q62. Does it cost more to trim a circuit if it is not trimmed on-cycle?

A62. Yes. As referenced by in the recent cases U-20162 and U-20561, deferring maintenance results in cost escalation as described in the 1997 study funded by International Society of Arboriculture ("ISA") and conducted by ECI, LLC – The Economic Impacts of Deferring Electric Utility Tree Maintenance. Table 12 shows the relative cost, excluding inflation, of deferring maintenance beyond the optimum time – five years after the previous trim for the Company. By deferring maintenance, the Company will need to allocate more funds to trimming the deferred work in a subsequent year.

Table 12 Projected Impact on Cost of Deferring Maintenance

Timing of Trimming	Years since last trim	Relative Cost
Optimum	5	$1
1-year past optimum	6	$1.16 to $1.23
2-years past optimum	7	$1.30 to $1.43
3-years past optimum	8	$1.40 to $1.59
4-years past optimum	9	$1.47 to $1.69

Q63. Will it take more resources to trim a circuit if it is not trimmed on-cycle?

A63. Yes. Longer tree trimming intervals result in higher tree trimming cost over time, as also described in the 1997 ISA study. As illustrated in Figure 3, as the time since last trim continues to grow, the work becomes more complex as trees begin to interfere with the conductors.

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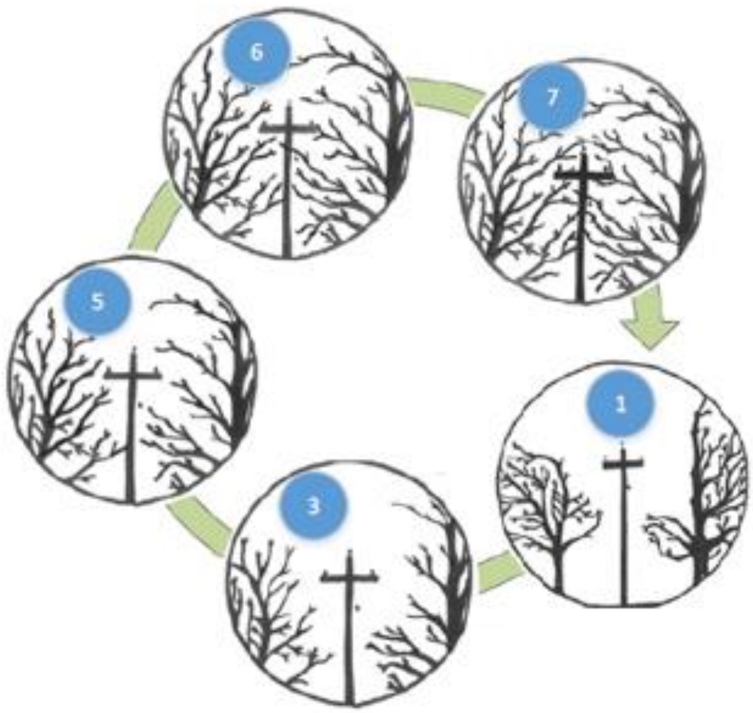
Figure 3 Illustrative Tree Growth Impact on Complexity

(Years since Last Trim)



Reactive Trimming

Q64. Has the Company increased its reactive tree trim activities above what was originally planned for in the Surge plan?

A64. Yes. Reactive trouble activities in support of outages and wire downs are included in the Surge funding. This includes reactive spot trimming which has increased significantly to address circuits with high volumes of customer reliability issues.

Q65. How does spot trimming differ from ETTP trimming?

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A65. Spot trimming is conducted exclusively on poor performing circuits, not yet trimmed to the ETTP specification, that have a high number of sustained and/or momentary outages. Spot trimming involves targeted trimming at select trouble locations to address significant ongoing emergent issues. ETTP trimming addresses the entire circuit and the full trim specification, as discussed above.

Q66. Why can't the spot trimming work wait until the circuit is scheduled for ETTP trimming?

A66. As laid out in the Surge plan, transitioning circuits to ETTP is expensive and it takes years to bring all circuits back to a 5-year cycle. Some circuits need spot trimming before ETTP trimming can be completed in order to improve reliability in the meantime.

Q67. What advantages does spot trimming have over ETTP maintenance trimming?

A67. ETTP circuits are fixed bid and awarded 6-18 months before work begins. Spot trimming is more agile and, when frequent outage circuits present themselves, allows the Company to address some customer concerns within weeks from the time they first arose.

Q68. How much spot trimming work was performed in 2019 and 2020?

A68. Spot trimming was conducted at approximately 8,600 pole locations in 2019, and nearly 12,300 poles in 2020. To put these numbers in context, the electrical system has approximately one million DTE owned pole locations.

Line No.

Q69. Were funds for spot tree trimming included in the Surge modeling in Case No. U-20162 or U-20561?

A69. Yes. They were included as part of "Reactive Maintenance Costs" in Exhibit A-22, Schedule L1, Line 4 on pages 1 and 2. However, the projected cost has increased as the number of pole locations in need of spot trimming has increased

Q70. Why has the amount of spend for spot trimming increased?

A70. The original Surge plan focused almost all resources on trimming as many maintenance miles as possible and didn't accurately account for the increased need for spot trimming to address customer complaints and reliability issues that have resulted from overgrown circuits that have not yet been trimmed to the ETTP specification. This summer highlighted the need for additional spot trimming due to the severe weather and high volume of storms. While the Company is making significant progress to reduce the number of backlog miles on our electrical system, it will still be several years before all circuits are on-cycle. Recognizing the need for additional spot trimming, a portion of the $70M incremental tree trim surge will be allocated to that program.

Q71. How does the Company choose which circuits receive spot trimming?

A71. Circuits that are not in the tree trim maintenance plan, or scheduled for other capital improvement plans, in the current year (and future 12 months) and have had four or more sustained outages and/or nine or more momentary outages in a rolling twelve-month period are reviewed to determine if spot tree trimming is needed. Circuits are then selected and prioritized based on an index that accounts for the concentration on the circuit of the number of customers affected, tree trim schedule, SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary Average Interruption Frequency Index). This selection process has enabled DTE to address a number of the Company's high risk, in terms of service quality, customers who had poor reliability.

Q72. Do you expect the need for spot tree trimming to be reduced as the backlog of non-ETTP circuits are reduced?

A72. Yes. Spot tree trimming is an effective "bridge" for circuits that are outside of the tree trim cycle. We expect the spot tree trim program to be reduced to a minimum once the planned maintenance program has brought the DTE system on a 5-year cycle. Table 13 shows the spot trimming budget declining in the final years of the Surge.

Table 13 Non-Inflation Adjusted Spot Trim Budget 2019-2024

Year	2019 A	2020A	2021	2022	2023	2024
Budget	$5.2M	$8.3M	$8.0M	$5.0	$5.0M	$0.5M

Q73. Have you updated Exhibit A-22, Schedule L1, pages 1 and 2 to include 2020 funding for spot trimming expense and the associated spot trimming savings as the backlog is reduced?

A73. Yes. All expenses and savings have been added into the in line 4, reactive trouble, for the Surge program and line 16 for the Status Quo program.

Q74. Can spot trimming replace ETTP?

A74. No. Spot trimming is not capable of delivering the clearance needed for an entire circuit in order to achieve a 5-year cycle.

<u>Funding Required</u>

Q75. How much funding was included in Case No. U-20561 to trim trees in 2021?

A75. In Case No. U-20561, the tree trimming program was funded to $97.9 million for base tree trim spending. The projected test year in that rate case was May 1, 2020 through April 30, 2021. Since the Company has not filed a subsequent rate case, our base O&M is $97.9 million. Additional funding outside of the base level was also approved as a tree trim regulatory asset – $70.5 million for 2021.

Q76. Is the Company proposing a change to the base O&M for the test period?

A76. Yes. In the last filed rate case (U-20561), Tree Trim's projected base O&M assumed the Company would file a rate case annually and receive inflation. Table 14 shows the base O&M for 2021-2025 in the previous rate case.

Table 14 Base Tree Trim O&M in U-20561

Year	2021	2022	2023	2024	2025
O&M ($M)	99.1	101.5	103.9	106.4	109.0

However, the Company did not file for a rate case in 2020, therefore the current base O&M is $97.9 million. The Company is seeking to "catch up" to the 2023 base O&M, which is $103.9 million. Postponing filing the rate case in 2020 and 2021 has resulted in the Surge program being underfunded by $3.8 million in O&M as laid out in Table 15.

Table 15 Comparison of Actual O&M vs. Projected O&M in U-20561

	2021	2022	Total
Projected (U-20561) ($M)	99.1	101.5	
Actual ($M)	97.9	98.9	
Net Change	*-1.2*	*-2.6*	*-3.8*

Q77. Should the Surge funding be extended through 2023 and 2024?

A77. Yes. Securing funding for the final years of the Surge provides the Company the financial security needed to retain contractors and grow the local work force. The Company is requesting $67.0 million in 2023 and $52.7 million for 2024, as outlined in the previous rate cases.

Q78. Does the Company foresee needing the Surge funding in 2025?

A78. At this time, the Company is not seeking approval for the 2025 Surge Funding; however, there is the possibility we will request it in a future rate case. While we are accelerating the Surge Program with the goal to complete it by the end of 2024, the Company recognizes there are potential risks (e.g. labor market challenges, unknown cost of remaining reclaim miles, etc.) to completing the Surge a year earlier than planned; however, there are too many unknowns to project the need or magnitude of Surge funding required in 2025.

Q79. Can you please describe Exhibit A-13, Schedule C5.6.1?

A79. This page shows the calculation supporting Tree Trimming expenses for the projected test period. The annual amounts approved by the Commission in Case

No. U-20561 are broken down into two categories: tree trim O&M – Base Level (Line 5) and Tree Trim Regulatory Asset – Surge Funding (Line 1). Lines 7 through 9 calculate the projected period O&M amount for the base plan. Line 7 shows the approved O&M Base Level amount of $103.9 million for 2023. Lines 8 and 9 show the historical O&M and adjustment needed to align with the approved base O&M from Case No. U-20561. The $2.748 million adjustment in line 9, column (f) is simply the difference between the historical amount and the approved amount. This adjustment is made to ensure the projected period reflects the amount approved in U-20561 instead of 2020 actual plus inflation.

Tree Trimming Surge Funding Mechanism

Q80. Can you please describe Exhibit A-22, Schedule L1, pages 1 and 2?

A80. These pages show the details of the calculation supporting the Projected Value of the Tree Trimming Program through 2042. The page is broken up into four sections: Surge Program O&M Costs, Status Quo Program O&M Costs, Surge Program Capital Costs, and Status Quo Program Capital Costs. The first section depicts the tree-related O&M costs for the Surge Program. Line (2) depicts the cost to trim the miles needed to achieve a five-year cycle. Line (3) shows the cost of the continuation of the Herbicide Program and is equal to Line (15) as the Herbicide Program. Lines (4), (8), and (9) depict the Tree Trim Reactive Maintenance, Tree Trim Storm, and Other DO Tree-Related O&M Costs, respectively. These costs are dependent upon the projected event reduction resulting from the Surge in investment in the Tree Trim Program. Line (6) conveys the Credit to the Regulatory Asset. This is calculated by taking the Total Tree Trimming O&M Spend in Line (5) and subtracting Line (17), which is the inflation adjusted tree trimming spend for the Status Quo Program. Line (7) conveys the Credit to the Tree Trim

Incremental Surge. This is calculated by taking the Total Tree Trimming O&M Spend in Line (5) and subtracting Line (17), which is the inflation adjusted tree trimming spend for the Status Quo Program and Line (7) which is the Credit to the Regulatory Asset.

The next section demonstrates the tree-related O&M costs for the Status Quo Program, which simply grows at the rate of inflation for Line (17). Lines (16), (19), and (20) are impacted by the Company's ability to maintain limited overhead circuit miles on a five-year cycle. Because an inflation adjusted program does not provide adequate funding to achieve a five-year cycle on the entire system, the reactive, storm, and trouble costs escalate. Line (22) calculates the respective O&M savings of the Surge program as compared to the Status Quo. The third section conveys the Surge program capital costs. The costs shown in Lines (24), (25), and (26) are driven by events and the respective reduction in events expected upon investing in the tree trimming Surge. The fourth section represents the Status Quo Program capital costs. Line (29) conveys the amount of tree trimming charges when trimming in support of replacing an asset on a Blue Sky day, while Line (30) is for Storm spend only. Line (31) depicts the capital spent by the Service Operations organization as a result of tree-related events. Ultimately, the capital savings from investing in the tree trimming Surge program is shown on Line (33).

Q81. What is the total forecasted cost of tree trimming from 2021 through 2024?

A81. Tree trimming costs are expected to be approximately $725.5 million from 2021 through 2024, Exhibit A-22, Schedule L1, page 1, line 5, columns c -f.

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Q82. How is the base rate cost recovery calculated?

A82. The total amount requested for the projected test period ending on October 31, 2023 is $103.9 million. It is the base O&M assumed in the Case No. U-20561 plus inflation to the year 2023. The inflation rate is detailed on Company Witness Ms. Uzenski's Exhibit A-13, Schedule C5.15.

Q83. How much of the cost will be recovered through base rates?

A83. $407.1 million is expected to be recovered through base rates from 2021 to 2024 Exhibit A-22, Schedule L1, page 1, line 8, columns c -h.

Q84. How much cost is the Company expecting to recover outside of base rates?

A84. The Company is proposing to defer Surge costs up to $248.8 million above base rates from 2021 through 2024, Exhibit A-22, Schedule L1, page 1, line 12, columns c -f.

Q85. How does the Company expect to recover the program costs above base rates?

A85. The Commission approved regulatory asset treatment for the incremental costs through 2022 totaling $246.1 million, $156.9 million of which were deferred in 2019 through June 2021 and will be securitized pursuant to the Commission's June 23, 2021 order in Case No. U-21015. Witness Lepczyk discusses how the Company proposes to recover future Surge costs until they can be securitized.

Q86. Why is the Company proposing to securitize the costs?

A86. As previously discussed, the Surge investment is intended to lower future reactive costs that would be incurred given the current state of vegetation near or on the distribution system. Securitization funding recognizes the long-term nature of the program. As the costs are incurred up front and the full savings will not be realized until after the program has matured, recovery over a longer period provides a better matching of costs with the anticipated savings, minimizing the cost impact to customers.

Resourcing the Tree Trimming Surge

Q87. How many resources do you need to meet the accelerated Surge goals?

A87. To complete the Surge by the end of 2024, the Company estimates needing an average of 1,500 trimmers.

Q88. Do you expect to maintain a stable number of trimmers on property throughout the year?

A88. While the Company expects to employ an average of 1,500 tree trimmers beginning in 2022, in practice there will likely be resource swings related to seasonality, market crew availability, and natural rotation of outsource crews back to their home areas.

Q89. How will the tree trimming work be resourced?

A89. The Company will use a mix of local and non-local crews to conduct the work. The Company will not be able to achieve the plan through the utilization of local trimmers only and will need to continue to utilize qualified tree-trimming crews from outside of our service territory. The long-term plan is to achieve an adequate level of qualified local workers to displace the non-local workers.

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Q90. What's the difference between a local tree trimmer and a non-local trimmer?

A90. A local trimmer lives within reasonable driving distance of the DTE Electric service territory and makes union wages. Non-local trimmers normally work in other parts of the country but have come to work for DTE Electric contractors on a temporary basis. A non-local trimmer makes union wages but also requires a daily per diem rate to cover room and board. These requirements make non-local trimmers more expensive than local trimmers.

Q91. Are there any risks to maintaining and growing the Company's current level of trimmer resources?

A91. Yes. The Company faces several risks that could erode its current non-local trimmer population:

(1) Due to the Company's location in a colder climate, many non-local trimmers do not want to work in the area during the winter months. This is important because to obtain an average of 1,500 trimmers, the Company will need to peak at a higher trimmer volume during the summer months to make up for seasonal shortfalls. In the winter of 2020-2021 DTE was able to maintain the majority of outsource crews on property thereby reducing the need for additional summer crews.

(2) The market for non-local trimmers has been tight for the last several years. Trimmers are in high demand due to the utility industry's collective renewed focus on tree trimming. If DTE Electric does not stay on pace with market rates (labor and equipment costs), non-local trimmers will leave for other utilities.

(3) DTE Electric requires specialized climbing tree-trimming workers due to its high percentage of backlot construction. Safe and experienced climbing crews

are difficult to acquire, and it could be difficult to grow the work force past 1,300 to deal with summer peaks.

(4) Large weather events, such as hurricanes, often draw traveling non-local trimmers from across the country for the long overtime and generous per diem rates. Not only could this delay implementation of our Surge program due to a temporary loss of workforce, but trimmers could choose not to return after the storm if other opportunities prove more attractive.

(5) The constraints and slow down of global supply chains due COVID-19 have limited contractors ability to secure additional equipment such as bucket trucks and specialized equipment. Without the proper equipment, contractors are not able to efficiently add more resources on property.

Q92. Are there other resource concerns related to COVID-19?

A92. Yes, if a vaccine mandate is required for our workforce, we may experience significant disruptions. Depending on if other utilities require the vaccine, our outsource resources may leave for other opportunities. Further, we may see disengagement or loss of our local workforce if individuals feel strongly against the vaccine. A significant loss in our workforce, even for a short period of time in response to the vaccine mandate will pose significant challenges.

Q93. What is the Company doing to mitigate these risks?

A93. The Company has a set of options to mitigate resource risks in the short term. We will monitor market rates (labor and equipment costs) to keep pace with increases and we are exploring ways to incentivize the out of area crews to remain in Michigan during the colder months. This past winter, we were able to retain crews on property with the assurance of continued work through the remainder of the year. The implementation of multi-year contracts provides the opportunity to attract and retain the workforce year-to-year. Additionally, this risk is mitigated by having 4-5 tree trimming vendors on property each year because it provides the ability to leverage multiple companies' resourcing pools when additional resources are needed. Long-term we are working on implementing different initiatives to grow our local workforce as explained below.

Q94. What is the Company's plan to create additional local tree trimmers?

A94. The Company has several pathways and initiatives in place or in progress to grow the local workforce:

(1) The Company has partnered with the City of Detroit, IBEW Local 17, and its tree-trimming contractors to develop and implement a pre-woodsman training pilot program to satisfy the demand for qualified tree trimmers. The pilot tree trimming academy is located within the City of Detroit and facilitates training that is aimed at preparing local resident candidates to work as woodsmen. Once candidates complete the pre-woodsman program, graduates enter the nine-day boot camp that was previously designed in partnership with the Company, IBEW Local 17, and the Company's tree-trimming contractors. The boot camp gives participants intensive training and hands-on work experience on subjects such as safety, climbing systems, climbing techniques, arborist equipment, arborist tools, commercial vehicle operation, tree species identification, communication with line crews, customer relations, and aerial rescue techniques. Boot camp graduates enter the Line Clearance Tree Trimming Apprentice Program. The 5,000-hour apprenticeship program, which includes

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160 hours of classroom training, is recognized by the Department of Labor as an approved apprenticeship program and, as one of two programs in the United States, is benchmarked throughout the industry. The first cohort completed the tree trimming academy this past spring, and as of November 2021, 36 individuals have graduated from the program, with 100% of them receiving job offers upon graduation. Due to the collaborative outreach effort and positive reception the academy has received thus far, there is already a waitlist for 2022's cohort.

(2) The Company has implemented a pilot tree-trimming training program into the Vocational Village at Parnall Correctional Facility in Jackson. The training program was developed to allow returning citizens to directly enter the apprenticeship program upon leaving the correctional facility. In selecting applicants, the Vocational Village administration heavily weighs the applicant's county of residence to decrease the distance they would have to commute to work once they are released. To date the Company has paired 23 graduates with jobs.

(3) The Company is working with our local contractors to encourage them to continue to hire new trimmers through their normal processes. Typically, this method of hiring has primarily been used to replace attrition but, due to the increase in future work volume, we are requesting that they attempt additional staff augmentation outside of DTE led activities.

Q95. What other efforts is the Company undertaking to recruit local talent?

A95. The Company is partnering with Local 17 and its contractors to reach out to local high schools, career fairs, and local nonprofit organizations to introduce the tree-trimming trade to interested candidates.

Herbicide Program

Q96. What is the herbicide program?

A96. The Company uses EPA-regulated herbicides to replace mechanical removal of vegetation from the right-of-way with a chemical treatment, which will only control the tree species with the potential to grow into electrical wires. The Company has created the program using industry best practices that were collected and developed through benchmarking and by working with an outside consultant – ECI. The Company uses herbicides that include foliar herbicide treatment, basal herbicide treatment, and dormant stem treatment.

Q97. How much did the herbicide program cost in 2019 and 2020, and how much is it expected to cost in 2021

A97. The Company spent $0.7 million in 2019 as it was starting up the program and spent $1.3 million on its herbicide program in 2020. Forecasted spend for 2021 is $1.2 million

Q98. How much does the Company plan to spend on the herbicide program in 2022?

A98. The Company plans to spend $2.0 million as outlined in previous rate cases.

Q99. What are the benefits of the herbicide program?

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A99. The herbicide treatment will reduce the future cost of maintenance trimming in the right-of-way by reducing tree density. There are other advantages besides realizing cost savings. As tree density and brush height decreases, the electrical system becomes more reliable and the right-of-way becomes more accessible and safer.

Q100. Are there any additional benefits to treating the right-of-way with herbicides?

A100. Yes. Treating the right of ways increases accessibility for our overhead crews, making it safer and easier to access areas in the event of downed wires or broken equipment. Also, because grasses and shrubs are not affected by the herbicide treatment, the area will become a habitat for pollinators, birds, and small mammals. The treatment will also target invasive plant species, limiting their spread.

Measuring Progress

Q101. How will the Company evaluate the results of the Tree Trimming Surge?

A101. In compliance with the Commission's Order in Case Nos. U-20162 and U-20561, the Company will provide an annual report detailing circuit performance on March 1st until the Surge program is complete. In addition, the Company will submit a Tree Trimming Effectiveness Report in 2022 to the Commission.

Q102. How will circuit performance be measured in this annual report?

A102. Per the Commission's direction, the Company will provide details on ETTP and surge miles broken out by geographical region and will include:

(1) All activity, costs, and miles trimmed under any and all tree-trimming programs (including 4.8kV Hardening) in the city of Detroit;

(2) Miles completed by service center annually;

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(3) Total ETTP Miles completed by service center;

(4) Miles of backlog yet to be trimmed under the ETTP by service center and the total percentage of backlog work remaining;

(5) Average tree density by service center;

(6) Percentage of work that requires climbing to the extent that DTE has reliable data;

(7) Performance of ETTP circuits compared to non-ETTP circuits;

(8) ETTP costs (both capital and O&M);

(9) Number of employees and contractors directly involved in ETTP;

(10) Tree-related outage reductions;

(11) Tree-related SAIDI reductions; and

(12) ETTP circuit performance comparing average outages for the three years prior to the enhanced trimming with outages in the years after the trimming has been performed.

(13) A description of spot-trimming work done on the 10 worst performing circuits;

Q103. How will the Company evaluate the results of the tree-trimming Surge in its 2022 report?

A103. The Tree Trimming Effectiveness Report, which will be filed in 2022, will provide an overview of the Surge and the benefits customers have received. This evaluation will be based upon data from five years of trimming circuits as part of the ETTP in 2016 through 2021. This will provide five years of historical circuit performance on the ETTP compared to the remainder of the system.

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Conclusion

Q104. Do you recommend this continued investment in the tree-trimming program?

A104. Yes. The tree-trimming program is the most impactful and important program in the Company's long-term investment strategy. The program has shown that it significantly decreases system risk (specifically reduced wire downs), increases reliability (fewer and shorter outages), and will decrease reactive trouble costs. The tree trimming program as proposed is required to provide safe, reliable and affordable electricity to the Company's customers. Without continuing the Surge investment, the distribution system will continue to degrade, resulting in higher risks and lower reliability. I believe this program is right for our customers and I appreciate the Commission's continued support for the program in Case No. U-20561. The Company is requesting approval of 2023 and 2024 Surge funding including continued regulatory asset treatment of the Surge costs in order to execute the program in a way that makes it affordable for customers.

Q105. In your opinion are these expenses reasonable?

A105. Yes, they are. I base my opinion on analysis of past expenses, and the projected requirements for labor and materials to conduct the necessary tree trimming.

Q106. Does this complete your direct testimony?

A106. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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.	))))))	Case No. U-20836

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

TAMARA D. JOHNSON

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Tamara D. Johnson (she/her/hers). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services LLC, which is a subsidiary of DTE Energy (DTE), as Director, Revenue Management and Protection.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company), which is also a subsidiary of DTE.

Q3. What is your educational background?

A3. I earned an undergraduate degree in business administration from Detroit College of Business, with focuses on accounting and finance, and a MBA, with a focus on global management, from University of Phoenix.

Q4. What is your previous work experience?

A4. I have worked at DTE Energy since 2003, progressing in leadership assignments in Corporate Services, Controllers Organization and Customer Service. I have served as Manager of Business Performance for DTE Gas where my responsibilities included long term planning, various strategic initiatives, regulatory support, and management reporting. I have also held a series of strategic and tactical leadership roles throughout Customer Service.

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Q5. What is your current position and what are your current responsibilities?

A5. As Director of the Revenue Management and Protection (RM&P) organization for DTE, I am responsible for the overall direction, strategy, leadership and management of collections, theft mitigation and energy assistance programs for DTE's regulated subsidiaries, DTE Electric and DTE Gas. The RM&P organization is responsible for driving reduced uncollectible expense for DTE Electric and DTE Gas as well as optimizing the Energy Assistance funding for low-income customers. As a member of the Customer Service senior leadership team, I am updated weekly on operational performance measures for all of Customer Service and receive regular updates on financial performance and participate in the development of strategic plans to improve all areas of the Customer Service business.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes, I have sponsored testimony concerning Uncollectible Expense, Merchant Fees, and Low-Income funding in:

- Case No. U-20162 (DTE Electric 2018 General Rate Case)
- Case No. U-20561 (DTE Electric 2019 General Rate Case)
- Case No. U-20642 (DTE Gas 2019 General Rate Case)
- Case No. U-20940 (DTE Gas 2020 General Rate Case)

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Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to:

- provide details of Low-Income programs responding to the impact of the COVID-19 Pandemic
- explain the details of the Company's Low-Income programs
- provide details of DTE's Low-Income Assistance (LIA) credits
- provide details of DTE's Residential Income Assistance credits (RIA)
- propose changes to the tariff language for DTE's Low-Income energy assistance credits
- propose changes to the DTE Electric Company Rate Book
- explain and support the $59.6 million of projected uncollectible expense
- update the level of uncollectible expense

Q8. What exhibits are you sponsoring in this proceeding?

A8. I am supporting the following exhibit:

Exhibit	Schedule	Description
A-13	C5.8	Projected Operation and Maintenance Expenses Uncollectible Accounts

Q9. Was this exhibit prepared by you or under your direction?

A9. Yes, it was.

COVID-19 Pandemic Impact to Low-Income Programs

Q10. What guiding principles did the Company use when initiating responses to the COVID-19 Pandemic?

A10. To better assist our employees in making decisions in moments of service and enable service excellence, the Company has established Four Keys of Service Excellence. These keys include Safe, Caring, Dependable and Efficient. All Customer Service activities pass through the Service Keys. Our desired culture is one where all employees have a service mindset and a strong emotional connection to caring for our customers and each other.

Q11. What programs did the Company initiate as a response to the COVID-19 Pandemic?

A11. The Company devised and implemented several programs in response to the unprecedented COVID-19 pandemic and the Commission's Order in Case No. U-20757, establishing a case for the Commission's response to the COVID-19 pandemic. These programs leveraged government, faith-based, and agency partnerships to effectively coordinate our response to the impact of the COVID-19 pandemic. The Company intensified efforts on community outreach and tapped into creative payment solutions to ensure that our most vulnerable communities were taken care of during this time of crisis.

These programs included:

- Disconnect Suspension
- Expanded Wellness Checks
- Virtual Customer Assistance Days (CAD)

- Low Income Home Energy Assistance Program (LIHEAP) Direct Support
- One Time Balance Reduction Initiative
- Personalized Service Protection Plans
- Low Income Self Sufficiency Plan (LSP) extension
- Medical Hold Policy Extension (including COVID affected customers)
- Agency Partnerships for additional customer assistance
- Community Outreach for Energy Assistance
  - Feet on the street
  - Public Affairs activity

Q12. What was the Company's Disconnect Suspension Program?

A12. Understanding the unprecedented and overwhelming financial impact of the COVID-19 pandemic on communities, DTE was quick to respond by implementing a halt on disconnects for both commercial and residential accounts, that began mid-March 2020 and continued through July 20, 2020. In addition, to ensure the safety and well-being of all customers, the Company took steps to restore any previously disconnected customers.

Q13. What were the Company's Expanded Wellness Checks?

A13. In Spring of 2020, the onset of the COVID-19 pandemic, it was vitally important that customers who may have had their service discontinued for non-pay and had not yet been restored, had access to energy. The Revenue Management & Protection (RM&P) Field Operations Team completed over 1,800 wellness checks that involved door to door inquiries of customers with disconnected service. Restorations were implemented without deposits nor re-connect fees.

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Q14. What are Virtual Customer Assistance Days (CAD)?

A14. The COVID-19 Pandemic created a new landscape of reaching out to our communities. The Company met the challenge by creating avenues to assist our most vulnerable customers at a time when many were unsure of what the future held. The Company held a total of 22 in-person CAD's in 2018-2019. The onsite services included energy assistance, energy efficiency and education and access to various human services agencies. With COVID-19 and the Governor's Executive Orders in 2020, meeting face to face with our customers was no longer a safe option. In response, the Company developed the Virtual CAD. The Virtual CAD utilized 63 CAD representatives trained to identify and assist customers in agency referrals for Low Income Self Sufficiency Program (LSP) and personalized service protection plans and assist customers in State Emergency Relief (SER) applications. The Virtual CAD allowed for resolution of customer issues at a single point of contact. Over 5,000 customers were able to complete a SER application during the 2020 Company's Virtual CAD events. As of October 2021, the Company continues to host virtual CAD events and has completed an additional 4,429 SER applications.

Q15. What is the Low-Income Home Energy Assistance Program (LIHEAP) Direct Support Initiative?

A15. The LIHEAP assists eligible low-income households with their heating and cooling energy costs, bill payment assistance, energy crisis assistance, weatherization and energy-related home repairs. In partnership with the Michigan Department of Health and Human Services (MDHHS) and as part of the Coronavirus Aid, Relief, and Economic Security (CARES) Act, the Company used funding to reduce the arrears of low-income customers. The program supported over 20,000 customers and provided over $13 million in energy assistance over a 30-day period. This collaboration required swift action in defining and identifying eligible customers as well as a team effort in the coordination of communication and system requirements. In addition, the Michigan State Housing Development Authority (MHSDA) through the COVID Emergency Rental Assistance (CERA) has as of October 1, 2021, provided $9.4 million in energy assistance.

Q16. What is the Company's One Time Balance Reduction Initiative?

A16. To assist customers with limited resources during the pandemic, DTE designed a One-Time Balance Reduction Initiative. The initiative targeted three specific segments and Federal Poverty Levels (FPL):

- Priority Segment 1 "Moderate Income"
    - Customers who range from >150%-250% FPL, haven't received assistance and are not eligible to, had good paying history, and are past due as a result of the pandemic
- Priority Segment 2 "Low-Income Senior"
    - Criteria: Customers who are 200% FPL, seniors, received maximum assistance, not eligible for LSP, and are past due.
- Priority Segment 3 "Low-Income (non-Senior)"
    - Criteria: Customers who are 200% FPL, not seniors, received maximum assistance, not eligible for LSP due to account balance, and are past due.

Each segment contained specific criteria with distinct outreach campaigns and customer experiences with the Company also known as customer journeys. In

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addition, customers were encouraged to achieve at least two Energy Waste Reduction (EWR) offerings within 60 days after program enrollment. Those offerings included:

- Download of DTE's Insight App
- Free Home Energy Consultation
- DTE Interactive Home Tour
- Energy Efficiency Assistance Program
- MI Saves Program (200%-250% FPL)

Customers were identified by arrears balance totals and account aging. Based on these criteria customers were required to pay a percentage of their balances. DTE then applied an arrears forgiveness payment to achieve a zero balance for the customer. Customers were also evaluated for the Company's affordable payment plan and enrolled where eligible. Table 1 "One-time Balance Reduction Program Metrics" provides metrics of the initiative.

Table 1 One Time Balance Reduction Program Metrics

	Segment 1	Segment 2	Segment 3	Total
Total Customers Enrolled	665	541	852	2,058
Total Payments Made by Customers (cumulative)	$172,615	$177,810	$184,597	$535,023
Count of Payments Made by Customers (cumulative)	628	528	753	1,909
% of Customers with Payments Made	94%	98%	88%	93%

DTE Balance Reduction ($) Applied (cumulative)	$371,567	$1,222,369	$1,048,330	$2,642,267
Segment 3 LSP Enrollments*			387	387

*These are accounts that became eligible and enrolled in LSP after account balance reduction

Q17. What are the Company's Personalized Service Protection Plans?

A17. The Company quickly recognized the expanding population of customers in need of energy assistance as a result of economic impact of the COVID-19 pandemic. Where customers required more than the standard payment arrangements, the Company demonstrated flexibility in creating personalized payment arrangements that addressed the customer's energy burden, acknowledged the customer's vulnerability and appreciated the need to maintain the customer's dignity during the challenging times.

Q18. What did the Low-Income Self Sufficiency Program Extension entail?

A18. The LSP program allows customers to make affordable monthly payments based on a customer's income with the remaining portion of the customer's bill paid monthly with energy assistance funds. During the pandemic, customers who were unable to meet their plan payment requirements were able to remain in the program. Customer advocates reached out and communicated with gentle reminders and offers of assistance. Additionally, customers were advised of partner agency assistance in catching up with any missed payments.

Q19. What is the Medical Hold Policy Extension?

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A19. The Company's 30-day medical hold policy was broadened to include low-income customers that were physically exposed, infected or quarantined by COVID-19 virus (including influenza).

Q20. What agency partnerships did the Company leverage for additional customer energy assistance?

A20. During the pandemic the Company improved accessibility of energy assistance and activated community partners such as The Salvation Army, United Way, The Heat And Warmth Fund (THAW), and St Vincent DePaul to reach our vulnerable households. This initiative included $10 million in DTE Foundation donation dollars that assisted reducing arrears for customers in crisis. As part of the settlement approved in Case No. U-20642, DTE Gas made a $1.0 million donation in 2020 to THAW, an independent 501(c)3 nonprofit agency providing limited-income individuals and families throughout the State of Michigan with emergency utility assistance.

Q21. What activities were included in the community outreach energy assistance?

A21. As part of the Feet on the Street initiative in August 2020, DTE delivered door hangers to approximately 12,000 residents in the city of Detroit. The doorhanger encouraged customers to call DTE to find ways to lower their bill with payment plans, restore their service, get financial aid, and identify opportunities to improve energy efficiency. Public Affairs collaborated with peer utilities to create a public service announcement campaign connecting customers with pathways to resources for payment assistance. Additional collaborations included community organizations to deploy teams of neighborhood canvassers that reached nearly 130,000 households in targeted communities.

Q22. Are there additional activities centered around COVID-19 relief?

A22. Yes, the Company in partnership with agencies is developing a process to assist customers waiting on the distribution of CERA funds. In addition to the CERA initiative, the Company is working on the next round of LIHEAP Direct Support for December 2021. The Company anticipates matching 25% of the LIHEAP funds provided by MDHHS to be applied to customers between 151%-400%FPL. This will assist customers not eligible for other types of low-income funding due to exceeding the 150% FPL requirement.

Low-Income Program

Q23. What is the goal of the Company's energy assistance programs?

A23. The goal of the Company's energy assistance programs is to gradually reduce arrears owed while encouraging and supporting good payment habits and reducing consumption. This program structure leads to participants reducing their arrear over time and adopting a habit of making regular, affordable payments, albeit subsidized in the short term. The end goal is customers reaching self-sufficiency and being able to afford the actual costs of the energy they consume.

Q24. What are energy assistance programs the Company provides for its low-income customers?

A24. The Company provides a variety of low-income energy assistance through a variety of programs. Those programs include Shut Off Protection Plan (SPP), Energy

Efficiency Assistance (EEA), Low Income Self Sufficiency Plan (LSP) and Low-Income credits such as the Residential Income Assistance (RIA) and Low-Income Assistance (LIA) credits.

Q25. How does the Company's Customer Service group help provide Energy Efficiency Services for low-income customers?

A25. Through partnerships with participating agencies, customers facing challenges paying their utility bills can apply for the Company's Energy Efficiency Services. Customers at or below 200% FPL are then eligible to receive services such as home energy consultations, appliance replacement and home weatherization.

Q26. What is the Shut Off Protection Plan (SPP)?

A26. The SPP is designed to help low-income customers pay overdue balances by dividing it into equal portions that are added to future DTE Electric bills. The payment amount is calculated by dividing the past due balance into smaller payments and projected future monthly bills. These two amounts are combined into a new monthly payment.

Enrollment in SPP is available to low-income customers and senior citizens year-round. Enrollment requires income verification and an initial down payment. The amount of the down payment will affect the monthly payment amount. Making a larger down payment will result in a lower monthly payment amount.

Q27. How many low-income customers are enrolled in the SPP?

A27. As of October 2021, there are an estimated 27,000 identified low-income customers at or below 200% Federal Poverty Level (FPL) enrolled in the SPP.

Q28. What does the Company consider its key Affordable Payment Plan?

A28. The Low-Income Self Sufficiency Plan (LSP) is a low and affordable payment plan for eligible low-income families. The 2019-2020 LSP program year resulted in an 86% success rate compared to SPP's 30% success rate during the same time. Therefore, LSP is the Company's key Affordable Payment Plan. It allows customers to make affordable fixed monthly payments based on their income and energy usage with the remaining portion of their energy bill being paid monthly with energy assistance funds. A dedicated team of customer advocates are available to assist the LSP customers.

Q29. What are the eligibility criteria for LSP candidates?

A29. A customer's household income must be equal to or less than the 150% FPL. In addition, the customer's annual energy consumption cannot exceed $1,600 for electric; $2,150 for gas, and $3,750 for combined accounts. A customer's account must be active and less than $3,000 of arrears at time of enrollment.

Q30. What indicators does the Company use to determine the FPL of potential LSP candidates?

A30. To qualify for this rate program, an electric customer must provide annual evidence of receiving a Home Heating Credit (HHC) or must provide confirmation by an authorized State or Federal agency verifying that the electric customer's total household income does not exceed 150% of the poverty level as published by the United States Department of Health and Human Services. Customers can also qualify for the credit if they receive any of the following: i) assistance from a state emergency relief program; ii) food stamps; or iii) Medicaid.

Q31. What other methods of assistance are there for low-income customers?

A31. The Company continues to administer the LIA credit pilot and RIA credits for qualifying low-income customers.

Q32. What are the key features of the LIA Credit?

A32. The LIA credit (contained in Rate Schedule D1.6) offers qualifying low-income electric customers a $40 per month credit on their bill. While assisting customers with their monthly consumption, the credit allows customers who may not meet eligibility requirements of other programs such as LSP to benefit from the $40 bill reduction each month.

Q33. What currently makes a customer qualified to receive the LIA credit?

A33. To qualify for this rate an electric customer must be at or below 150% FPL.

Q34. Can any qualifying low-income customer currently be eligible to receive the LIA credit?

A34. Yes.

Q35. What are the current key features of the RIA credit?

A35. The RIA credit offers low-income electric customers $7.50 per month credit on their bill. To be eligible, the total household income cannot exceed the 150% FPL, verified by confirmation of an authorized State or Federal agency. The credit is

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renewed annually based on the eligibility requirements. Customers may not receive both an electric RIA and electric LIA credit at the same time.

Q36. What accounting methods does DTE Electric implement for the distribution of the LIA and RIA credits to its low-income customers?

A36. The Case No. U-20561 Order approved the implementation of a low-income deferral to record a regulatory asset for the difference between actual credits issued and the amount in rates.

Q37. Are you proposing any changes to the LIA/ RIA credit program?

A37. Yes. Instead of simply deferring any amounts over the amount in base rates, I am proposing adding more flexibility to the program. Specifically, I propose a mechanism that allows the Company to carry over any unspent RIA and LIA credits from one year to the next. If the credits issued in one year are lower than the base amount, those unused credits could be used to fund assistance in the following year. The details of this revised Low-Income mechanism are supported by Witness Uzenski.

Q38. What levels of RIA and LIA enrollment levels were approved in the DTE Electric's last rate case?

A38. The Case No. U-20561 Order reduced enrollment levels of RIA Credit from 60,000 to 43,000 customers and retained the LIA Credit at 32,000 enrollments. Additionally, the Commission authorized the Company to track enrollments up to the projected enrollment of 60,000 RIA and 50,000 for LIA, to be booked as a regulatory asset.

Q39. Is the Company seeking changes to the level of the RIA credits?

A39. Yes, the Company is forecasting the RIA credit enrollment forecast to be 61,745 customers in the projected test year. Current RIA enrollment is at 64,000 electric low-income customers. All eligible customers seeking the RIA credit are granted enrollment. The numbers continue to trend upward so it is reasonable to expect that enrollments will remain at or above the 60,000 level.

Q40. What is the Company doing to meet the LIA enrollment levels?

A40. In addition to partnering the LIA credit with LSP enrollees, the Company is reviewing and prioritizing the enrollment of 5,000 eligible non-LSP senior customers who currently are receiving the RIA credit.

<u>Low Income Rate Book Language Changes</u>

Q41. Does the Company propose any changes to the rate book language related to the RIA or LIA credits?

A41. Yes, The Company is proposing changes to the RIA and LIA sections of the tariff to standardize and clarify the two sections. The changes are provided in Exhibit A-16 Schedule F8, which is sponsored by Witness Willis, and are summarized below:

1. RIA and LIA already contain qualification provisions including the customer providing annual evidence of receiving Home Heating Credit (HHC) or Medicaid. The Company proposes to modify customer qualification requirements such that customers must verify receipt of one of the following in the last 12 months: HHC, State Emergency Relief, Michigan Energy Assistance Program, Medicaid, or Supplementary Nutrition Assistance Program. The

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Company also proposes that if the customer cannot verify that they meet any of these requirements, a self-attestation form must be completed and provided to the Company. For LIA, the Company is also proposing that in addition to the income verification methods listed above, a customer may qualify with proof of enrollment in the Company's affordable payment plan as sanctioned under the Michigan Energy Assistance Program (MEAP) or having received one-time MEAP assistance in the last 12 months.

2. Clarifying that the LIA credits will be distributed at the Company's discretion.
3. Clarifying that if participation results in a credit balance that it may only be applied to future billed amounts, and that in no case will a refund be issued.

Q42. Is the Company proposing any other changes to the rate book language?

A42. Yes, the Company is updating the tariff to conform with the billing rules as they relate to the age of senior citizen customers.

Q43. Did the COVD-19 pandemic affect any of DTE Electric's programs for low income and seniors?

A43. Yes. On March 10, 2020, the Governor issued Executive Order 2020-4, which was the Declaration of a State of Emergency due to the COVID-19 pandemic. In response, the Company expanded its shutoff protections for low-income and seniors beyond the March 31, 2020 end date through July 10, 2020 to ensure these customers would not experience an interruption of service during this critical time.

Q44. What new initiatives is the Company undertaking to create comprehensive energy assistance for its low-income customer population?

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A44. As a result of the Case No. U-20561 Order and approval of the Case No. U-20929 ex-parte filing, the Company will be launching the Payment Stability Plan (PSP) pilot in January 2022. PSP is the Company's percentage of income payment plan (PIPP).

Q45. What are the details of the PSP pilot?

A45. The PSP pilot is a percentage of income-based program directed at low-income customers at or below 200% of the FPL. PSP is a 2-year pilot starting in first quarter 2022 targeting a maximum of 2,000 low-income customers. The pilot will focus on the importance of affordable energy as it relates to energy burdens for low-income customers by developing a payment program that is based upon a percentage of gross income. The payment amount is based on the household's income during the previous 12 months.

Customers who receive either gas or electric utility service from DTE Gas or DTE Electric will have flat bill payments equivalent to 6% of the household gross income. Customers who receive both gas and electric utility service from the Companies will have flat bill payments equivalent to 10% of the household gross income. PSP Customers will be enrolled in Energy Waste Reduction education and wrap around services where applicable.

Q46. What is the Company doing to capture data to measure the success of the pilot?

A46. The Company is preparing methods to capture data across several characteristics including but not limited to historical consumption, arrears, payment plans, every

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assistance, payment behaviors, and shutoffs. This data will be tracked throughout the duration of the pilot for analysis and reporting.

<u>Uncollectible Expense</u>

Q47. What is Uncollectible Expense?

A47. Uncollectible expense is the income statement impact of recognizing a reserve for the portion of accounts receivable that is considered uncollectible.

Q48. How is uncollectible expense determined?

A48. Uncollectible expense is determined by a review of individual arrearage accounts for DTE Electric and DTE Gas and is recorded separately based on actual uncollectible performance.

Q49. How does DTE Electric determine the accounts receivable (AR) reserve for uncollectible accounts?

A49. DTE Electric uses a balance sheet method. The AR reserve is calculated by applying reserve factors to aged receivables. Customer accounts receivable are classified in 30-day increments (arrears buckets) and a reserve factor is applied to each 30-day increment. The sum of these reserve values represents the total AR reserve. The Uncollectible Expense Calculation is shown in Figure 1.

The reserve factors are recalculated monthly using a rolling average of the ratio of historical write-offs to historical arrears within each arrears bucket (30, 60, 90, etc.). A 12-month rolling average is utilized for residential and small commercial accounts

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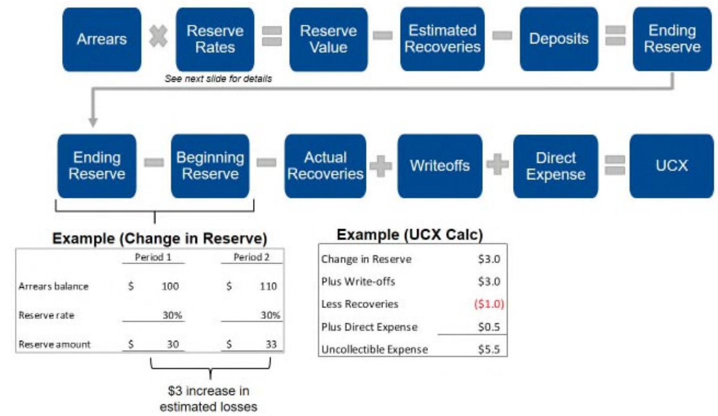
and a 60-month rolling average is utilized for large commercial and industrial accounts.

Figure 1 Uncollectible Expense Calculation



Q50. How does the Company account for uncollectible expense?

A50. Uncollectible expense is recorded in the income statement to reflect the change in the AR reserve. This is calculated as the required increase/decrease in the AR reserve based on the aging analysis just described, plus accounts that were written-off that month, minus accounts that were recovered (on previously written off accounts) that month, plus any DTE Electric matches of low-income funding received.

Q51. What are the Company's write-off procedures?

A51. Routine customer accounts are generally written off once they age to 150 days past the final bill due date, which is issued after service is disconnected. Often, however, there are circumstances that warrant keeping the account on the books until a resolution is obtained – for example, customers with payment arrangements, disputes, etc. Once an account is written off, any payments received on that account are recognized as a recovery. The write-off period of 150 days past the final billing is generally defined as the latest of either the last effective closed agreement date or the last bill due date.

Q52. How is uncollectible expense calculated in this case?

A52. In this instant case the Company is utilizing a three-year average based on actual uncollectible expense for 2017-2020, excluding 2018, resulting in a $59.6 million of uncollectible expense. This amount is calculated on Exhibit A-13, Schedule C5.8 and shown on line 1, column (e) of that same exhibit. The $59.6 million projected amount reflects DTE Electric's planned efforts to keep uncollectible expenses from increasing despite continuing economic challenges for many of our customers.

Q53. Why is the Company excluding the 2018 Uncollectible Expense from the three-year average calculation?

A53. Uncollectible expense was abnormally high during 2018 due to system issues and delayed collections, resulting from the Customer 360 (C360) billing system implementation. This type of system upgrade occurs perhaps once in 10 to 15 years and had a significant impact on collection activities. The impact of those issues is not easily quantified. Therefore, the Company excluded 2018 uncollectible expense from the calculation. When including the 2018 uncollectible expense, the three-year average from 2018-2020 is $71 million. In comparison, when using the 3-year average of 2017, 2019, and 2020, uncollectible expense is $59.6 million which results in a ($2.0) million adjustment from the historical test period. For comparison purposes, the 3-year average of historical net write-offs (including charges to direct expense) is $64 million. This results in a forecast that is more appropriate and beneficial for our customers.

Q54. Is the Company aware of Staff's cash basis methodology of calculating uncollectible expense that was adopted in the Case No. U-20162 Order?

A54. Yes, in the Case No. U-20162 Order, Staff's cash basis methodology for uncollectible expense was adopted by the Commission. The Commission found Staff's method to be the most accurate and least prone to potential forecasting error.

Q55. Are there any reasons the cash basis method should not be used?

A55. Yes. The cash basis method for estimating uncollectible expense is inconsistent with how expense is recorded and with how other costs and revenues are calculated for both MPSC reporting and ratemaking. The Company determines uncollectible accounts expense based on an accrual method as required by the Uniform System of Accounts (USofA); General Instruction number 11. Rates are set to cover the Company's expenses expected to be recorded for account purposes. The estimation of future expenses should therefore be consistent with the practice used to record the actual expenses to ensure recovery of the Company's prudent and reasonable costs. An average of the amounts charged to account 904 provides such consistency. In addition, the cash-basis method does not factor in special circumstances that are accounted for under the accrual method. For example, the write-off of some accounts is delayed because they are being disputed or negotiated and need to show as open in the billing system until a final decision is made. Another example is the decision to temporarily suspend disconnects during 2020 due to the pandemic which drove a significant temporary decline in write-offs. The balances in these examples are expected to be charged-off, so under the Company's accrual method they are fully reserved. These situations would not be reflected in the cash basis method. In

Line No.

addition, direct charges relating to the Company's forgiveness match to low-income customers (Low Income Self Sufficiency Program (LSP) and Low-Income Home Energy Assistance Program (LIHEAP) support), must be included in uncollectible expense. These direct charges related to customer assistance are not accounted for as write-offs; however, they are included in uncollectable expense and reduce the probability that these customers will be disconnected, and the associated balances will be written-off.

Q56. What is the Company's historical net Charge-offs from 2017-2020?

A56. The figure below provides the net Charge-offs from 2017-2020

Figure 2 Net Charge-offs (2017-2019)

Description	2017	2018	2019	2020
Write-offs	$ 64,077,782	$ 99,000,903	$ 107,564,349	$ 79,896,130
Collections	(14,392,650)	(35,676,599)	(35,771,421)	(30,169,706)
Net Write-offs	**$ 49,685,132**	**$ 63,324,304**	**$ 71,792,927**	**$ 49,726,424**
Uncollectible Expense (provision method)	$ 53,004,174	$ 83,597,316	$ 63,350,624	$ 58,783,452
Charges Directly to Expense	(2,143,473)	1,301,367	2,944,560	2,780,072
Total Uncollectible Expense	**$ 50,860,700**	**$ 84,898,683**	**$ 66,295,183**	**$ 61,563,524**

Q57. What events may impact uncollectibles in the projected test period?

A57. There are many factors that could impact or influence uncollectibles during the projected test period. Though we continue to utilize our partnerships to take advantage of all funding opportunities for our customers, unemployment rates, the ending of extended benefits and eviction moratorium, all could impact uncollectibles. Without continued state and federal assistance as provided in the CARES Act and the Coronavirus Response and Relief Supplement Appropriations Act of 2021, there is the potential that bad debt could materially increase.

Q58. What efforts will the Company employ in anticipation of the reduction of COVID-19 relief?

A58. The Company is focusing strategies on collection reform, energy assistance optimization, and refinement of COVID-19 programs that were offered in 2020. Our Customer Advocacy team is developing targeted proactive outreach to drive income challenged customers to existing energy assistance programs through United Way 211. Additionally, to continue driving arrears reduction and accessibility to energy assistance, we are leveraging our existing processes and targeted proactive outreach initiatives for income-challenged customers. Those activities include:

- Outbound call campaign to SPP customers for SER application assistance
- Automated letter campaign to motivate potentially energy assistance eligible customers to seek assistance early to avoid service interruption
- Email blasts to past recipients of SER funding
- Email outreach to customers receiving Notice of Intent (NOI) letters

Accessibility tactics will focus on strategies around expanding the SER application process and community partnerships involving virtual webinars to raise awareness and virtual CADs to promote MEAP and other energy assistance. Understanding the possible mail delivery delays through the United States Postal Service (USPS), the proactive NOI email initiative will notify customers more quickly and will help to prevent service interruption.

Q59. Does this complete your direct testimony?

A59. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

THOMAS W. LACEY

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF THOMAS W. LACEY

Q1. What is your name, business address and by whom are you employed?

A1. My name is Thomas W. Lacey (he/him/his). My business address is One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services, LLC (DTE Energy or DTE) as a Principal Financial Analyst in the Revenue Requirements Department of the Regulatory Affairs Organization.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).

Q3. What is your educational background and business experience?

A3. I received a Bachelor of Science Degree in Accounting from Michigan State University in 1981 and a Master's in Business Administration from Wayne State University in 1992. From 1982 until 2001, I was employed by ANR Pipeline Company (ANR) in the Rates and Regulatory Affairs department. I had several positions of increasing responsibilities within the Rates area, ultimately rising to the position of Senior Rates Analyst. During my nineteen years with ANR, I worked on numerous rate proceedings and filings before the Federal Energy Regulatory Commission (FERC) including rate cases (FERC Docket Nos. RP82-80, RP83-79, RP86-169, RP89-161, RS92-1 and RP94-43). My work was primarily in the areas of cost-of-service and rate design. In 2002, I joined DTE as a Financial Analyst in the Load Research department of Regulatory Affairs. I worked in Load Research until December 2005. My responsibilities within Load Research included extensive work on the 2003 Michigan Consolidated Gas Company (MichCon) rate case (U-13898) and The Detroit Edison Company (Detroit Edison) rate filings. In December 2005, I accepted my current position.

Q4. What are your responsibilities as a Principal Financial Analyst for both DTE Electric and DTE Gas?

A4. As a Principal Financial Analyst, my responsibilities include the preparation of revenue requirements, cost of service and rate design, testimony, exhibits and workpapers, in cases for both DTE Gas and DTE Electric.

Q5. Have you previously sponsored testimony in cases before the Michigan Public Service Commission (MPSC or Commission)?

A5. Yes, I have. I have sponsored testimony in the following cases:

U-13898	MichCon's 2006 Uncollectible Expense True-up Mechanism and Safety and Training Related Expenditure Report
U-15985	MichCon's 2009 General Rate Case Proceeding
U-16290	Reconciliation of MichCon's 2010 Energy Optimization (EO) Program
U-16730	MichCon's 2011 Updated Energy Optimization Plan
U-16751	Reconciliation of the MichCon 2011 EO Program
U-16999	MichCon 2011 General Rate Case Proceeding
U-17288	Reconciliation of the DTE Gas 2012 EO Program
U-17602	Reconciliation of the DTE Electric 2013 EO Program
U-17608	Reconciliation of the DTE Gas 2013 EO Program
U-17632	Reconciliation of the DTE Electric 2013 REP Program
U-17762	DTE Electric 2016/2017 Energy Optimization Plan
U-17763	DTE Gas 2016/2017 Energy Optimization Plan
U-17804	Reconciliation of the DTE Electric 2014 REP Program

U-17832	Reconciliation of the DTE Electric 2014 EO Program
U-17841	Reconciliation of the DTE Gas 2014 EO Program
U-18014	DTE Electric General Rate Case Proceeding
U-18111	DTE Electric REP Plan Proceeding
U-18232	DTE Electric REP (2018) Amended Plan Proceeding
U-18232	DTE Electric REP (2020) Amended Plan Proceeding
U-18248	DTE Electric Capacity Charge
U-18255	DTE Electric General Rate Case Proceeding
U-20029	Reconciliation of the DTE Electric 2017 EWR Program
U-20035	Reconciliation of the DTE Gas 2017 EWR Program
U-20105	DTE Electric Tax Credit A Proceeding
U-20162	DTE Electric General Rate Case Proceeding
U-20172	Reconciliation of the DTE Electric 2017 REP Program
U-20366	Reconciliation of the DTE Electric 2018 EWR Program
U-20369	Reconciliation of the DTE Gas 2018 EWR Program
U-20561	DTE Electric General Rate Case Proceeding
U-20723	Reconciliation of the DTE Electric 2019 REP Program
U-20851	DTE Electric REP (August 2020) Amended Plan Proceeding
U-20866	Reconciliation of the DTE Electric 2020 EWR Program
U-20871	Reconciliation of the DTE Gas 2020 EWR Program
U-21010	Reconciliation of the DTE Electric 2020 REP Program

Q6. Have you previously testified or submitted testimony in any other regulatory proceedings?

A6. Yes. I sponsored testimony in ANR's general rate case in FERC Docket No. RP94-43. I testified at a hearing before the FERC in Docket No. RP94-43.

<u>Purpose of Testimony</u>

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to support the revenue requirements by unit/grouping study (Plant Study) which is being filed in compliance with the Commission's May 8, 2020 Order in DTE Electric's last main rate case (Case No. U-20561). The May 8, 2020 order at pages 220-1 states: "the Commission agrees with the ALJ's determination that the company should provide revenue requirements by plant/unit in its next general rate case. If some or all necessary data is unavailable by plant/unit, DTE Electric should, in consultation with Staff, determine a reasonable method for allocating the available data to plant/units, and provide explanations and evidentiary support in its next rate case filing."

Q8. Did you meet with the Commission's Staff on the methods you used to allocate costs to the plant/units?

A8. Yes. Staff's recommendations are incorporated into Exhibit A-32

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-32	W1	Production COSS by Unit/Grouping

Q10. Was this exhibit prepared by you or under your direction?

A10. Yes, it was.

Q11. What does Exhibit A-32 show?

A11. Exhibit A-32 shows the revenue requirements, based on the Plant Study, by unit/grouping, as required in the Commission's May 8, 2020 order in Case No. U-20561. The total forecasted production costs shown in column (a) of Exhibit A-32, matches, line by line, column (a) of Exhibit A-16, Schedule F1.1,the Company's forecasted production unbundled cost of service (UCOS), supported by Company Witness Maroun. The amounts in column (a) of Exhibit A-32 are allocated to DTE Electric's forty-two (42) production generation unit/groupings, in columns (b) through (as) on Exhibit A-32. The line items in total on Exhibit A-32 match the same line items on Exhibit A-16, Schedule F1.1 in the Company's UCOS.

Q12. Does DTE Electric own any generation resources not included in Exhibits A-16 and A-32?

A12. Yes. The costs associated with Renewable Energy Plan (REP) assets are not included in the Company's UCOS, as they are included in the Company's REP filings, and as a result are not reflected on Exhibit A-32.

Q13. What sources of information did you rely on to determine the revenue requirement by plant/unit?

A13. The inputs for the Plant Study rely on a combination of historic amounts, and forecasted amounts from the projected bridge period and test year in this proceeding. Primarily I relied upon: (1) 2020 historical actual amounts for plant, accumulated reserve, depreciation expense and property taxes, determined by the Company's Asset Management and Tax departments, and (2) forecasted amounts reflected in the various capital, O&M, and financial exhibits supported in this instant case, as more fully described by Company Witness Uzenski in her direct testimony in this case.

Q14. Can you describe how you developed the Plant Study?

A14. I began with Exhibit A-16, Schedule F1.1 from the Company's UCOS. This exhibit is developed by various workpapers, which allocates the various cost, expense and revenue items to rate classes in the Company's UCOS. I used the Production UCOS workpaper produced by Witness Maroun, but instead of allocating costs to rate classes like in a typical UCOS, I allocated these same costs to the forty-two generation units/groupings (17 steam/fossil units, 1 nuclear unit, 1 hydro unit, 21 peaker/other units, Midwest Energy Resource Company (MERC), and Transmission).

Q15. How did you determine how much to allocate to each generation unit?

A15. I performed the allocations in various steps. The Company's breaks costs into five sub-groups based on the MPSC Uniform System of Accounts (USofA): Steam, Nuclear, Hydraulic, Other and Transmission. I assign the costs directly related to plant for each generation type (Steam, Nuclear, Hydraulic, Other and Transmission) to the corresponding group of units of the appropriate type. Next, I allocate the costs amongst the units within each type.

Q16. How did you allocate plant-related costs to the 17 steam units?

A16. In general, I first started with actual 2020 plant, accumulated reserve, and depreciation expenses by unit, supplied to me by the Company's Asset Management group. Second, I determined by plant, the projected changes for these items as reflected in Exhibit A-12, Schedule B5.1, pages 2 and 3 and added them to the 2020 amounts. However, Exhibit A-12, Schedule B5.1, pages 2 and 3, does not breakout capital expenditures by unit. Therefore, I split the plant amounts, by unit, by using ratios based on the project list on page 4 of Schedule B5.1, which does show projects by unit. Next, I adjusted the by amounts on B5.1 page 3, as follows: 85% was added to plant and 15% to accumulated reserve. These adjustments were necessary, to match the plant and accumulated reserve balances reflected in the Company's UCOS. The capital expenditures reflected on Exhibit A-12, Schedule B5.1 page 2 required no adjustment because it had no adjustment in the balances reflected in the Company's UCOS. Finally, I reduced the by unit amounts for projected retirements, as reflected in the Company's reflected in the various capital and financial exhibits supported in this instant case, including the projected retirements of the St, Clair and Trenton plants and the securitization of the River Rouge plant.

Q17. How did you allocate the plant-related costs to the 21 peaker/other units?

A17. Generally, in the same manner as the steam units as described above, except that Exhibit A-12, Schedule B5.1 pages 2 and 3, does not breakout peaker costs by plant, so I used ratios based on the project list on page 4 of Schedule B5.1, which does show peaker/other projects by plant.

Q18. How did you allocate General and Intangible (G&I) plant related costs to the 42 generation units/groupings?

A18. G&I plant related costs were allocated to the 42 generation groupings based on a ratio of the direct total projected plant balance.

Line No.

Q19. How did you allocate Construction Work in Progress (CWIP) to the 42 generation units/groupings?

A19. CWIP is projected in a manner like plant, into Steam, Nuclear, Hydraulic, Other and Transmission. Nuclear, Hydraulic, and Transmission were directly assigned in the Plant Study; Steam and Other were allocated based on direct plant ratios.

Q20. How did you allocate revenues to the 42 generation units/groupings?

A20. In various ways. Other revenues were allocated based on direct plant. Revenue from Electricity Sales was allocated in order to result in a uniform rate of return for each generation unit/grouping. Specifically, I allocated revenue to each generation unit based on its expenses, net of revenue credits and AFUDC, times that unit's proportion of total rate base times total revenue minus total expenses minus total revenue credits and AFUDC. In other words, I assigned the remainder of the revenue requirement needed after accounting for total expenses and AFUDC, in order to produce a net operating income that results in a uniform rate of return for each generation unit/grouping.

Q21. How did you allocate taxes to the 42 generation units/groupings?

A21. In various ways. For example, property taxes were allocated based on projected direct plant. Income taxes were allocated on each unit's rate base. Payroll taxes were allocated on each unit's direct labor cost. Property taxes were allocated on ratios based on actual 2020 property taxes by plant, as calculated by the Company's Tax Department.

Line No.

Q22. How did you allocate working capital to the 42 generation units/groupings?

A22. Working capital items were allocated by four different methods: direct assignment, direct plant ratios, historic direct labor ratios and net plant by unit.

Q23. How did you allocate Operation and Maintenance (O&M) expenses to the 42 generation units/groupings?

A23. Like plant, direct O&M is projected in the financial model using the MPSC Uniform System of Accounts which facilitates assigning costs by generation type and Transmission. I assign the O&M expenses for each generation type (Steam, Nuclear, Hydraulic, and Other) to the corresponding group of units of the appropriate type. Next, I allocate the costs amongst the units within each type. Steam O&M expenses were allocated based on historic O&M ratios, excluding plants that will be retired, during the bridge and projected test periods. Other O&M expenses were allocated based on projected direct plant ratios.

Q24. How did you allocate fuel expenses to the 42 generation units/groupings?

A24. Fuel expenses are projected in manner like plant; into Steam, Nuclear, Hydraulic, and Other (Peakers). Nuclear, and Hydraulic (which has a $0 fuel cost in the UCOS) were directly assigned, Steam and Other fuel expenses were allocated based on historic 2020 fuel costs, except fuel expenses for BWEC. Fuel for BWEC was imputed, as BWEC was not in operation in 2020.

Q25. How did you allocate purchased power expenses to the 42 generation units/groupings?

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A25. Since purchased power is not projected in manner like plant or fuel; into Steam, Nuclear, Hydraulic, and Other (Peakers). I used the projected plant allocator as a default allocator for purchased power.

Q26. How did you allocate Administrative and General O&M expenses to the 42 generation units?

A26. Administrative and General O&M expenses were allocated based on direct historic labor ratios.

Q27. Does this conclude your direct testimony?

A27. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ROBERT J. LEE

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ROBERT J. LEE

Line
No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Robert J. Lee (he/him/his) and my business address is One Energy Plaza, Detroit, Michigan 48226-1279. I am employed by DTE Energy Corporate Services, LLC as Manager of Environmental Management and Safety and am currently the Manager of Environmental Strategy for the Company.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational and work background?

A3. I received a Bachelor of Science Degree in Geology in 1992 and a Master of Science Degree in Environmental Geochemistry in 1994 from the University of Wales. Since completing my formal education, I have practiced continuously in the environmental field with a focus on State and Federal programs mostly in Michigan. My past and current responsibilities include management of several State and Federal environmental programs, including Effluent Limitations Guidelines (ELG), Coal Combustion Residual (CCR), remediation program management, State and Federal construction permit programs, and coal plant retirement. Additionally, I have State and Federal level experience supporting and developing legislative and rule-making initiatives.

Q4. What are your current job responsibilities?

A4. I have worked for DTE Energy for 17 years. I am currently the Manager of Environmental Strategy and my focus is on complex and strategic environmental initiatives that are critical to DTE. In this role I focus on environmental strategy, policy, and regulatory development and am responsible for key environmental programs at the State and Federal level that are critical to the Company's compliance, strategic direction, and generation strategy. I am responsible for the Company's strategy and approach for compliance with the CCR and ELG programs, coal plant retirement, asset reuse, and waste program.

Q5. What was your professional experience prior to joining DTE Energy?

A5. From 1994 to 2004, I worked in the environmental consulting and environmental engineering fields in several different capacities, and in roles with progressively increasing responsibilities. During this time, I was a Project Manager of complex multi-media environmental projects. I managed a wide variety of projects for various industries focusing on remediation project management, solid waste compliance and project management, National Pollutant Discharge Elimination System (NPDES) permit management, and obtaining and managing State and Federal permits. I also performed complex multi-site due diligence and liability management. I worked for a variety of industries including utility, cement production, and landfill industry sectors.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I have sponsored testimony in the following cases:

U-16999	2012 DTE Gas General Rate Case
U-17999	2015 DTE Gas General Rate Case
U-20642	2019 DTE Gas General Rate Case
U-20940	2021 DTE Gas General Rate Case

<u>Purpose of Testimony</u>

Q7. What is the purpose of your testimony?

A7. I will describe the status of two significant Environmental Protection Agency (EPA) regulations, the Steam Electric Effluent Limitation Guidelines (ELG) Rule and the Coal Combustion Residuals (CCR) Rule, which impact the Company's coal-fired power plants.

Q8. Are you sponsoring any exhibits?

A8. I am supporting the following exhibit:

Exhibit	Schedule	Description
A-12	B5.1.1	Coal Combustion Residual Unit Closures

Q9. Was this exhibit prepared by you or under your direction?

A9. Yes, it was.

Q10. Is the Company requesting recovery of capital expenditures associated with compliance to upcoming EPA regulations?

A10. Yes. As shown in Company Witness Morren's Exhibit A-12, Schedule B5.1, the Company is in the process of developing and implementing several ELG and CCR compliance projects including:

- Monroe Dry Fly Ash Conversion (ELG)
- Monroe Bottom Ash Conversion (ELG)
- Monroe FGD Wastewater (ELG)
- Sibley Quarry Landfill Modification (CCR)
- Monroe Bottom Ash Basin Closure (CCR)

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No.

- Monroe Fly Ash Basin Closure (CCR)
- River Rouge Bottom Ash Basin Closure (CCR)
- St. Clair Bottom Ash Basin Closure (CCR)

<u>Effluent Limit Guidelines</u>

Q11. What are the Effluent Limit Guidelines (ELGs)?

A11. Effluent Limit Guidelines are national wastewater discharge standards that are developed by EPA on an industry-by-industry basis. These are technology-based regulations, and are intended to represent the greatest pollutant reductions that are economically achievable for an industry. EPA promulgated the Steam Electric Power Generating ELGs in 1974, and amended the regulations in 1977, 1978, 1980, 1982, 2015 and 2020. The regulations cover wastewater discharges from power plants operating by utilities. The Steam Electric regulations are incorporated into National Pollutant Discharge Elimination System (NPDES) permits.

Q12. Can you describe the recent revisions to EPA's Steam Electric Power Generating (SEPG) ELGs?

A12. The EPA's SEPG ELGs regulate how electric utilities must manage certain wastewaters. On October 13, 2020, the EPA finalized the ELG Reconsideration Rule which revised some requirements from the 2015 version of the ELG rule. The Reconsideration Rule revised requirements for two specific waste streams produced by steam electric power plants: flue gas desulfuriszation (FGD) wastewater and bottom ash transport water (BATW). The Reconsideration Rule provides additional compliance opportunities by finalizing subcategories, such as for the cessation of coal burning activities.

Q13. When does DTE need to comply with revised ELGs?

A13. The Reconsideration Rule provides new opportunities for DTE Electric to evaluate existing ELG compliance strategies and make any necessary adjustments to ensure full compliance with the ELGs in a cost-effective manner. The EPA set the applicability dates for BATW and FGD wastewater retrofits to be "as soon as possible" beginning October 13, 2021, and no later than December 31, 2025. For facilities pursuing the FGD wastewater Voluntary Incentives Program, detailed further below, compliance shall be achieved no later than December 31, 2028. Compliance schedules for individual facilities and individual waste streams are determined through issuance of new NPDES permits by the State of Michigan.

Q14. What are DTE's options for ELG compliance?

A14. The Company has two options to achieve compliance under the Reconsideration Rule for BATW and FGD wastewater. The first option is to design and engineer new technologies that are compliant with the ELG requirements for BATW and FGD wastewater. The second option is to pursue a compliance subcategory for BATW and FGD wastewater that EPA has established within the Reconsideration Rule. One compliance subcategory would allow for companies to attain compliance with the ELGs for both BATW and FGD wastewater by ceasing coal burning activities, which includes retiring coal-fired unit(s), or converting unit(s) to other fuels. If companies are willing to certify that unit(s) will retire the use of coal or refuel, they can continue to operate those units until their specified coal retirement date, which is required to be before December 31, 2028. For the electrical generating unit(s) that certify under this subcategory, companies will need to maintain the existing standard limits already in effect for BATW and FGD wastewater discharges.

In addition to the cessation of coal burning activities subcategory, the Reconsideration Rule also provides a compliance subcategory specific to FGD wastewater. The Reconsideration Rule established Best Available Technology (BAT) standard discharge limits for FGD wastewater discharges, and further, finalized a subcategory called the Voluntary Incentive Program (VIP). Under the VIP, companies may choose to meet more stringent effluent limits established by EPA based on the model technology of membrane filtration or zero-liquid discharge. If a company chooses the VIP option, then the applicability date for FGD wastewater compliance will be December 31, 2028.

To establish compliance for either of the subcategories detailed previously, companies were required to submit a Notice of Planned Participation (NOPP) to the state permitting agency (Environment, Great Lakes & Energy [EGLE]) by October 13, 2021. Once submitted, companies are required to submit annual progress reports to EGLE to ensure the commitment of compliance under the subcategories.

Q15. Can you describe the NOPP filing?

A15. To establish compliance for the compliance subcategories detailed above, companies were required to submit an NOPP to the state permitting agency (EGLE) by October 13, 2021.

The cessation of coal NOPP included: (1) identification of the electric generating unit (EGU) intended to achieve permanent cessation of coal combustion; (2) expected date that each EGU is projected to achieve permanent cessation of coal combustion; (3) whether each date represents a retirement or a fuel conversion; (4) whether each retirement or fuel conversion has been approved by a regulatory body; and (5) identification of the relevant regulatory body. In addition, the NOPP must include a copy of the most recent Integrated Resource Plan (IRP) for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs, certification of EGU cessation under the CCR rule, or other documentation supporting that the EGU will permanently cease the combustion of coal by December 31, 2028. The NOPP must include, for each such EGU, a timeline to achieve the permanent cessation of coal combustion. Each timeline must include interim milestones and the projected dates of completion. A cessation of coal NOPP was submitted for Belle River Power Plant.

The VIP NOPP for FGD wastewater included: (1) Identification of the facility opting to comply with the VIP discharge requirements; (2) Specify what technology or technologies are projected to be used to comply with those requirements; (3) Provide a detailed engineering dependency chart and accompanying narrative demonstrating when and how the system(s) and any accompanying disposal requirements will be achieved by December 31, 2028. A VIP NOPP was submitted for Monroe Power Plant.

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Q16. What is DTE Electric's compliance strategy for Belle River Power Plant?

A16. At Belle River Power Plant, fly ash is currently collected dry and therefore there are no Fly Ash Transport Water (FATW) implications. Additionally, the power plant was constructed and operates without FGDs, therefore, there is no FGD wastewater. However, the bottom ash is currently collected using transport water and the ELG Reconsideration Rule requires the Company to achieve compliance with BATW discharge requirements. DTE submitted the NOPP for cessation of coal at Belle River Power Plant on October 13, 2021. Please see Company Witness Morren's testimony for pathways the Company is considering for Belle River Power Plant ELG compliance.

Q17. What is DTE Electric's compliance strategy for Monroe Power Plant?

A17. At the Monroe Power Plant, the Company is currently implementing projects for FATW ELG compliance according to the 2015 ELG Rule that will allow the plant to continue operating beyond 2023. For BATW wastewater ELG compliance, the Company will achieve compliance by the end of 2025. For FGD wastewater ELG compliance, the Company will achieve compliance based on one of two compliance options detailed above. If a BAT is selected, compliance must be achieved by December 31, 2025. If a technology that qualifies for the VIP is selected, compliance must be achieved by December 31, 2028. DTE submitted the NOPP for the VIP at Monroe Power Plant on October 13, 2021. Please see Company Witness Morren's testimony for pathways the Company is considering for Monroe Power Plant ELG compliance.

The ELG rule does not impact the Tier 2 plants as River Rouge power plant retired in 2021, and St. Clair and Trenton Channel Power Plants will retire by 2022.

Coal Combustion Residuals

Q18. Can you describe the EPA's Coal Combustion Residuals (CCR) Rule and its impact on the Company's coal-fired units?

A18. The EPA's CCR Rule regulates how electric utilities must manage and dispose of coal combustion residuals in landfills and impoundments. On August 28, 2020, the EPA published an amendment to the CCR rule (the Part A Rule) that requires all unlined surface impoundments to cease receipt of waste and initiate closure as soon as technically feasible but by no later than April 11, 2021. The August 28, 2020 amendment also provided utilities the ability to request site-specific alternative closure deadlines through a demonstration process to obtain EPA approval. On November 12, 2020, EPA published an additional amendment to the CCR rule (the Part B Rule) that allows utilities the opportunity to demonstrate that their unlined surface impoundments have an alternate liner system that is as protective as a CCR rule compliant liner system. The demonstration processes included in the Part A Rule and Part B Rule require EPA approval to continue operating the companies unlined CCR surface impoundments.

Q19. Can you describe the Company's strategy to comply with the amended closure provisions of the CCR Rule?

A19. The Company has submitted a Part A Rule demonstration for St. Clair Bottom Ash Basins, requesting an alternative closure deadline based on cessation of coal fired generation in spring of 2022, and a commitment to complete closure of the unit by

October 17, 2023. The company has submitted Part B applications to perform Alternate Liner Demonstrations for Monroe Fly Ash Basin, Belle River Bottom Ash Basins, and Belle River Diversion Basin. The EPA is currently reviewing the submittals, the outcome of their review will determine the timeline for closure of these unlined surface impoundments.

As shown in Company Witness Morren's testimony, the Company is closing and has removed all ash from the River Rouge Bottom Ash Basin, which requires groundwater remediation before the closure can be considered complete. The company is currently closing the Monroe Bottom Ash Basin by removal of all ash and making infrastructure improvements at Sibley Quarry Landfill to enhance the storage capability to be able to accept the CCR material coming from the Monroe Bottom Ash Basin.

Closure of the River Rouge and Monroe Bottom Ash Basins were initiated in accordance with the timeline required by the CCR rule, and closure is required to be complete within five years (with the opportunity for five 2-year extensions if necessary).

The Company's coal ash landfills—Range Road Landfill, Monroe CCR Landfill, and Sibley Quarry Landfill, will continue to receive CCR through the active life of the respective power plants that deposit ash at these locations. The above mentioned landfills will be closed in place by installing cover material over the ash deposits at the end of their active life.

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CCR Unit Expenditures

Q20. How is the Company addressing the Commission's request as noted on page 75 in MPSC Case No. U-20561 for a more holistic presentation of CCR-related project components, costs, and timing in this case?

A20. The Company is providing details on the historic and the projected expenditures required to comply with CCR regulations at Company facilities. Expected timing and preliminary cost projections for CCR-related projects are shown in more detail in this attached Exhibit A-12 Schedule B5.1.1. Additionally, Company Witness Uzenski provides details on the recovery of CCR-related costs through regulated rates in Exhibit A-30 Schedule U-1 and discussed in her testimony.

Q21. What information are you presenting in this case related to CCR expenses and projects?

A21. The Company is providing details on the historic and the projected expenditures required to comply with CCR regulations at Company facilities.

Q22. Please provide additional details on Company CCR expenditures.

A22. Attached Exhibit A-12 Schedule B5.1.1 provides the historic and projected CCR O&M and capital expenditures at the Company's ten (10) CCR sites. Those ten sites include the bottom ash basins at Belle River, Monroe, River Rouge, and St. Clair Power Plants, the St. Clair Scrubber Basin, the Belle River diversion basin, the Monroe Fly Ash Impoundment, and the landfills at Range Road, Sibley Quarry, and Monroe.

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Q23. What capital expenditures are shown in Exhibit A-12 Schedule B5.1.1?

A23. Actual and projected CCR facility closure cost expenditures are shown in columns f, g, and h of Exhibit A-12 Schedule B5.1.1. For those facilities closing by removal, the capital expenditures reflect dewatering the basins and excavating and disposing of the CCR material. For those facilities closing in-place, the capital expenditures reflect capping the facility with clay, soil, and vegetation; and for Sibley Quarry, also include projected capital expenditures for installation of subsequent chimney drain lifts. It should be noted that these capital expenditures are being provided for time periods beyond those relevant to this rate case proceeding and conform to the requirements of the Commission Order in Case No. U-20561.

Q24. What O&M expenditures are shown in Exhibit A-12 Schedule B5.1.1?

A24. Historic and projected test period O&M costs are shown for each CCR site. Beyond the date of site closure, forecasted O&M costs for ongoing monitoring and site preservation are also provided, in addition to O&M costs for remediation that are accounted for in environmental reserve accounts.

Q25. What does the environmental reserve represent in Exhibit A-12 Schedule B5.1.1?

A25. The Company has two environmental reserves associated with CCR expenses. At River Rouge, an environmental reserve addresses the liability to remedy groundwater contamination at the River Rouge Bottom Ash Basin. Groundwater remediation is required by the corrective action and closure sections of the CCR rule. Groundwater concentrations must meet the groundwater protection standards established for the unit in order to fully certify the closure of the basin under the

CCR rule. At Range Road Landfill, an environmental reserve addresses groundwater contamination at the landfill. Groundwater remediation at Range Road Landfill is required by Part 115 of the Natural Resources and Environmental Protection Act of 1994, as amended. The groundwater is managed through an EGLE approved Remedial Action Plan that includes operation and maintenance of two french drain systems to capture off-site shallow groundwater to the northwest, northeast, and east of the landfill.

Q26. How did the Company develop forecasts for future CCR-related costs that in some cases will not come to fruition for more than 20 years?

A26. Forecasted capital expenditures are best estimates of site modifications required to meet currently known State and Federal regulations. O&M expenditures are based on current costs to operate CCR sites and engineering judgement of future site preservation and monitoring costs.

Q27. Are other Company witnesses providing CCR-related information?

A27. Yes. Company Witness Uzenski provides details on the recovery of CCR-related costs through regulated rates. Additionally, Company Witness Morren describes CCR-related projects and supports the corresponding costs.

Q28. Does this complete your direct testimony?

A28. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

TIMOTHY J. LEPCZYK

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF TIMOTHY J LEPCZYK

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Timothy J. Lepczyk (he/him/his). My business address is DTE Energy Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC.

Q2. What is your position and on whose behalf are you testifying?

A2. I am Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy Company (DTE Energy) and its subsidiaries including DTE Electric Company (DTE Electric or Company). I accepted the position of Assistant Treasurer and Director of Corporate Finance in August 2021. I am testifying on behalf of DTE Electric.

Q3. What are your responsibilities as Assistant Treasurer and Director of Corporate Finance for DTE Electric?

A3. I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities such as the raising of both equity capital and capital markets debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist in maintaining relationships with the commercial and investment banking community, interact with the rating agencies, and execute corporate financial policies, particularly in the areas of balance sheet management, debt issuances, and agency ratings. In addition, I manage the Company's capital investment approval and review process along with managing the Company's property and liability insurance function.

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Q4. What is your educational background?

A4. I graduated from Georgetown University in 2004 with a Bachelor of Business Administration degree, with a concentration in International Business. In 2008, I graduated with my MBA from the University of Michigan, with a focus in Finance and Corporate Strategy.

Q5. What is your professional experience?

A5. I began my employment with Ford Motor Company in the summer of 2004 as a financial analyst within that company's Dearborn Stamping facility. In 2006, I left to pursue my MBA. In 2008, after graduation, I went to work for Booz & Company, a management consultancy, where I focused on the automotive and industrial sectors. I worked at Booz & Company from 2008 until 2013 when I joined DTE Energy.

In 2013, I joined DTE Energy as a Manager on the Corporate Strategy team where I was the lead analyst for various projects and studies primarily relating to the Gas Storage and Pipeline business. In 2014, I formally accepted a position within the Gas Storage and Pipeline team as Manager in their strategy group where I was responsible for various economic analyses (e.g., natural gas supply and demand fundamentals) and for assessing potential new acquisition opportunities.

In 2016, I accepted the position of Manager for the Corporate Development team where I was responsible for managing DTE Energy's capital investment process and various valuation processes (for example, DTE Energy's annual Goodwill impairment assessment). In addition, I led broader strategy initiatives including the

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analysis, which ultimately led to our decision to spin off the Midstream business segment.

In 2021, I accepted my current position, Assistant Treasurer and Director of Corporate Finance, Insurance and Development

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. No.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to support DTE Electric's projected capital structure and the cost of its long and short-term debt to be used in the determination of DTE Electric's overall rate of return in this proceeding. I also am recommending that any of the Company's future tree trim surge expenditures be financed through the issuance of long-term debt and equity.

Q8. How is your testimony organized?

A8. My testimony is organized as follows:

I. Summary of Recommendations
II. Development of Capital Structure
III. Development of Cost Rates
IV Securitization
V. Summary and Conclusions

Q9. Are you supporting any exhibits?

A9. Yes, I am supporting the following exhibits:

Exhibit	Schedule	Description
A-1	A2	Historical Financial Metrics
A-4	D2	Cost of Long-Term Debt – as of December 31, 2020
A-4	D3	Cost of Short-Term Debt – Twelve Month Period Ended December 31, 2020
A-4	D4	Cost of Preferred and Preference Stock – Twelve Month Period Ended December 31, 2020

A-4	D5	Cost of Common Shareholders' Equity – Twelve Month Period Ended December 31, 2020
A-11	A2	Projected Financial Metrics
A-14	D1.1	Peer Group Common Equity
A-14	D2	Cost of Long-Term Debt – as of October 31, 2023
A-14	D3	Cost of Short-Term Debt – Twelve Month Period Ended October 31, 2023
A-14	D4	Cost of Preferred and Preference Stock – Twelve Month Period Ended October 31, 2023
A-18	H1	Current and Historical Credit Ratings
A-18	H2	Recent Utility Corporate Bond Issuances

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

I. SUMMARY OF RECOMMENDATIONS

Q11. What permanent capital structure are you recommending for the projected test year to be utilized in determining the overall rate of return calculation for DTE Electric?

A11. I am recommending a projected permanent capital structure of 50% long-term debt and 50% common equity. Permanent capital is long-term perpetual capital. Common equity, preferred stock and long-term debt are sources of permanent capital. Since the Company does not have any preferred stock, I am recommending the permanent capital structure to be made up of 50% long-term debt and 50% common equity. This permanent capital structure is reflected in DTE Electric's projected permanent capital structure as of October 31, 2023, as shown in Exhibit A-14, Schedule D1, which is supported by Company Witness Vangilder. This capital structure is necessitated by the business and financial risks confronting DTE Electric, which I will discuss in greater detail later in my testimony.

Q12. What is your forecast for DTE Electric's cost of long-term debt, short-term debt and preferred stock for the 12-month period ending October 31, 2023?

A12. I am forecasting 3.69% for the cost of DTE Electric's long-term debt, and 1.74% for the cost of DTE Electric's short-term debt. The Company does not have preferred stock and therefore it has no cost rate. Exhibit A-14, Schedule D2 supports the cost rate for long-term debt. Exhibit A-14, Schedule D3 supports the cost rate for short-term debt.

II. DEVELOPMENT OF CAPITAL STRUCTURE

Q13. What do you mean by capital structure?

A13. A company's capital structure includes the amount of equity and debt necessary to support the operations of its business and is defined differently by regulators, finance professionals and rating agencies. Total regulatory capital structure typically includes long-term debt, short-term debt, preferred stock, common equity, deferred taxes, deferred job development investment tax credits, and deferred investment tax credits. Permanent capital structure includes only long-term debt and equity. Rating agencies calculate a company's capital structure using short-term debt, long-term debt, preferred stock, common equity and other adjustments. The rating agencies adjust debt to include items like capital and operating leases, unfunded pension liabilities, power purchase agreements and asset retirement obligations.

Q14. Why is a sound capital structure important?

A14. It is important to have a financially sound capital structure in order to ensure that a company can obtain needed capital. A sound capital structure produces capital costs that are reasonable and equitable. Also, it is important that the overall return on capital be sufficient to assure financial confidence in a firm and to allow it to raise the funds that are necessary to operate its business at reasonable costs and terms. A sound capital structure is in the best interests of the customers as it ensures the continued viability of the company.

Q15. How does risk affect a firm's capital structure?

A15. In general, a firm such as DTE Electric faces two types of risk: business risk and financial risk. Business risk is a result of systemic and non-systemic risk. Systemic risks are broad economic risks faced by all firms. Non-systemic risks are risks specifically identified as those faced by the individual firm. Financial risk is the risk that common equity shareholders face to the extent that a firm issues debt to finance real assets. Debtholders (also known as bondholders) have priority over equity shareholders in the event of corporate bankruptcy. Thus, the greater the amount of debt held by a firm, the greater the risk to common shareholders. It is essential that a firm recognizes the dynamics of these risks and adjusts its underlying debt and equity components to produce a sound capital structure.

Q16. How does a company's capital structure impact its ability to attract capital?

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A16. Having a weak or highly leveraged capital structure may lead to higher required returns on equity and a higher cost of debt. It also can impact the company's ability to obtain capital. For example, a company with a highly leveraged capital structure may lose its investment grade rating from the rating agencies. Non-investment grade companies have a limited investor base and a more limited access to capital than investment grade companies. Moreover, during periods of diminished capital liquidity, even investment grade companies can have limited access to new capital sources. It is important to consider how extreme market reactions to singular events impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. Furthermore, rating agencies allow little or no time for a company to correct and improve its capital structure before lowering its credit rating. Conversely, companies must be proactive to target and achieve the midpoint of the range of rating agency financial metrics to have a better chance to maintain current ratings.

Q17. Will higher debt levels in a capital structure affect the cost of debt?

A17. Yes. The cost of debt increases as more debt is added to the capital structure. Further, higher debt levels can increase the risk of a downgrade by the rating agencies. A lower credit rating means greater credit risk such that investors will require a higher return to invest in a company, thereby increasing the cost of debt for that company.

Q18. For DTE Electric's defined projected test year, what capital structure are you recommending for DTE Electric in this case?

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A18. For the projected test year, the permanent capital structure that I am recommending includes long-term debt and equity as shown on Exhibit A-14, Schedule D1, that is supported by Witness Vangilder. Within this regulatory capital structure, I am recommending a projected test year permanent capital structure that has 50% long-term debt and 50% common equity. This is the same permanent capital structure authorized by the Commission in the last general rate case, Case No. U-20561.

Q19. Does the Company believe that a 50/50 capital structure is the optimal capital structure for DTE Electric?

A19. No. To reduce the number of contested positions in the instant case, the Company is using the structure authorized in the May 8, 2020 order in Case No. U-20561. However, as the Company has argued in past rate cases, it believes the more appropriate capital structure for DTE Electric is closer to that of its peers. Exhibit A-14, Schedule D1.1 shows DTE Electric peers having a capital structure made up of 48% long-term debt and 52% common equity. A 50% equity level gives the Company less protection in the event of an unforeseen market event and may impact DTE Electric's ability to access capital during the future test period should an unforeseen market shock occur.

Q20. Is the proposed ratio of 50% common equity to total permanent capitalization in line with DTE Electric's peers?

A20. No. The common equity ratio requested in this case is lower than that of the Company's peers. As shown on Exhibit A-14 Schedule D1.1, the average equity ratio for DTE Electric peers was approximately 52%. DTE Electric's targeted 50% equity ratio is a reasonable level given that the average ratio of the peer group is higher at 52%. The data was obtained from S&P Global Market Intelligence (SNL) for the most recent fiscal year available per peer company.

DTE Electric believes its requested 50% is reasonable and below the equity ratio of its peers across the country and within Michigan.

Q21. Does the intense capital investment program contribute to the need for a higher level of equity within the capital structure?

A21. It is imperative that DTE Electric be viewed as a financially sound firm with a solid investment grade rating to ensure the reasonableness and competitiveness of capital costs. DTE Electric will be financing and funding over $6.5 billion of electric capital expenditures for the period January 2021 through October 2023. In a period of intense capital investment, a sound capital structure and a favorable regulatory environment are essential to maintain the financial well-being of the Company. Should the Company face any unforeseen or negative impacts to its financial health, a higher equity balance may be needed. The common equity balance and equity ratio projected for the test year in the instant case will hopefully enable the Company to maintain strong credit ratings and withstand any shocks in the financial markets, thereby ensuring a smooth implementation of its capital expenditure program.

Q22. Is DTE Electric committed to maintaining a 50% equity ratio in its capital structure?

A22. Yes. At December 31, 2020, DTE Electric's equity ratio was 50%. DTE Electric is committed to maintaining a 50% equity ratio and has demonstrated its

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commitment to its targeted equity ratio by receiving equity infusions from DTE Energy. DTE Energy has made reasonable efforts to strengthen DTE Electric's credit quality by infusing over $1.3 billion of common equity from 2016-2020. DTE Electric has received equity infusion of about $550 million in 2021 and will infuse the amounts necessary in future years to maintain a 50% common equity ratio.

III. DEVELOPMENT OF COST RATES

Q23. What were DTE Electric's historical financial and ratemaking metrics from 2016 through 2020?

A23. DTE Electric's historical financial and ratemaking metrics for each of the previous five years (2016 through 2020) are detailed in Exhibit A-1, Schedule A2. The historical financial calculations include year-end financial metrics and are calculated on a financial basis from DTE Electric's financial reports. The historical ratemaking metrics include year-end financial metrics and are calculated from DTE Electric's annual regulatory filings.

Q24. What is the cost of long-term debt outstanding at December 31, 2020?

A24. Exhibit A-4, Schedule D2 calculates the cost of the long-term debt outstanding at December 31, 2020. As shown in the exhibit and schedule, the cost of long-term debt also includes agent's fees, commissions and financing expenses and is calculated on the net proceeds to the Company. The weighted average cost of debt is computed based on the total annual costs to the Company divided by the total principal amount outstanding at year-end. The cost of long-term debt at December 31, 2020 was 3.98%.

Q25. What is the cost of short-term debt outstanding at December 31, 2020?

A25. The cost of short-term borrowings for the 13-month period ended December 31, 2020 was 2.47%. The cost of short-term debt consists of the 1) interest rate on short-term borrowings, and 2) credit facility fees associated with the credit agreements necessary for the issuance of short-term debt. See Exhibit A-4, Schedule D3.

Q26. What was the approved cost of equity as of December 31, 2020?

A26. DTE Electric's authorized cost of common shareholders' equity as of December 31, 2020 was 9.9% and was approved in Case No. U-20561. DTE Electric does not have any preferred stock. See Exhibit A-4, Schedules D4 and D5.

Q27. What does DTE Electric project its financial metrics to be in the test year?

A27. DTE Electric's forecasted ratemaking metrics are available in Exhibit A-11, Schedule A2. Forecasted calculations include metrics for the fully projected test year. The forecasted ratemaking metrics for the projected test year are to be reported assuming (i) full rate relief as requested, and (ii) zero rate relief.

Q28. What is the purpose of Exhibit A-14, Schedule D2?

A28. The purpose of Exhibit A-14, Schedule D2 is to calculate DTE Electric's projected weighted average long-term debt costs as of October 31, 2023. Starting with the actual December 31, 2020 long-term debt outstanding, any known and measurable changes for each year were made to arrive at the projected balance as of October 31, 2023. Known and measurable changes that have occurred or are projected to occur from January 1, 2021 through October 31, 2023 include:

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Table 1 Issuances and Redemptions

	Amount ($000)	Date	Rate
Issuance	$575,000	March 2021	1.90%
Issuance	$425,000	March 2021	3.25%
Redemption	($250,000)	April 2021	3.90%
Redemption	($32,800)	May 2021	7.00%
Redemption	($37,600)	August 2021	6.90%
Issuance	$82,350	September 2021	1.45%
Issuance	$59,175	September 2021	1.35%
Redemption	($82,350)	September 2021	1.45%
Redemption	($59,175)	September 2021	1.45%
Issuance	$500,000	March 2022	3.10%
Issuance	$400,000	May 2022	3.10%
Redemption	($250,000)	June 2022	2.65%
Redemption	($66,000)	September 2022	6.95%
Issuance	$400,000	February 2023	3.20%
Issuance	$340,000	October 2023	3.20%
Net change in debt	$2,003,600		

The interest rate for the debt issuances is based on forward long-term borrowing rates of A-rated utilities, which is comparable to DTE Electric's credit rating. These forward rates were obtained from Bloomberg, which is a leading provider of financial data, news and analytics, in October 2021. Including the planned long-term debt issuance, the weighted average long-term debt cost as of October 31, 2023 is projected to be 3.69%.

Q29. Why did you use long-term debt cost on a net proceeds basis?

A29. The actual costs would be understated if the net proceeds were not used in the base calculation. The net proceeds methodology accounts for underwriters' compensation and other financing expenses and is shown on Exhibit A-14,

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Schedule D2. A portion of any amount financed is used to fund these costs, such that the Company has access to less than the full amount financed. As a result, these fees and expenses are shown as a reduction in proceeds from the issuance of new securities, thereby increasing the effective cost of the issuance above the stated coupon rate.

Q30. How did you determine the interest rate on short-term debt on Exhibit A-14, Schedule D3?

A30. The cost of short-term debt consists of: 1) the interest rate on short-term borrowings, and 2) facility fees associated with the credit agreements necessary for the issuance of short-term debt (Facility Fees).

The interest rate on short-term borrowings was determined by adding a 90-basis point (bps) spread to forecasted three-month short-term debt rate. A spread of 90 bps was used because that is the spread for borrowings under DTE Electric's credit facility.

The average forecast for the three-month short-term debt rate for the 13-month period ending October 31, 2023 is 0.50%. The forecast was obtained from Bloomberg in October 2021. Adding the spread of 90 bps to the forecasted 3-month rate of 0.50% brings the interest rate on short-term borrowings to a total of 1.40%.

The cost of short-term debt also includes Facility Fees associated with maintaining credit facilities. Credit facilities provide short-term liquidity and can be used to support the issuance of commercial paper or can be drawn upon to provide short-

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term funding. DTE Electric presently has a $500 million credit agreement that expires in April 2024, so the costs related to the facility are known and measurable. Facility Fees for the credit agreement for the 12 months ending October 31, 2023 are $0.9 million. The cost of short-term debt including Facility Fees for the projected test period is 1.74%.

Q31. What is the purpose of Exhibit A-14, Schedule D4?

A31. Exhibit A-14, Schedule D4 shows that DTE Electric does not plan to have preferred or preference stock during the projected test period.

Q32. What are the Company's current and historical credit ratings?

A32. Exhibit A-18, Schedule H1 shows DTE Electric's and DTE Energy's current and historical credit ratings, along with associated rating agency outlooks, for the previous five years as published by Standard & Poor's (S&P), Moody's Investors Service (Moody's), and Fitch Ratings. The credit ratings include senior unsecured debt, senior secured debt, and commercial paper ratings.

Q33. Have there been recent public utility bond issuances?

A33. Yes. I have provided details of public utility bond issuances for the three-month period prior to, through the three-month period after, each of DTE Electric's long-term debt offerings issued during the 24 months prior to September of 2021. This summary includes the issue date, issuing company, type of offering (either secured or unsecured), amount of offering, coupon rate, maturity date, structure of offering, S&P and Moody's ratings, and issue spread. See Exhibit A-18, Schedule H2.

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IV. SECURITIZATION

Q34. How has the tree trim surge regulatory asset been financed in prior rate cases?

A34. On May 2, 2019, the Commission issued its order in Case No. U-20162 whereby the Company was authorized a return on the tree trim surge regulatory asset at the short-term debt cost rate of 3.56%. (p. 80). In Case No. U-20561, the return on tree trim surge regulatory asset was calculated at that same authorized short-term debt rate.

Q35. How does the Company propose to treat the tree trim surge regulatory asset in this instant case?

A35. The Company now recommends that any future tree trimming surge expenditures by the Company be financed through the issuance of long-term debt and equity until the time the Company can execute a securitization financing for these amounts.

Q36. Why is the Company recommending this change?

A36. Given the temporary status, defined in Case No. U-20162, of the Tree Trim Surge regulatory asset, the Company did not pursue financing with permanent long-term debt and equity capital, but rather financed with short-term working capital including short-term debt. Thus, this was matching the financing costs with the return the Company was earning on the regulatory asset. In its order for Case No. U-21015, the Commission considered the regulatory asset to have been financed with permanent capital and specified that proceeds of the securitization should be used for the repayment of long-term debt and equity. Consistent with that financing order, any future tree trim surge regulatory asset amounts should be treated as being financed with permanent long-term debt and equity capital and receive the respective return. I have directed Witness Vangilder to calculate the return on projected tree trim surge regulatory asset in that fashion.

V. SUMMARY AND CONCLUSIONS

Q37. Can you summarize your recommendation and conclusions?

A37. Due to the financial and business risks faced by the Company, a projected permanent capital structure of 50% long-term debt and 50% common equity is reasonable and prudent. DTE Energy has taken reasonable actions to strengthen DTE Electric's credit quality and has done so by infusing over $1.3 billion of common equity from 2016 through 2020 and will continue to do so as needed. The plan calls for additional equity infusions and retained earnings growth through the test period in the amount necessary to maintain the Company at no less than a ratio of 50% equity to permanent capital at October 31, 2023. For the projected year, the cost of short-term debt is projected to be 1.74%, and the cost of long-term debt is projected to be 3.69%. I believe these expenses and measures are reasonable, prudent and necessary. In addition, I recommend that any of the Company's future tree trim surge expenditures be financed through the issuance of long-term debt and equity.

Q38. Does this complete your direct testimony?

A38. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20836
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MARKUS B. LEUKER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MARCUS B. LEUKER

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Markus B. Leuker (he/him/his). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).

Q2. What is your present position with the Company?

A2. I am the Manager of Corporate Energy Forecasting.

Q3. What is your educational background?

A3. I received a Bachelor of Science in Business Administration from Xavier University in Cincinnati, Ohio with a concentration in Marketing and Management in 1991. I received a Master of Business Administration from Xavier University in Cincinnati, Ohio in 1998. I have also completed several Company sponsored courses and attended various seminars to further my professional development.

Q4. What is your work experience?

A4. I joined the Company in November 2010 as Manager, Corporate Energy Forecasting. Prior to DTE Electric, I worked for IHS/CSM Worldwide as a Sr. Manager, North American Advisory Services where I led the pursuit, development, execution and delivery of key client projects. Some of my experiences at IHS/CSM Worldwide included: Market Research & Analysis, Market Opportunity Analysis, Business Modeling and Strategic Analysis, Regulatory Market Assessment, and Financial and Scenario Analysis. In addition to my experience with DTE Electric and IHS, I worked as North American Manager, Market Research & Analysis for Visteon Corporation where I managed global coordination of the research function and led a team of researchers in various studies including customer and competitor research, new product creation, and customer satisfaction. I have also had prior experience in the utility industry working as a Senior Analyst at Cinergy Corporation (currently Duke Energy). While at Cinergy, I worked on various non-regulated activities and regulated marketing activities.

Q5. What are your duties as Manager, Corporate Energy Forecasting?

A5. I am responsible for the development of the economic and electric sales forecasting activities for DTE Electric. These activities include data collection, statistical analysis of data, forecast model building and interaction with other departments on forecast-related activities. My role also includes the preparation of long-term (one year or greater) sales forecasts, short-term (monthly) forecasts, next day forecasts, and the economic forecast that supports the sales forecast.

Q6. Do you belong to any professional organizations?

A6. I am a member of Edison Electric Institute's (EEI) Load Forecasting Group (LFG). The LFG's purpose is to enhance load forecasting capabilities by exchanging information among the group's base of experienced and knowledgeable load forecasters. I am also a member of the Detroit Association for Business Economics (DABE). DABE discusses economic issues affecting Southeastern Michigan.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission?

A7. Yes. I sponsored testimony in the following cases:

U-17049 2012 Energy Optimization Plan

Line No.		
1	U-17097	2013 PSCR Plan
2	U-17302	2013 Renewable Energy Plan Update
3	U-17319	2014 PSCR Plan
4	U-17680	2015 PSCR Plan
5	U-17762	2016-17 Energy Optimization Plan
6	U-17767	DTE Electric General Rate Case
7	U-17793	2015 Renewable Energy Plan
8	U-17920	2016 PSCR Plan
9	U-18014	DTE Electric General Rate Case
10	U-18111	2016 Amended Renewable Energy Plan
11	U-18143	2017 PSCR Plan
12	U-18255	DTE Electric General Rate Case
13	U-18262	2018-19 Energy Waste Reduction Plan
14	U-18403	2018 PSCR Plan
15	U-18419	2017 Certificate of Necessity
16	U-18232	2018 Renewable Energy Plan
17	U-20162	DTE Electric General Rate Case
18	U-20221	2019 PSCR Plan
19	U-20471	2019 Integrated Resource Plan
20	U-20561	DTE Electric General Rate Case
21	U-18232	2020 Amended Renewable Plan

Line No.

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to provide the Company's current electric sales, maximum demand and system output forecast for the period 2021-2026, including the projected 12-month test period November 2022 through October 2023. I will discuss the outlook for the national and local economy which is the basis of the forecast. I will describe how the forecast of electric sales, maximum demand and system output is developed. My testimony will support the reasonableness of the electric sales forecast used by DTE Electric in this proceeding.

Q9. Are you supporting any exhibits?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-5	E1	Annual Sales by Major Customer Classes and System Output 2016-2020 Historical
A-15	E1	Annual Sales by Major Customer Classes and System Output 2021-2026 Forecast
A-15	E2	Annual System Output, Maximum Demand and Load Factor
A-15	E3	Projected Period Known and Measurable Changes to Sales
A-15	E4	Summary of Economic Outlook
A-15	E5	Variance of Weather-Normalized Electric Sales and Peak and ITRON's Benchmarking Survey Results

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. How is your testimony organized?

A11. My testimony consists of the following parts:

Part I: Economic Outlook

Part II: Forecast Development and Assumptions

Part III: Historical and Current Electric Forecast Sales and Demand

Part IV: Electric Load Forecast Accuracy

Part I: Economic Outlook

Q12. What effect has the Coronavirus (COVID-19 or COVID) outbreak had on the national economy?

A12. COVID infections and fears caused the economy to contract sharply in the first half of 2020, but after suffering that initial setback and still enduring local COVID outbreaks, economic activity has been recovering. Starting with the third quarter of 2020, real gross domestic product has expanded each quarter. At present, real gross domestic product is tracking to grow by 7.4 percent over 2021, while real personal consumption expenditures and real disposable personal income are heading toward 8.4 percent and 3.4 percent annual growth, respectively. The Consumer Price Index for All Urban Consumers (CPI-U) is tracking to increase by 3.3 percent in 2021, and U.S. light vehicle production for the year is pointed toward 10.02 million units, or 16.2 percent growth.

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Q13. What is the outlook for the national economy in 2022 and 2023 compared to 2021?

A13. Gross domestic product is expected to increase by 4.8 percent in 2022 and by 1.7 percent in 2023. Disposable personal income is expected to decrease by 1.8 percent in 2022 and increase by 1.9 percent in 2023. Personal consumption expenditures are expected to increase by 4.3 percent in 2022 and by 2.4 percent in 2023. These measures from the national income and product accounts are in real terms, meaning that inflation has been removed from them. The CPI-U is forecast to increase by 2.1 percent in 2022 and by 2.0 percent in 2023. Total light vehicle production in the United States is forecast to reach 11.67 million units in 2022 and 11.66 million in 2023.

Q14. What is the outlook for Southeast Michigan's economy in 2022 and 2023 compared to 2021?

A14. Total non-farm employment is forecast to increase by 4.8 percent in 2022 and by 2.1 percent in 2023. Natural resources, mining, and construction employment is expected to rise by 0.2 percent in 2022 and decline by 1.4 percent in 2023. Total private non-manufacturing employment is forecast to rise by 5.7 percent in 2022 and by 2.6 percent in 2023. In the government sector employment is expected to rise by 2.9 percent in 2022 and by 0.2 percent in 2023. Manufacturing employment is forecast to increase by 1.8 percent in 2022 and by 0.7 percent in 2023. Southeast Michigan automotive production is expected to attain a level of 1.82 million vehicles in 2022 and 2.03 million in 2023. Population is forecast to decline by 0.15 percent in 2022 and by 0.06 percent in 2023.

Part II: Forecast Development and Assumptions

Q15. What is the general approach used in developing the forecast of DTE Electric's service area electric sales and system output?

A15. The general approach reflects widely accepted industry standards for electricity forecasting, including end-use and regression modeling. This approach has, over time, provided reasonable forecasts for DTE Electric service area electric sales. For most sectors of the forecast, electric sales levels are related to the various economic, technological, regulatory, and demographic factors that have affected them in the past.

The procedure begins with the assembly of historical data relating to the various sectors of the forecast. The data is examined and the factors that are statistically significant in explaining electric sales are identified using regression techniques. The forecast models are developed internally, employing the appropriate regression equations. The Company receives national and local economic forecasts from various sources[1] that are then used as inputs in the forecast models to calculate projected future sales levels. Economic variables (explanatory factors) include motor vehicle production, population, employment, and others.

The forecast is developed separately for each of the major customer classifications: Residential, Small Commercial and Industrial (C&I), Large C&I and Other. The sales in the Residential and Small C&I classes are forecast using separate Statistically Adjusted End-Use (SAE) models in Metrix ND, an ITRON software

[1] Sources include, but are not limited to: IHS Markit, Auto Forecast Solutions, Automotive News, Moody's Analytics, Bureau of Economic Analysis, Bureau of Labor Statistics, Energy Information Administration

program. The Large C&I class sales are forecast using a combination of regression equations and trend models for seven supersector markets. The Other (Street Lighting) forecast is provided by Company Witness Bellini. Net system output is forecast as the sum of the electric sales values for the four categories and the projected losses.

Q16. What weather assumptions are in the load forecast?

A16. Weather is one of the primary variables used in each customer class forecast model. In each model, actual weather is used to understand the unique relationship that a customer class's energy consumption has with weather. In regression modeling, a coefficient is measured to quantify this impact. Once the coefficient is calculated, it is applied to the weather assumed in the forecast horizon. In the forecast horizon, normal weather is assumed as the most prudent form of weather expectations for the future.

Q17. How does DTE Electric define normal weather?

A17. Normal weather is defined as a 15-year average of historical values from 2006-2020. Daily average temperature is converted to weather variables such as heating degree days (HDDs) and cooling degree days (CDDs) using a base of 65 degrees. HDDs are calculated by subtracting average daily temperature from 65 degrees Fahrenheit. Conversely, CDDs are calculated by subtracting 65 degrees Fahrenheit from average daily temperature. As a result, this process calculates and defines normal HDDs and CDDs for a given day, month and year.

Q18. How was the Residential Class forecast developed?

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A18. Electricity sales in the Residential class were forecast using the SAE model which specifies energy use as a function of 15 end-uses, including customer owned solar and electric vehicle demand, along with factors that affect the end-use requirements such as economic activity and weather. The Residential class forecast begins with a basic end-use model with appliance saturation projections and average electricity usage per end-use provided by a Company-conducted residential appliance saturation survey and the Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS) for the East North East Central region in which DTE Electric operates. Residential Energy Waste Reduction (EWR) programs are applied directly to the corresponding end-uses in the SAE model. The combination of appliance saturations and average electricity per end-use is indexed and calibrated to the Company's usage per customer for the base year to create an electricity forecast for each end use.

End-use intensities are combined with utilization variables which reflect how much the end-use is utilized. For Residential, the primary variables used to explain utilization are weather, real personal income, population, and households. Additionally, resulting from the COVID-19 pandemic, Michigan mobility data was integrated into the model through a "wedge" due to the shift in electricity consumption patterns caused by shelter-in-place and social distancing policies. The wedge and associated shifts in electricity consumption are described later in my testimony. The utilization variables are then combined with the end-use intensities to compute an explanatory variable. Along with seasonal factors, the resulting explanatory variable is then regressed against the Company's Residential monthly

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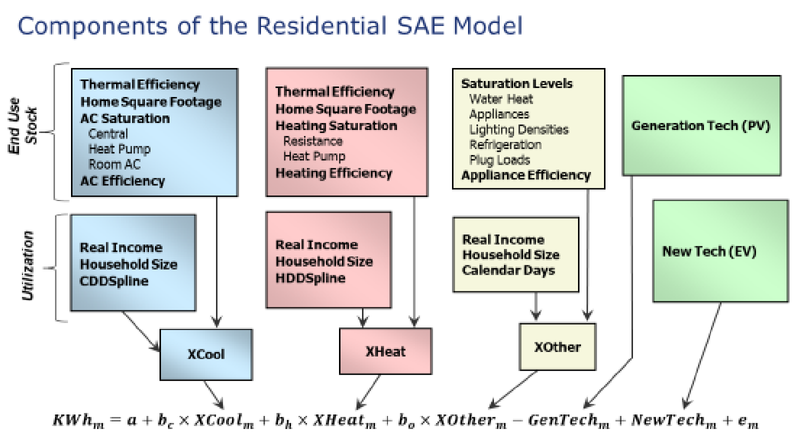
use per customer sales. The model effectively acts as the statistical adjustment and calibrates the end-use forecast to the Company's historical sales.

The number of residential customers was forecasted using historical and projected households for southeast Michigan provided by IHS Markit. Customer counts are modeled using a regression, with households as the primary explanatory variable. The customer forecast is then multiplied by the use per customer from the SAE model to produce the total Residential class sales forecast. For more conceptual detail about residential SAE modeling, refer to Figure 1 below[2].

Figure 1



Q19. How was the Small C&I forecast developed?

A19. Similar to the Residential class forecast, Small C&I class sales are also forecast using the SAE model, utilizing 11 end-uses including customer owned solar and electric vehicle demand. Additionally, Small C&I EWR programs are incorporated directly into the SAE model. The Small C&I sales forecast begins with a basic end-use model with saturation projections and average electricity usage per end-use

[2] Source: ITRON, Inc.

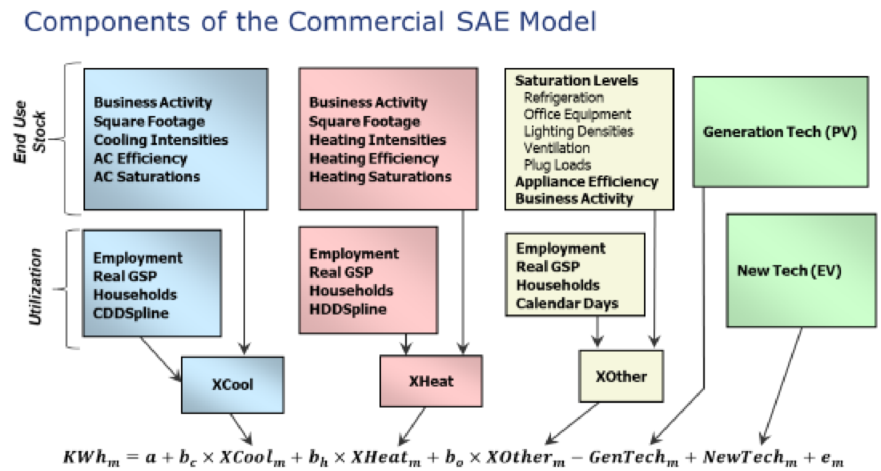
derived from the EIA's Commercial Building Energy Consumption Survey (CBECS) for the East North Central region in which DTE Electric operates. Since Small C&I buildings within the DTE Electric service territory consume electricity differently, the projections are weighted by intensity and prevalence of 11 different building types as defined by the EIA. To better calibrate these projections to the Company's service area, employment values are used to weight the saturations and average electricity usage per end-use is enhanced with the Company's service area employment data. The combination of saturations and average electricity per end-use is indexed and calibrated to the Company's usage per customer for the base year to create an electricity forecast for each end-use.

For Small C&I, the primary variables used to explain utilization are weather, gross state product, non-manufacturing employment and households. Additionally, resulting from the COVID-19 pandemic, Michigan mobility data was integrated into the model through a "wedge" due to the shift in electricity consumption patterns caused by shelter-in-place and social distancing policies. The utilization variables are then combined with the end-use intensities to compute an explanatory variable. Along with seasonal factors, the resulting explanatory variable is then regressed against the Company's Small C&I monthly use per customer sales.

Small C&I customers are modeled using a regression with Residential customers as the primary variable. The customer forecast is then multiplied by the use per customer from the SAE model to produce the total Small C&I class sales forecast. For more conceptual information regarding Commercial SAE modeling, refer to Figure 2 shown below. [3]

[3] Source: ITRON, Inc.

Figure 2



Q20. How was the Large C&I forecast developed?

A20. The Large C&I forecast begins by disaggregating all primary service sales into seven distinct supersector markets. Granular market segments defined by the customer's North American Industry Classification System (NAICS) code are aggregated into supersectors defined by the Bureau of Labor Statistics. The seven supersectors include medical and education, transportation, trade and utility (TTU), offices, other markets, automotive, other manufacturing, and steel. Econometric models, a commonly used technique among utility forecasters, are used to forecast sales for the Company's service territory at the supersector level. Individual regression equations are applied to all the supersectors, using various explanatory variables such as corresponding supersector employment, automotive production, weather, and cumulative energy waste reduction savings, to drive the forecast. Three supersectors, TTU, offices, and automotive also include a "wedge" as an explanatory driver to capture the variance, driven by the coronavirus pandemic, that the employment driver cannot fully explain. For example, the "wedge" in offices and automotive captures remote working and in TTU it captures reduced store

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hours. The steel market uses a regression for the first forecast year and an exponential smoothing model for the remainder of the forecast. The regression results are evaluated for reasonableness and validated through various model statistics.

Regression modeling does not account for incremental growth of emerging technologies (photovoltaics and electric vehicles). Therefore, it is necessary to make post-regression adjustments to the forecast to incorporate future technology and customer specific closings or expansions. The three main post-regression adjustments include distributed generation growth, fleet electrification growth, and large customer projects that are informed by customer account managers.

Q21. Can you describe the "wedge" used in the models as a result of the COVID-19 pandemic?

A21. Since March 2020, mitigation strategies to reduce the spread of COVID-19 have caused a shift in electricity consumption throughout DTE Electric's service territory. In general, these mitigation strategies had an inverse effect on Residential and C&I sales. Specifically, Residential sales increased as a result of shelter in place orders and the general population curtailing activities occurring outside of the home. Small C&I sales have decreased due to closures of movie theaters, gyms, bars and restaurants. Large C&I sales also decreased as a result of temporary cessation of manufacturing, limits on large social gatherings such as sporting events, and work from home policies. Due to the nature of some of these policies, historical relationships between economics and energy consumption cannot fully capture the variances associated with the impact of COVID-19.

For example, C&I sales have historically shared a relationship with employment levels in The Company's Service Area. Among other factors, if employment levels increase or decline, C&I sales would follow respectively. However, if an employer elects to move their employees to a remote environment, rather than lay them off, the end-use stock utilization within the C&I building will be reduced with less need for office equipment, HVAC and lighting. Since these employees are still employed, although not physically present, the employment numbers remain unchanged. Thus, there is a decline in C&I electric usage consistent with lower employment levels even though employment has not declined. The regression models cannot fully capture the changing end-use utilization in C&I sales with only employment, creating a need for an additional variable.

Conversely, these sales would be shifted to Residential homes where the work is occurring, driving increases in the utilization of end-use stock at times where it may have not previously been as high, such as running air conditioning at higher levels in the middle of the day.

The wedge aims to capture these unusual changes by beginning with an assessment of daily loads from class and market level Daily Tracking models. Using interval or aggregated hourly data helps provide better clarity in terms of how customers use energy in real time. These models provide insight into how the various customer class electric consumption patterns change from day to day depending on weather, day of the week, and time of year.

In a status quo environment, these Daily Tracking models perform well at forecasting short and medium-term loads. The wedge can be thought of as the percent deviation from these models. Formally, the wedge is calculated as:

$$Wedge = \frac{(Actual\ Load - Baseline\ Load)}{Baseline\ Load} X\ 100$$

Actual load is defined as the observed load by customer class from AMI data, and Baseline load is defined as the "business as usual estimates" from The Daily Tracking models. Business as usual estimates are derived by halting the model's estimation period prior to the effects of the COVID-19 pandemic.

The wedge is explained and forecast through deviations in consumer mobility patterns provided by sources such as Google or The Institute for Health Metrics Evaluation[4]. Since the beginning of the COVID-19 pandemic, Google has provided public access to data that provides insight into changes in consumer behavior in response to policies aimed at combating COVID-19. The data is expressed as a percentage deviation from "normal" or before the start of the COVID-19 pandemic. This data, and the trends present in the history, provides a baseline for forecasting the wedge used in the class level regression models.

The resulting wedge estimates the COVID-19 impact in the history and forecast by customer class or market segment, which is used as an input variable alongside economic, weather and other variables in the long-term forecasting models.

[4]Institute of Health Metrics Evaluation and Google COIVD-19 Community Mobility Reports. Retrieved at https://covid19.healthdata.org/global and https://www.google.com/covid19/mobility/

Q22. What level of Energy Waste Reduction (EWR) is assumed in the forecast?

A22. The load forecast assumes EWR savings to be 2.0 percent starting in 2021 through the forecast horizon. This is consistent with the levels approved in The Company's Integrated Resource Plan filing in Case No. U-20471.

Q23. How was the Distributed Generation outlook applied to the forecast?

A23. The Distributed Generation outlook (encompassing behind-the-meter solar photovoltaics) was developed utilizing the Company's residential and non-residential interconnection history. The Company engaged with ICF Resources LLC (ICF), a global consulting service company, to conduct a market study. ICF produced forecasts of photovoltaic (PV) economics for both residential and C&I customers and estimated the customer PV capacity and electricity output that will be added in DTE Electric's service territory for each year between 2021 and 2030.

In the Residential and Small C&I models, the historical and forecast Distributed Generation is input directly as an end-use into the model. In the Large C&I models, the incremental Distributed Generation is subtracted as a post-regression adjustment.

Q24. How was the Electric Vehicle (EV) outlook applied to the forecast?

A24. For the EV forecast, the cumulative vehicle stock forecast presented by Witness Burns was used as a starting point to estimate the historical and forecasted load in the Company's service territory.

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The EV volume is multiplied by the KWh/vehicle and the assumed vehicle miles traveled unique to each vehicle segment to arrive at the load associated with the forecasted vehicle volumes.

For light-duty vehicles, numerous national studies[5] suggest approximately 80 percent of EV charging is done at personal residences while the other 20 percent is done at non-residential locations, such as workplace or public charging stations. Therefore, 80 percent of the light-duty EV sales forecast was applied to the residential model as an additional end-use. The remaining 20 percent was applied to the Small C&I model as an additional end-use.

For fleet (medium-duty and heavy-duty) vehicles, 100 percent of the fleet EV sales forecast was applied to the Large C&I model as an incremental adjustment to the forecast.

Q25. How was the Electric Choice sales forecast developed?

A25. The Electric Choice sales forecast was based on 10 percent of retail sales. Previous year's class ratios are applied to the Choice cap and new customer load is added separately.

Q26. How was the DTE Electric system peak demand forecast developed?

A26. HELM 2.0 was used to forecast annual peak demand. HELM 2.0 was also utilized to determine monthly peak demands in the forecast period.

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[5] NRDC Electric Vehicle Charging 101 Electric Vehicle Charging 101 | NRDC
JD Power Study: Electric Vehicle Owners Prefer Dedicated Home Charging Stations JD Power Study: Electric Vehicle Owners Prefer Dedicated Home Charging Stations - Forbes Wheels

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Q27. What is HELM 2.0?

A27. HELM 2.0 is an internal model based on the Electric Power Research Institute (EPRI) hourly model. It has been updated to include profiles for each sales class using historical hourly AMI interval data. The Residential and Small C&I classes were broken into base, cooling, and heating end-uses which allowed more detailed modeling than in the past. Annual and/or monthly sales, along with hourly demand profiles for each sales class or end-use, are key inputs into the HELM 2.0 model.

Q28. What temperature assumptions were made regarding the DTE Electric service area and DTE Electric bundled peak demand forecast?

A28. Normal temperature on the day of the annual peak is assumed to be 82.7 F, which is the mean temperature from Detroit Metropolitan Airport. This value is based upon an average peak-day mean temperature for a 15-year period (2006 through 2020). The mean temperature is calculated as the average of the high and low temperature for the day. The peak day is assumed to occur on a weekday in July or August. In addition, normal weather conditions were utilized for the projection of weather-sensitive sales.

Q29. Are Demand Response programs included in the Company's peak forecast?

A29. Demand Response programs are not explicitly included in the peak forecast. Non-dispatchable programs such as time-of-use pricing, is embedded in the historical load-shapes used to forecast the peak demand. However, dispatchable Demand Response programs, such as Interruptible Air Conditioning, are used to meet the Company's required amount of unforced capacity needed to meet the MISO resource adequacy requirements. The dispatchable Demand Response programs are accounted for on the supply side as load modifying resources. For further detail on resource adequacy requirements see the testimony of Company Witness Burgdorf.

Part III: Historical and Current Electric Forecast Sales and Demand

Q30. What has been the compound annual growth rate of DTE Electric sales over the last five years?

A30. As shown in Exhibit A-5, Schedule E1, page 4 of 4, weather normalized service area sales from 2016 to 2020 have declined during the five-year historical period. In 2016, total service area sales were 47,551 GWh and 2020 sales were 44,003 GWh, representing a compound annual growth rate (CAGR) of -1.9 percent, which is a more pronounced decrease than what has been historically seen. In 2019 weather normalized service area sales were 46,222, representing a CAGR of -0.9 percent when comparing 2016 through 2019. The primary reason for the more notable decrease in sales in 2020 is due to business customers shutdown from the coronavirus pandemic.

Bundled sales have decreased from 42,660 GWh in 2016 to 40,256 GWh in 2020, representing a CAGR of -1.4 percent. The electric choice sales declined from 4,892 GWh in 2016 to 3,747 GWh in 2020 by a CAGR of -6.4 percent. Refer to Exhibit A-5, pages 1 through 3 for additional detail regarding historical actual sales for the service area, bundled and electric choice.

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Q31. What has been the CAGR of DTE Electric peak demand over the last five years?

A31. As shown in Exhibit A-5, Schedule E1, page 4 of 4, the service area peak demand in 2016 was 11,332 MW and 2020 peak demand was 11,246 MW, representing a CAGR of -0.2 percent. The bundled peak demand was 10,351 MW in 2016 and 10,578 MW in 2020 at a CAGR of 0.5 percent.

Q32. What are sales for the projected test period, November 2022 through October 2023?

A32. The service area sales for the projected test period, November 2022 through October 2023 are 45,047 GWh and bundled sales are 40,438 GWh. The projected test period service area, bundled, and electric choice sales are displayed in Exhibit A-15, Schedule E1, pages 1 through 3. The projected known and measurable changes for bundled sales from 2020 to the projected test year are detailed in Exhibit A-15, Schedule E3.

Q33. What are the system output and annual peak demand for the projected test period, November 2022 through October 2023?

A33. The service area system output and annual peak demand for the projected test period, November 2022 through October 2023 are 48,427 GWh and 11,158 MW, respectively. The projected test period bundled system output and annual peak demand are 43,548 GWh and 10,341 MW, respectively. The service area and bundled system outputs and peak demand can be found on Exhibit A-15, Schedule E2, pages 1 and 2. The Electric Choice impact is displayed in Exhibit A-15, Schedule E2, page 2 of 2. Ten percent (10%) and 90 percent (90%) confidence

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bands on forecasted summer peak demand is provided for DTE Electric's service area and DTE Electric's bundled sales levels and can be found on Exhibit A-15, Schedule E2, pages 1 and 2.

Q34. Can you summarize how the bundled retail sales forecast and the Electric Choice sales forecast for the projected test period November 2022 through October 2023 compare to the historical period?

A34. In general, electric sales from 2016 through 2019 have declined largely as a result of relatively flat economic growth, combined with increased EWR efforts. In 2020, electric sales were impacted by COVID-19 and the resulting mitigation strategies that came with it. Given that many business customers halted operations, electric sales experienced an exceptionally sharp decline in 2020.

As mitigation strategies continue to subside, electric sales are on a recovering trajectory, specifically, weather-normalized bundled retail sales are forecasted to increase from 40,256 GWh in 2020 to 40,438 GWh in the projected test period. Electric Choice sales are forecasted to increase from 3,747 GWh in 2020 to 4,609 GWh in the projected test period.

Although the trajectory of sales in the projected period is increasing from 2020 electric sales levels, service area sales are projected to remain below 2019 levels, consistent with the decreasing trend in electric sales seen from 2016 through 2019.

Q35. What is the CAGR of the DTE Electric service area electric sales from 2020 through the forecast period to 2026?

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A35. The service area sales are expected to increase to 44,629 GWh in 2026. This represents a 0.2 percent average annual increase. The forecast of annual sales and system output for DTE Electric's service area for the years 2021 through 2026 is reflected on Exhibit A-15, Schedule E1, page 1 of 3.

Q36. What is the CAGR of DTE Electric bundled electric sales from 2020 through the forecast period to 2026?

A36. The bundled sales are projected to decrease over the forecast period, consistent with the declining trend seen in the historical data. The bundled sales are expected to decline to 40,061 GWh in 2026. This represents a -0.1 percent CAGR. The current forecast of bundled sales and system output are shown on Exhibit A-15, Schedule E1, page 2 of 3.

Q37. What is the CAGR of Electric Choice sales from 2020 through the forecast period to 2026?

A37. Electric Choice sales are expected increase to 4,567 GWh in 2026. This represents a 3.4 percent CAGR. The current forecast of electric choice sales and system output are shown on Exhibit A-15, Schedule E1, page 3 of 3.

Q38. What is the outlook for Residential Class sales?

A38. DTE Electric's service area Residential Class sales are forecast to decline 5.2 percent annually, on average, between 2020 and the projected test period in this case and increase by 0.6 percent annually, on average between 2020 and 2026. The sharp decline in sales from 2020 to the test period is due to the artificial increase in 2020 Residential sales as a result of COVID-19, which is expected to reverse by

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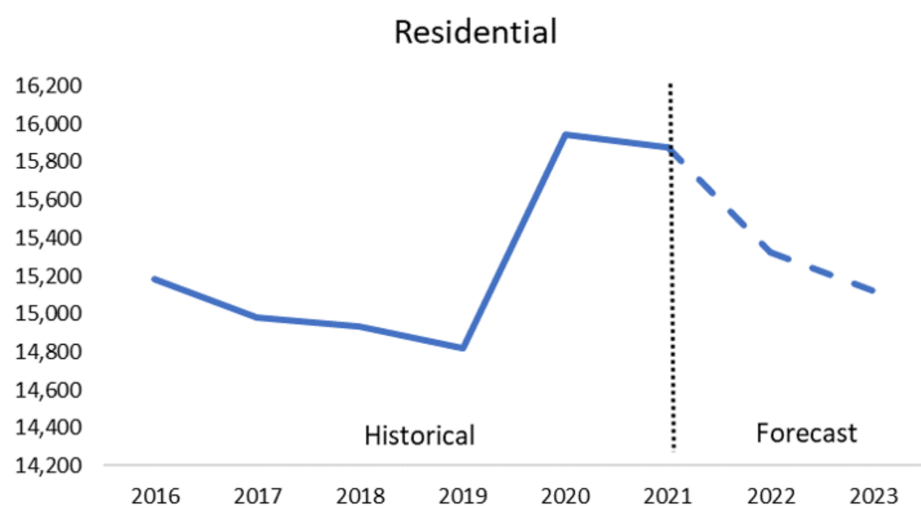
the end of 2022. Modest average annual growth of 0.6 percent in residential customer count is expected through 2026 due to a moderating housing market. However, use-per-customer through 2026 is expected to decrease by 1.2 percent annually on average. This is due to the long-term trend of increases in the saturation of appliances being offset by more efficient electric appliances and the adoption of energy efficient lighting. For a graphical view of the residential forecast, refer to Figure 3 below.

Figure 3



Q39. What is the outlook for Small C&I class sales?

A39. DTE Electric's service area Small C&I class sales are forecast to increase 6.9 percent annually, on average, between 2020 and the projected test period. Small C&I class sales are forecast to increase by 0.9 percent annually, on average between 2020 through 2026. The sharp increase in sales is due to a strong economic recovery reversing the lower sales seen in Small C&I in 2020 due to COVID-19. Modest average annual growth of 0.7 percent in Small C&I customer count is expected through 2026 due to Residential customer growth. Use-per-customer through 2026 is expected to increase by 0.3 percent annually on average. Growth in the Small

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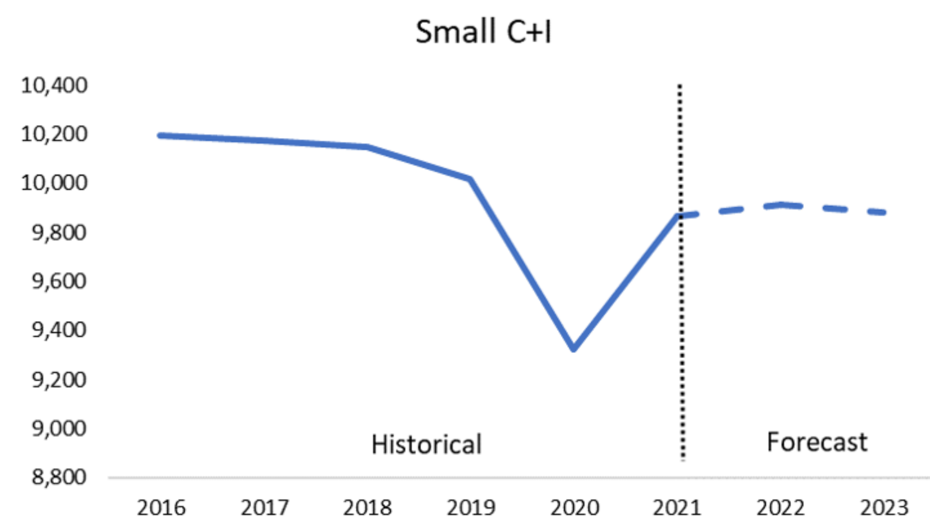
C&I class is also constrained by the increase of energy efficiency programs targeting Commercial and Industrial customers. For a graphical view of the small C&I forecast, refer to Figure 4 below.

Figure 4



Q40. What is the outlook for Large C&I class sales?

A40. DTE Electric's service area Large C&I class sales are expected to increase by 6.7 percent annually on average from 2020 to the projected test period in this case. The Large C&I class sales will increase 0.6 percent annually, on average, from 2020 through 2026. Because Large C&I sales move so robustly with conditions of the local economy, it is necessary to understand the differences in near term and long-term growth rates.

Known and measurable events that result in a decline within the short-term were incorporated into the modeling, which includes a new natural gas cogeneration facility at a university. The changes are found on Exhibit A-15, Schedule E3. Economic activity is expected to return to more stable levels in the mid to long-

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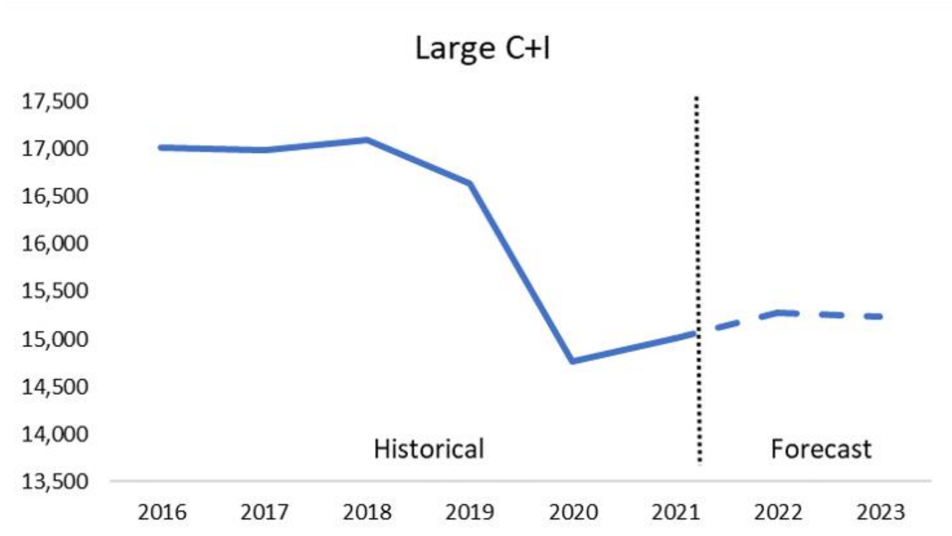
term, which, based on historical trends, would cause the Large C&I class sales to stabilize as well. As mentioned previously, Large C&I class sales are allocated between seven supersector markets: education and health, trade, transportation, and utilities (TTU), offices, other markets, automotive, steel and other manufacturing.

Annually, on average, from 2020 through 2026, the education and health supersector is expected to decrease by 0.4 percent due to energy efficiency efforts pressing down on sales. The TTU supersector is projected to decrease 2.1 percent annually, on average, through 2026 due to a decrease in TTU employment and energy efficiency. The office supersector is forecasted to increase 0.6 percent due to an increase in employment and people returning to the office. The other markets supersector is forecasted to increase 2.5 percent due to an increase in other services employment.

Automotive sales will increase 1.1 percent annually, on average, from 2020 through 2026. The increase in automotive sales is mostly due to increased production and an increase in manufacturing employment. However, other manufacturing sales are projected to decrease 0.4 percent annually, on average, from 2020 through 2026. The slight reduction in sales is driven by increased energy efficiency initiatives outweighing the increase in production and manufacturing employment for this sector. Steel sales will increase 2.8 percent annually, on average, from 2020 through 2026 as primary metal employment continues to increase. For a graphical view of the large C&I forecast, refer to Figure 5 below.

Figure 5



Q41. What is the outlook for Other Class sales?

A41. DTE Electric's service area Other Class sales are expected to decrease 1.6 percent annually, on average, from 2020 through 2026. The Other Class consists of street lighting and traffic signals. The main reason for the decline in sales is the use of more energy efficient lighting. For further detail on street lighting see the testimony of Company Witness Bellini.

Q42. What is the CAGR of the DTE Electric service area system peak demand from 2020 over the forecast period to 2026?

A42. As shown in Exhibit A-15, Schedule E2, page 1 of 2, DTE Electric's temperature normalized service area peak demand declines from 11,246 MW in 2020 to 10,981 MW in 2026, representing a CAGR of -0.4 percent. The decline in peak demand

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is mainly due to a decline in residential air-conditioning electricity sales, which is 2.1 percent on average annually, due to improvements in energy efficiency.

Q43. What is the CAGR of the DTE Electric bundled peak demand from 2020 over the forecast period to 2026?

A43. DTE Electric's bundled peak demand forecast declines to 10,169 MW in 2026, an average compound annual growth rate of -0.7 percent. The bundled peak demand forecast from 2021 to 2026 is shown in Exhibit A-15, Schedule E2, page 2 of 2.

Part IV: Electric Load Forecast Accuracy

Q44. How were the sales forecast and methodologies validated?

A44. DTE Electric's service area sales forecast is tracked annually for metrics purposes. The Company continuously checks the accuracy of the sales forecast models. For example, as shown in Exhibit A-15, Schedule E5, page 1, the DTE Electric total service area forecast in 2019 was 47,081 GWh. Total weather-normalized service area sales in 2019 were 46,222 GWh. This represents a 98.2 percent accuracy of the 2019 total sales forecast. On average, for historical years 2016 through 2019, the absolute percent variance for the total sales forecast is 0.77 percent using the Company's forecasting methods, as shown in Exhibit A-15, Schedule E5, page 1.

The Company also assesses the accuracy of the individual forecast models. For example, the DTE Electric Residential service area forecast in 2019 was 14,910 GWh. Weather-normalized Residential sales in 2019 were 14,820 GWh. This represents a 99.4 percent accuracy of the 2019 forecast. On average, for historical

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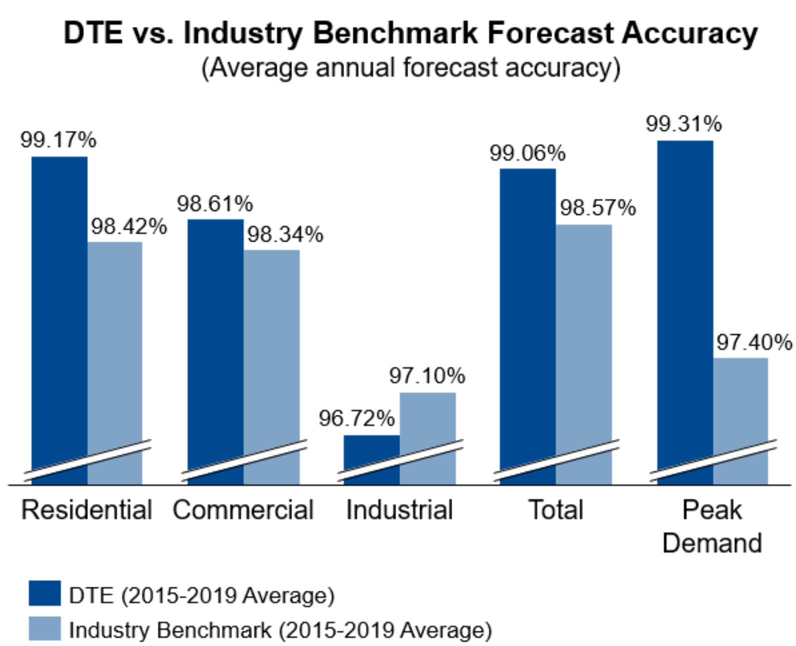
years 2016 through 2019, the absolute percent variance for the Residential sales forecast using the Company's Residential forecast method is 0.83 percent, as shown on Exhibit A-15, Schedule E5, page 1. The forecast accuracy achieved validates DTE's forecast methodology.

Q45. Does the Company perform any benchmarking on forecast accuracy?

A45. Yes. The Company conducts benchmarking activity by researching forecast accuracy studies. A study, conducted by ITRON in 2020, found the average absolute percent variance among peer utilities in total for years 2015 through 2019 is 1.4 percent, as shown in Exhibit A-15, Schedule E5, page 2, while DTE's average is 0.9 percent. DTE Electric achieves better accuracy than peer utilities across the nation in forecasting various customer classes, total sales, and peak demand, as shown in Figure 3 below.

Figure 6 DTE Electric vs. ITRON Forecast Accuracy Benchmark



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Q46. Does this complete your direct testimony?

A46. Yes, it does.