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August 16, 2024

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-21534

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter are DTE Electric Company's Rebuttal Testimony and Exhibits of Witnesses, Morgan Elliott Andahazy, Robert A. Bellini, Pina Bennett, Shawn D. Burgdorf, Jeffrey C. Davis, Satvir S. Deol, Keegan O. Farrell, Matthew A. Fix, Neal T. Foley, Margaret E. Guillaumin, Shannen M. Hartwick, Michael J. Hatsios, Brian L. Hill, Jerome K. Hooper, Allen J. Kryscynski, Timothy J. Lepczyk, Habeeb J. Maroun, Pankaj Sharma, Jason E. Sparks, Rachel C. Steudle, Theresa M. Uzenski, Bente Villadsen, Aaron Willis, and Sherri L. Wisniewski. Also attached is the Proof of Service.

In addition, Mr. Bellini's Exhibit A-40, confidential Schedule EE5, Mr. Deol's Exhibit A-50, CEII confidential Schedule OO2, Ms. Elliott Andahazy's Exhibit A-51 confidential Schedules PP2, PP4, PP6, PP8, and PP10, Ms. Hartwick's Exhibit A-53 CEII confidential Schedule RR2, and Mr. Kryscynski's Exhibit A-43 public and CEII confidential Schedule HH4 will be filed under seal with the Commission. The confidential exhibits and the confidential schedules will be sent to the persons who have signed the appropriate Non-Disclosure Certificate associated with the Protective Order issued in this proceeding. In addition, the following exhibit schedules contain voluminous models available by links: Exhibit A-51, Schedule PP10, Exhibit A-53, Schedule RR2, Exhibit A-43 Schedules HH4 and HH5. The confidential exhibit schedules and voluminous exhibit schedules are being provided to the respective parties via the following secure portal links listed below:

Public Portal Link:

<https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U21534/Documents/Forms/AllItems.aspx>

Confidential Portal Link:

<https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U21534/Protected%20Responses/Forms/AllItems.aspx?viewid=3a3b1cf5%2D351a%2D48f8%2Da89d%2D7d7d9146e197>

CEII Portal Link:

<https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U21534/U21534%20Rebuttal/Forms/AllItems.aspx>

Very truly yours,

Jon P. Christinidis

Digitally signed by Jon P.
Christinidis
Date: 2024.08.16 19:15:34 -04'00'

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-21534

REBUTTAL TESTIMONY

OF

ROBERT A. BELLINI

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF ROBERT A. BELLINI

Line
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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

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

6
7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal is to rebut the following intervenor positions:

14

15 Michigan Municipal Association for Utility Issues (MI-MAUI), Witness Bunch

16 1) Proposal that CIAC be discontinued for HID-LED group/project
17 conversions

18 2) Proposal to create a bill credit scheme designed to issue future credits to
19 early LED adopters

20 3) Proposal to adjust the E1 streetlighting sales forecast by 3,308,045 kwh,
21 equivalent to 4.06% of unadjusted forecast

22 4) Proposal that the Company be disallowed recovery of its post painting and
23 inspections costs

24 5) Proposal to disallow spending on the Company's underground capital cable
25 replacement program

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- 1 6) Proposal to include streetlighting capital and distribution O&M plans in its
2 Distribution Grid Plan
3 7) Recommended creation of additional reports providing taxonomy of root
4 cause outages, causes of delays in restoration, cost breakdowns, and other
5 data
6 8) Proposed cumulative disallowance of either \$7,705,567 or \$5,833,539
7 based on the claim that the Company is unreasonably spending on
8 excessively bright LEDs
9 9) Recommendation that the Company be ordered to implement full cost-of-
10 service rates

11

12 City of Ann Arbor, Witnesses Naheedy & Stults

- 13 10) Assertion that Company restoration performance continues to be poor
14 11) Assertion that Ann Arbor stocking a 58W LED with a lower color
15 temperature as “special order material” is unreasonable
16 12) Assertion that Ann Arbor was financially disadvantaged as a result of HPS
17 now being replaced with equivalent LEDs upon their failure, noting that
18 they’d have paid nothing if they waited for each HPS to fail
19 13) Proposal that Ann Arbor should receive a bill credit in recognition of the
20 City paying for the conversion of other customers making the transition
21 from HID to LED fixtures

22

23 **Recommendations**

24 **Q4. Please summarize your conclusions, recommendations, and Company**
25 **positions to the Commission.**

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1 A4. My summary of conclusions, recommendations, and Company positions are
2 outlined below:

3 MI-MAUI Proposals/Assertions

4 1) The Commission should continue to reject (as it has in the past) MI-
5 MAUI's recommendation to discontinue CIAC charges for LED upgrades.
6 The existing CIAC approach, approved by the Commission for converting
7 company-owned mercury vapor (MV) lights to LEDs, remains valid. This
8 method, which includes the now outdated high-pressure sodium (HPS)
9 lights, should continue in line with the established practice for mercury
10 vapor (MV) light replacements, as both MV and HPS are categorized as
11 HID.

12
13 2) MI-MAUI's recommendation to create a bill credit scheme designed to
14 refund CIAC to customers that converted lighting systems to LEDs should
15 be dismissed. Refunding past years of previously customer funded CIAC
16 is unwarranted, inconsistent with previously Commission-approved policy,
17 and would have an adverse effect on all municipal streetlight customer rates
18 given that the LEDs now represent almost 70% of all company-owned
19 municipal streetlights.

20
21 3) The Company agrees with MI-MAUI's proposal to adjust the sales forecast
22 based on the 2023 night patrol outage results for the incremental difference
23 of 0.81% (4.06% based on 2023 night patrol outages less 3.25% ordered in
24 U-21297). However, as the night patrol program evolves, it will target
25 communities with higher outage percentages. Therefore, annual results will

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1 become less of a proxy for system-wide outages. The Company
2 recommends the Commission order it to work with Staff and MI-MAUI to
3 establish a methodology that provides for a long-term, sustainable approach
4 to approximate system wide outages.

5

6 4) The Company recommends that the Commission deny MI-MAUI's
7 proposed disallowance for post painting and post inspections or conversely,
8 approve recovery over the same time period for the Company's under-
9 recovery of outage maintenance costs.

10

11 5) The Commission should reject MI-MAUI's proposal to disallow the
12 Company's recovery of its underground capital cable replacement program.
13 Witness Bunch's claim that the Company has not provided reliability or cost
14 data to justify this program is incorrect. All of the underground replacement
15 projects completed since program inception were data driven and resulted
16 in avoidance of future outage events.

17

18 6) The Commission should reject the proposal that Community Lighting
19 capital investment costs for its underground cable replacement program and
20 other O&M costs be included as part of DTE's Distribution Grid Plan
21 (DGP). The focus of the DGP is specific to distribution investments, and
22 were never intended to encompass Community Lighting infrastructure.
23 Community Lighting's assets/rate base, system of operations, and
24 investments are distinctly different than that of DTE's distribution system
25 and are appropriately excluded from the DGP.

26

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- 1 7) The Commission should reject MI-MAUI's proposal requiring the
2 Company to create a variety of new reports with criteria ranging from a
3 taxonomy of root cause outages, causes of delays in restoration, cost
4 breakdowns, and other data for two reasons. First, the proposal is based on
5 a false premise that the Company's outage performance continues to
6 deteriorate, which it has not. Second, Witness Bunch incorrectly overstates
7 the capabilities of the Company's new outage management system,
8 Kloudgin. I recommend the Commission order the Company, Staff, and
9 MI-MAUI work together to review the Company's system reporting
10 capabilities.
- 11
- 12 8) MI-MAUI's recommended cumulative disallowance pertaining to HID-
13 LED conversions of either \$7,705,567 or \$5,833,539 based on its claim that
14 the Company unreasonably spent on excessively bright LEDs should be
15 dismissed for two reasons. First, Witness Bunch's only basis for asserting
16 the Company selected over lit LEDs and in calculating this disallowance,
17 was a vendor (Leotek) LED crossover chart that has since been disavowed
18 by the vendor and is no longer supported or available. Second, the Company
19 engaged two lighting industry experts the purpose of which was to analyze
20 and opine on the Company's LED selection methodology when replacing
21 existing customer HID lights through project conversions. Both industry
22 experts independently concluded that DTE's methodology for selecting
23 LEDs was reasonable and appropriate.

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1 9) Similar to its position during Case No. U-21297, the Company does not take
2 a position on MI-MAUI's recommendation to order the Company to
3 implement full-cost-of service rates, but instead provide information to the
4 Commission in making a prudent decision on whether to continue using the
5 current design methodology while considering the interests of all rate
6 payers.

7

8 Ann Arbor Proposals/Assertions

9 10) Witness Naheedy incorrectly claims that the Company's outage restoration
10 performance continues to be poor and bases his conclusion on his
11 predecessor's testimony presented during Case No. U-20836 two years ago
12 which stated that DTE's outage rate was 26%. To the contrary, the
13 Company has conducted 8 night patrols that canvassed all of Ann Arbor's
14 company-owned municipal streetlights between 2020 – 2023. The outage
15 results from these 8 patrols ranged from 2% to 6%.

16

17 11) Ann Arbor incorrectly concludes that having to stock a 58W LED with a
18 lower color temperature as "special order material (SOM)" is unreasonable.
19 The Company's standard stock 58W LED fixture is 4000 CCT. ANSI/IES
20 RP-8-22 notes a "practical difference for 4000K, which had greater
21 detection distances especially for pedestrians, than any of the other light
22 sources." The City's 3000 CCT 58W LED therefore does not align with
23 ANSI/IES RP-8.

24

25 12) Ann Arbor Witness Naheedy inaccurately concludes that Ann Arbor was
26 financially disadvantaged as a result of the Company now replacing HPS

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1 fixtures with its standard stock LED fixtures. This assertion is incorrect for
2 two reasons. First, Ann Arbor selected to sample a 58W LED fixture with
3 a 3000 CCT, whereas the Company's standard stock LED replacement is a
4 58W 4000 CCT fixture.

5
6 Second, Ann Arbor (and MI-MAUI above) incorrectly frames the
7 Company's extension of its current methodology in replacing obsolete MV
8 fixtures that fail with LEDs to it now including replacing obsolete HPS
9 fixtures that fail with LEDs. Both MV and HPS are lighting technologies
10 that are no longer available. This is not a new policy or methodology, but
11 instead an extension of an already Commission-approved methodology that
12 has been employed since 2017.

13

14 13) The Commission should dismiss Witness Stults proposal (similar to MI-
15 MAUI's bill credit proposal) that the City receive a bill credit in recognition
16 that they are paying for the conversion of other customers making the
17 transition from HID to LED fixtures. If Witness Stults proposal were to
18 be adopted, millions of dollars would be added to the municipal
19 streetlighting rate base (70% of company-owned streetlights are now LEDs)
20 which would result in higher rates.

21

22 **Q5. Are you sponsoring any exhibits in this proceeding?**

23 A5. Yes. I am sponsoring the following exhibits:

24	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
25	A-40	EE1	Isakson Rebuttal Testimony Consumers U-21389
26	A-40	EE2	U-21534 MAUIDE-4.28b 2019-2023 O&M Spend

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1	A-40	EE3	Riverview Capital Cable Replacement Job
2	A-40	EE4	U-20147 DGP Excerpt
3	A-40	EE5	NDA MAUIDE-5.48 Leotek Removal of Crossover
4			Chart Correspondence
5	A-40	EE6	2023 FHWA Lighting Handbook Excerpt
6	A-40	EE7	2023 FHWA Excerpt – Lighting Level
7			Recommendation
8	A-40	EE8	Revised 100W HPS Analysis With LLF
9	A-40	EE9	U-21534 DEMAUI-2.1 (DEMAUI-4)
10	A-40	EE10	U-21534 DEMAUI-6 U-18322 Witness Miller
11			Excerpt
12	A-40	EE11	U-21534 DEAA-2.1bi – DEAA-2.1ci

13

14 **Q6. Were these exhibits prepared by you or under your direction?**

15 A6. Yes, they were.

16

17 **Q7. Are there any aspects of testimony provided by MI-MAUI and the City of Ann**
 18 **Arbor not specifically addressed in your rebuttal testimony?**

19 A7. Yes, the absence of a discussion of other matters discussed in both the MI-MAUI
 20 and Ann Arbor direct testimonies is not an indication that I agree with the
 21 information provided or arguments presented. Considering the substantial
 22 discussion involving the various aspects of my testimony, and the limited time
 23 available to respond, I have focused my rebuttal testimony on the most significant
 24 areas of disagreement.

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1 **REBUTTAL OF MI-MAUI WITNESS BUNCH**

2 **DISCONTINUATION OF CIAC FOR GROUP/PROJECT CONVERSIONS AND**

3 **FUTURE CREDITS FOR EARLY LED ADOPTERS**

4 **Q8. Do you agree with Witness Bunch's statement on page 21, lines 7-9 of his direct**
5 **testimony that "[t]here is no justification to charge CIAC for a customer-**
6 **requested project that will be cheaper for the Company to implement than if**
7 **the customer did nothing and thus reactive conversions were the way every**
8 **light in the City were addressed."**

9 A8. No. Witness Bunch inappropriately conflates two separate and distinct,
10 longstanding Commission supported processes as it pertains to both reactive
11 conversions and customer requested projects specific to HID replacements, in
12 justifying the elimination of customer CIAC.

13 The Company's proposed change when replacing through reactive conversions
14 upon failure, high pressure sodium (HPS) lights due to their obsolescence with
15 LEDs, is very much consistent with how the Company currently addresses mercury
16 vapor (MV) in-service failures. When responding to a MV light failure, the
17 Company will replace it with its equivalent LED fixture at no cost to the customer.
18 For customer-requested conversion projects, customer CIAC has been a long-
19 standing Commission-supported practice, the intent of which is to not socialize the
20 cost of a project that benefits a single customer, to all other customers within that
21 rate class.

22

23 **Q9. You stated that your proposed change to replace HPS fixtures upon failure**
24 **with an equivalent LED is not a departure, or new methodology employed by**

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1 the Company, but instead follows the same Commission-approved
2 methodology when replacing MV fixtures upon failure. Can you elaborate?

3 A9. Yes. As I explained on page 7, lines 10 - 17 in my direct testimony in the instant
4 case, “Pursuant to the Energy Policy Act of 2005, Mercury Vapor lamps became
5 obsolete” and “DTE Electric began to convert failed MV lighting to LED for E1
6 Option I customers starting in 2017 in accordance with the Commission’s order on
7 January 31, 2017, in Case No. U-18014.” (emphasis added). HPS technology has
8 now reached the same point of de-facto obsolescence as its MV counterpart. This
9 is a continuation of long-standing policy to allow those customers who have chosen
10 to keep the lighting system they and their community members are comfortable
11 with, regardless of lighting technology type.

12

13 **Q10. Is Witness Bunch correct in stating on page 23, lines 4-10 that this policy**
14 **change “...seems like an effort by DTE to entice customers to rush into a**
15 **process that will result in those customers covering the project costs for**
16 **converting from HID’s to LED’s when they would not have to pay hundreds of**
17 **thousands – or even millions – of dollars up front for that conversion if they**
18 **just waited for their existing lights to fail?”**

19 A10. No. As shown in “Table 3: E1 Option I Light Counts by Type” on page 8, line 12
20 of my direct testimony, there are still 10,695 MV municipal streetlights still in
21 service, or 6% of our total municipal lights owned, operated and maintained by
22 DTE. It is telling however, that even with grant funding offered by the Southeast
23 Michigan Council of Governments (SEMCOG) to offset approximately 80% of the
24 total cost of streetlight conversion project, municipal customers representing only

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1 11,000 of the approximately 52,000 (MV+HPS+MH)¹ remaining HID lights opted
2 take advantage of this grant. Further, DTE reached out to all of its non-LED
3 customers when the SEMCOG grant program in an effort to make the “aware and
4 assisted several communities to complete their applications.”²

5

6 **Q11. Has Witness Bunch recommended Customer CIAC be eliminated or taken**
7 **contradictory positions on the application of CIAC in prior rate case**
8 **proceedings?**

9 A11. Yes, both. This is the 3rd consecutive rate case in which Witness Bunch has
10 advocated for the elimination of CIAC. As noted on page 476 of Order U-20836,
11 DTE participated in the Staff facilitated CIAC workgroup held in early 2023, in
12 which MI-MAUI/Ann Arbor advocated to have conversion costs excluded from
13 CIAC. Witness Bunch again argued in Case No. U-21297, that CIAC for HID –
14 LED conversions be eliminated because “...customers who paid for past
15 conversion will be able to recover their investment³” The Commission in its order
16 correctly stated that it “...agrees with the ALJ and declines to adopt new calculation
17 methods for CIAC. Here too (and as discussed in the Cost of Service section of
18 this order, below) the Commission is not persuaded to adopt MI-MAUI’s proposal
19 to end the CIAC charge. The Commission finds that the CIAC charge remains
20 applicable to this conversion work.”⁴

21 Interestingly, Witness Bunch took the opposite position during Consumers Case
22 No. U-21389, in which he advocated that customers be charged the full cost of new

¹ Bellini U-21534 Direct Testimony, page 8, line 12 “Table 3: E1 Option Light Counts by Type”

² Bellini U-21534 Direct Testimony, page 7, line 24

³ U-21297 MI-MAUI exceptions, p.4

⁴ Order U-21297, Page 139

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1 streetlighting installations.⁵ As Staff Witness Isakson pointed out in his rebuttal
2 testimony (Exhibit A-40, Schedule EE1), Mr. Bunch contradicted himself when
3 testifying in concurrent DTE Electric and Consumers cases, U-21297 & U-21389,
4 respectively. When asked if Mr. Bunch took contradictory positions, Staff Witness
5 Isakson stated “Yes. In DTE’s electric rate case U-21297, MI-MAUI advocated for
6 the elimination of CIAC charges for the conversion to LED lights. In that case MI-
7 MAUI argued that the basic reason to assess a CIAC fee was if the customer
8 receives a special service or benefit then other customers should not have to pay for
9 it through rates.⁶”

10

11 **Q12. Please summarize your position on Witness Bunch’s proposal to eliminate**
12 **CIAC for planned conversions and recommendation to the Commission.**

13 A12. Witness Bunch has introduced no new evidence that demonstrates the Company
14 has departed from Commission-approved CIAC practices related to HID-LED
15 conversions. Bunch contends that the sunseting of HPS has created a new and
16 unique inequity for early adopters and those municipal customers that continued to
17 proactively convert their systems to LED. This simply is not true. Similar to the
18 Company’s approach to MV, the Company proposes to replace failed luminaires
19 identified through reactive maintenance with an equivalent LED fixture, and for
20 those proactive HPS – LED conversion projects that municipalities decide to move
21 forward with, we propose to “offer a HPS per light labor credit starting in 2024 for
22 those municipalities that have decided to proactively convert to LEDs for which
23 projects have not yet begun.⁷”

⁵ Bunch U-21389 Direct Testimony, page 7, line 21 – page 8, line 7

⁶ Exhibit A-40 Schedule EE1 Isakson Rebuttal Testimony Consumers U-21389, page 23, lines 1-7

⁷ Bellini U-21534 Direct Testimony, page 11, lines 18-19

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1 Second, as has been argued in prior rate cases, the discontinuation of CIAC would
2 result in the Company absorbing full project conversion costs into rate base, that
3 would be socialized among all E1 Option I municipal customers. As a quick
4 example, if the Company were then required to convert all remaining 40,000 HPS
5 lights without customer CIAC, it is likely those conversion costs would result in
6 absorption into rate base, between \$15M - \$20M depending on the cost of materials
7 and labor at the time of conversion.

8 Therefore, the Company recommends that the Commission again reject MI-
9 MAUI's proposal requiring the Company to stop charging CIAC for project
10 conversions.

11

12 **Q13. In conjunction with Witness Bunch's proposed discontinuation of CIAC, he is**
13 **also proposing that "the Commission instruct DTE a bill credit method...and**
14 **to consult with staff and intervenors in the development of its proposed credit**
15 **scheme in advance of its next filing.⁸" Do you agree with this credit scheme**
16 **proposal?**

17 A13. No. This appears to be an attempt to circumvent the Commission's previous
18 positions in both DTE and Consumers prior rate case filings in which they have
19 affirmed the appropriateness of customer CIAC pertaining to proactive customer
20 HID-LED conversions. As I mentioned in the previous section, Mr. Bunch has
21 introduced no new evidence indicating the Company has deviated from its
22 Commission approved CIAC methodology.

23 As discussed in prior Company rate case proceedings, credits paid to municipal
24 customers who've already made the choice to convert over the past several years

⁸ Bunch U-21534 Direct Testimony, page 29, lines 1-4

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1 would result in millions of dollars being rate based and socialized among all
2 customers. Add to that, the cost to convert the remaining 40K HPS customers as I
3 mentioned previously, would see rates go exponentially higher for the entire
4 municipal customer class.

5 Highlighting the impact to customers that a credit scheme would have, I again turn
6 to Staff Witness Isakson's rebuttal to MAUI's credit proposal in Consumers case
7 U-21836, to eliminate all CIAC charges assessed to streetlighting customers and
8 provide a customer "CIAC offset credit."⁹ Isakson concludes, "It is unclear who
9 would pay the expense related to 9.4 years of tariff payments that represent MI-
10 MAUI's CIAC offset credit. Logically, the revenue shortfall created by issuing
11 MI-MAUI's proposed CIAC credit would be paid for by all lighting customers."¹⁰

12

13 **Q14. You noted that the Commission has rejected Witness Bunch's prior proposals**
14 **to eliminate customer CIAC for HID-LED conversions but indicates in his**
15 **direct testimony that "Consumers worked out a system of time-limited bill**
16 **credits that protect early-mover LED customers against the rate impacts of**
17 **those later no-CIAC conversions."¹¹ Why does Consumers provide this credit**
18 **if the Commission has repeatedly rejected MAUI's proposals?**

19 A14. Unfortunately, Mr. Bunch failed to provide any context in his direct testimony as
20 to what gave rise to Consumers bill credit mechanism, and only chose to present
21 the model itself. He did not provide the contextual definition for "early-mover LED
22 customers"¹² referenced in prior Consumers case U-20697. This model should be
23 disregarded by the Commission.

⁹ Exhibit A-40 Schedule EE1 Isakson Rebuttal Testimony Consumers U-21389, page 22, line 10

¹⁰ Exhibit A-40 Schedule EE1 Isakson Rebuttal Testimony Consumers U-21389, page 22, lines 10-12

¹¹ Bunch U-21534 Direct Testimony, page 26, lines 11-13

¹² Bunch U-21534 Direct Testimony, page 26, line 12

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1

2 **Q15. Were you able to identify any information from prior Consumers rate case**
3 **filings that would provide insight into the definition of an “early-mover LED**
4 **customer” and whether it would have a consistent application to DTE**
5 **municipal LED customers as presented here by Witness Bunch?**

6 A15. Yes. In reviewing MI-MAUI’s DEMAUI-6 discovery response, an “early-mover
7 LED customer” as referred to in Consumers Case No. U-20697 can generally be
8 defined as a municipal customer who proactively installed and “paid to convert
9 their streetlights to a LED technology prior to the Commission order approving the
10 burnout replacement program in Case No. U-18322.¹³” I will assume that this is
11 Mr. Bunch’s reference to an early-mover LED customer. At the heart of the matter
12 in the Consumers case, there are two issues. First, it appears from Witness Bunch’s
13 revised public direct testimony in Case No. U-20697, that Consumers had
14 previously charged customer CIAC upon HPS fixture failure prior to the
15 Company’s policy change to no longer charge CIAC as part of their burnout
16 replacement program. Second, Bunch notes that customer installed, first generation
17 LEDs have a much shorter life (15 years), than do the Company’s (referring to
18 Consumers Energy) preferred model (24 years). Witness Bunch’s proposed
19 Consumers bill credit sought to rectify both the difference in Company installed
20 LEDs with a longer life, and the shift in policy change in Consumers deciding to
21 no longer require CIAC upon failed fixtures. The contention being, had the
22 customer done nothing and let the fixture burn out, they would have received an
23 LED with a longer life at no cost.

¹³ Exhibit A-40 Schedule EE10 U-21534 DEMAUI-6 U-18322 Witness Miller Excerpt

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1 **Q16. Is there a parallel between Consumers bill credit for “early-movers” and DTE**
2 **installing LEDs upon failure of an HPS fixture?**

3 A16. No. As I have mentioned previously, similar to MVs becoming obsolete and being
4 replaced upon failure with an LED, HPS fixtures are being sunset by most lighting
5 manufacturers. Therefore, the DTE is similarly extending the same LED
6 replacement practice to HPS fixture failures. Second, DTE has not changed its
7 CIAC policy as was the case with Consumers. Therefore, the circumstances that
8 led to Consumers bill credits to its early-mover LED customers did not occur here,
9 has no bearing on this issue, and therefore are not relevant in this proceeding.

10

11 **Q17. What is your recommendation to the Commission regarding MI-MAUI’s**
12 **proposed bill credit scheme?**

13 A17. As I mentioned above, in addition to the circumstances that gave rise to Consumers
14 bill credit program having no relevance here, this scheme would have a significant
15 and adverse impact on customer rate design. We are at nearly 70% LED
16 penetration for municipal streetlights.¹⁴ Unwinding and providing credits to LED
17 customers would result in millions of dollars of increased rate base. As such, the
18 Commission should reject MI-MAUI’s credit scheme proposal.

19

20 PROPOSED ADJUSTMENT TO E1 STREETLIGHT SALES FORECAST

21 **Q18. Witness Bunch proposes two input value adjustments (a third being the total,**
22 **unadjusted electric sales forecast for which Mr. Bunch does not recommend**
23 **any changes) to the Company’s sales forecast which include “the Night Patrol**

¹⁴ Bellini U-21534 Direct Testimony, page 8, line 12 “Table 3: E1 Option Light Counts by Type”

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1 **outage rate...and, the number of HID fixtures remaining under the E1, Option**
2 **I rate.¹⁵ Do you agree with these proposed adjustments?**

3 A18. Generally, yes. My recommendation to the Commission is specific to using the
4 night patrol outage rate as a continuing proxy for total system outages. As I note in
5 my direct testimony, "...depending on prior patrol results and repair detail (i.e.
6 large percentage of outages noted in a single municipality or high concentration of
7 outages in a specific area), the Company may adjust the timing of the next
8 scheduled night patrol.¹⁶" This means that as our night patrols become more
9 targeted to those communities that are experiencing higher than average outage
10 events, this has the potential to skew the % of lights canvassed in a given year,
11 higher. In other words, this is less of a representative sample as we continue to
12 target specific communities. I would recommend that the Commission order the
13 Company to work with Staff and MI-MAUI to establish a reasonable and more
14 refined methodology that provides a closer representation of Company owned,
15 municipal streetlight outages.

16

17 **Q19. Does the Company's Sales Forecast already include an adjustment for non-**
18 **working lights?**

19 A19. Yes. The Company has already reduced its sales forecast by 3.25% as ordered by
20 the Commission in Case No. U-21297. Therefore, the proposed adjustment to the
21 Company's sales forecast of 4.06% should only reflect the incremental difference
22 of 0.81%.

¹⁵ Bunch U-21534 Direct Testimony, page 33, lines 7-16

¹⁶ Bellini U-21534 Direct Testimony, page 15, lines 18-20

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1 PROPOSED DISALLOWANCES TO BOTH STREETLIGHTING & PAINTING

2 **Q20. In reference to streetlight post inspections and post painting, Witness Bunch**
3 **states that he is concerned that “...the Company has a history of vastly over-**
4 **collecting for this area.¹⁷” Do you agree with this statement, and is it presented**
5 **in the proper context as compared to other O&M spend areas?**

6 A20. Witness Bunch does correctly state the Company’s as-filed position as it pertains
7 to its anticipated reduction and taken into account in the instant case, for spend for
8 both inspections and post painting. The Company does anticipate lower pole
9 inspection activity now that streetlight-only wood poles are being identified for
10 replacement through Distribution’s pole-top maintenance program, and a lower
11 painting spend due to the use of one painting contractor. Where I disagree with Mr.
12 Bunch is the narrow presentation of approved spend versus actual spend for only
13 these two programs. Mr. Bunch presents a simple table on page 35, line 1 of his
14 direct testimony, that compares Commission-approved spend for calendar years
15 2022 and 2023 (Orders U-20561 & U-20836, respectively) that shows the
16 Company’s spend was \$271K and \$384K less than approved for both programs for
17 each year. I have modified Witness Bunch’s table (see Table 1 below) to include
18 for calendar years 2022 and 2023 to include net O&M spend¹⁸:

¹⁷ Bunch U-21534 Direct Testimony, page 34, line 8

¹⁸ Exhibit A-40 Schedule EE2 MAUIDE-4.28b 2019-2023 O&M Spend

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Table 1 - Updated Company O&M Spend – Inspections/Painting/Outage Maintenance

	CY 2022/U-20561		CY 2023/U-20836	
Approved Spend				
(Inspection + Painting)	\$	489,000	\$	486,580
Actual Spend	\$	218,005	\$	102,886
Difference	\$	270,995	\$	383,694
Approved Net O&M				
Outage Maintenance	\$	1,355,786	\$	1,027,224
Actual Spend	\$	1,943,409	\$	1,980,819
Difference	\$	(587,623)	\$	(953,595)
Total Difference when including Outage	\$	(316,628)	\$	(569,901)

2

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4

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6

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9

10 **Q21. Witness Bunch also recommends that the Company “file as part of their next**
 11 **rate case a report on actual costs with amounts recovered in rates, looking**
 12 **back 5 years.¹⁹” Do you agree with this proposal?**

13 A21. No, I do not. As I stated previously, isolating specific areas of Commission-
 14 approved spend to actuals can be misleading. Similar to budgeting and forecasting,
 15 Company projections are snapshots in time that are based on information available
 16 at that time. There will be variances both favorable and unfavorable when actual
 17 costs are incurred, as was the case for post painting, post inspections, and as the

¹⁹ Bunch U-21534 Direct Testimony, page 36 line 23 – page 37 line 1

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1 Company included here, O&M outage spend. Mr. Bunch's presentation and
2 interpretations drawn were based on an incomplete set of facts and therefore do not
3 support valid conclusions.

4 Therefore, I recommend that the Commission reject both MI-MAUI's proposed
5 disallowance for post painting & post inspections as well as the proposal to provide
6 a report on actual costs with amounts recovered over the past 5 years. Conversely,
7 if the Commission approves the recommended disallowances for post painting and
8 inspections, I recommend that the Company's total O&M spend should be
9 approved as reflected in Table 1 above.

10

11 PROPOSED DISALLOWANCE FOR UNDERGROUND CABLE REPLACEMENT
12 AND INCLUSION OF PROGRAM COSTS IN DISTRIBUTION GRID PLAN

13 **Q22. Witness Bunch recommends that the Commission disallow the Company's**
14 **capital investment costs for its underground cable replacement program**
15 **because DTE has not "provided reliability or cost data to justify this**
16 **program²⁰" and that these costs "have not been incorporated as part of DTE's**
17 **DGP.²¹ Do you agree with Witness Bunch's proposed disallowance?**

18 A22. No, for two reasons. First, DTE has laid out the specific criteria used to prioritize
19 and replace failed/end-of-life underground cable. The criteria referenced in DTE's
20 response to MAUI U-21534 discovery question MAUIDE-4.26 (Exhibit MAU-23
21 as part of Bunch's U-21534 direct testimony) are 1) age of cable, 2) pedestrian
22 conflict (level of pedestrian traffic), 3) recurring outages, 4) number of lights out
23 on a circuit, and 5) type of road. The Company has also provided cost data as
24 reflected on line 5 of its Exhibit A-12, B5.5, titled "Cable Replacement."

²⁰ Bunch U-21534 Direct Testimony, page 37, line 12

²¹ Bunch U-21534 Direct Testimony, page 37, lines 19-20

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1 Second, Community Lighting operates as a separate unit for which investments are
2 made unique to its assets and infrastructure (i.e. posts, fixtures, overhead &
3 underground cable, etc.), and therefore not part of the Distribution Grid Plan
4 (DGP).

5

6 **Q23. Please elaborate on the how DTE applies these criteria in selecting and**
7 **replacing cable as part of this program in relation to its projected capital**
8 **expenditures shown in Exhibit A-12, Schedule B5.5**

9 A23. This can best be demonstrated through a project the Company recently identified
10 as an underground capital cable replacement candidate. By way of background,
11 there have been several previously reported outages (as shown in the notes to the
12 right of the sketch) along the circuit located in the City of Riverview referenced in
13 Exhibit A-40, Schedule EE3. DTE has previously responded by making “locate and
14 repairs,” charged to O&M reactive maintenance, in which small sections of cable
15 are replaced to fix the specific fault (note that this type of repair does not extend
16 the useful life of the cable or mitigate future faults that may occur on the same
17 stretch of cable, as was the case here). The attached job sketch in Exhibit A-40,
18 Schedule EE3 “Riverview Capital Cable Replacement Job” shows contractor cable
19 testing results specific to a circuit in Riverview, and the notes on the job that were
20 entered into our outage management system, Kloudgin. As this sketch indicates,
21 cable testing revealed 3K – 10K Ohms of resistance (newly installed cable should
22 reflect close to zero resistance), indicating that the underground cable is end of life
23 and prone to future failures. In comparing to our criteria used for prioritization, the
24 age of the cable is at least 39 years old (using the pole install date is an indication
25 of the age of cable), there have been outages reported previously on this circuit, the

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roadway has high pedestrian traffic, and 9 lights are currently impacted. This job is representative of the types of cable replacement candidates the Company targets for long-term repairs. Mr. Bunch's proposal to deny recovery for these costs, is counterproductive, will result in the Company continuing to engage in expensive and reactive repairs, addressing only symptomatic issues, and unnecessarily increasing outage counts and customer discontent.

Table 2 below shows Company O&M costs for locate and repairs for 2022 and 2023:

Table 2 - O&M costs for locate and repairs for 2022 and 2023:

	Events	Cost
2022	2,096	\$ 898,555
2023	1,520	\$ 672,477

By contrast, the Company replaced a total of approximately 71,000 ft of cable in 2022 and another 74,000 ft of cable in 2023, under the cable replacement program. If the Company is denied recovery of its capital costs, repairs involving underground cable failures will only be able to be made through locate and repairs. As Table 2 indicates, these repairs are costly and do not mitigate the root cause.

Q24. Is Mr. Bunch correct in stating that the second reason for denial of recovery for the underground cable replacement program is that it was not included in the Company's DGP?

A24. No. As I mentioned earlier, Community Lighting's assets are separate and distinct, and operates independently from DTE Distribution Operations. The focus of the DGP is specific to distribution investments, not streetlighting. The Company defines the composition of the distribution grid and customers impacted (filed in Case No. U-20147) as including "approximately 31,000 miles of overhead

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1 distribution lines and 14,500 miles of underground distribution lines. Its service
2 territory encompasses 7,600 square miles and includes approximately 2.3 million
3 residential, commercial and industrial customers.²²”
4

5 Further, Community Lighting from a cost of service/rate design perspective,
6 maintains its own rate base, a separate set of projected capital and O&M
7 expenditures, etc.
8

9 **Q25. What is your recommendation to the Commission with respect to Witness**
10 **Bunch’s proposal to disallow recovery of underground capital cable**
11 **replacement costs?**

12 A25. I recommend that the Commission reject this proposal. The Company has
13 demonstrated that there is a direct and positive impact on lighting system reliability,
14 customer satisfaction, and a long-term cost benefit by reducing expensive locate
15 and repair work that does not mitigate the root cause, which is the failed
16 underground cable itself. The Company also has demonstrated Community
17 Lighting assets, are in fact separate and distinct from Electric Distribution, are
18 appropriately excluded from its DGP.
19

20 PROPOSED COMPANY OUTAGE PERFORMANCE AND MI-MAUI PROPOSAL
21 FOR A REPORTING SCHEME ON COMPANY OUTAGE CAUSES AND COSTS

22 **Q26. Though Witness Bunch supports recovery of the Company’s outage costs, he**
23 **caveats his support with a proposal for the Commission to “order the**
24 **Company to provide a proposed reporting scheme within three months of its**

²² Exhibit A-40, Schedule EE4 U-20147 DGP Excerpt

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1 **final order in this case, for review and discussion with Staff and**
2 **Intervenors.²³” Do you agree with this proposal?**

3 A26. No, but I do offer an alternative proposal below for the Commission to consider.
4 First however, it is important to discuss Witness Bunch’s premise as to why he
5 believes this proposal is necessary. Witness Bunch’s premise revolves around three
6 central themes. The first theme is that DTE’s outage restoration performance
7 continues to get worse. The second theme is that to the extent there have been
8 reductions, it is solely based on the sheer number of lights converted to LED. The
9 last theme being that since the Company has deployed a new outage management
10 system (OMS), it should have necessary information to provide root cause data,
11 costing data, and breakout per light.

12

13 **Q27. Please explain why you think even though Witness Bunch, while**
14 **acknowledging both outage frequency and duration are declining, states that**
15 **these declines “are not attributable to the Company’s outage response**
16 **efforts²⁴”**

17 A27. As I have discussed previously in rebuttal during Case No. U-21297, in order for
18 Witness Bunch to propose a reporting scheme, he needs there to be persistent
19 problem that cannot be solved without such a scheme. Here, I point out two
20 problems with Mr. Bunch’s assertion that performance is getting worse. First, by
21 way of his own testimony, Witness Bunch arbitrarily shifts to a pre-pandemic
22 baseline of 3.57 days without explanation or proper context. The reality is that the
23 Company as well as the rest of the world were negatively impacted by Covid
24 resulting in supply chain and resourcing constraints. Additionally, the Company

²³ Bunch U-21534 Direct Testimony, page 43, line 22 -page 44, line 1

²⁴ Bunch U-21534 Direct Testimony, page 40, line 13

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1 has been impacted by a high frequency of catastrophic storms since 2020, that
2 pulled our crews away from responding to lighting repairs. Despite these
3 challenges, the Company has consistently continued to drive down its duration from
4 a peak of 5.22 days in 2021 to 4.16 days in 2023 (U-21534 Bellini Direct
5 Testimony, Exhibit A-25, Schedule O1).

6 Second, as I have mentioned in my U-21297 rebuttal, Mr. Bunch held DTE's outage
7 performance as a baseline when critiquing Consumers in case U-20697, filed in
8 2020. In direct testimony in that case, he used DTE's outage performance to
9 contrast that of Consumers when reflecting on their 2018 outage duration.
10 Specifically, he stated "Over the last ten years, DTE has reduced average outage
11 duration from 8.5 days to 3.5 days and has reduced the incidence of outages longer
12 than 10 days almost 90%.²⁵" He went on to recognize DTE's efforts as "significant
13 improvements."

14

15 **Q28. Witness Bunch states "[a]ll reductions in outage counts can be attributed to**
16 **increased deployment of LED luminaires...²⁶" Is this true?**

17 A28. No. Witness Bunch's statement that all reductions are due to LED conversions is
18 simply not true. As referenced on page 16, lines 6-8 of my direct testimony when
19 discussing the underground cable replacement program, outages are generally the
20 result of a failed luminaire, failed wiring or components such as a photocell, or
21 failed underground cable. While replacement of HIDs with LEDs may play a part,
22 actual outage data as reflected in Exhibit A-25, Schedule O1 "Community Lighting
23 Outage Duration," in my direct testimony, coupled with Table "Community

²⁵ Witness Bunch's direct testimony, Consumers case U-20697, page 55, lines 21-22 through page 56, lines 1-2.

²⁶ Bunch U-21534 Direct Testimony, page 42, lines 5-6

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1 Lighting Assets by Type (2012-2023)” also in my direct testimony on page 8, line
2 4, provide us with data from which we can draw a fact-based conclusion. From
3 2017 – 2023, HIDs decreased by nearly 50%, being replaced generally with LEDs.
4 Reviewing outages on line 2 of Schedule O2, outage events increased from 2017
5 and peaking in 2019. This is not a coincidence, but instead 2020 happened to be
6 the first year of the Company’s proactive night patrol program, which Witness
7 Bunch now supports.²⁷ This has allowed our crews to not just replace failed
8 fixtures, but also address wiring problems and identify other root cause issues, such
9 as underground cable failures. As such, there was a steady decline in each
10 consecutive year in reported outages since the Company’s night patrol program was
11 rolled out. If Mr. Bunch’s assertion that all reductions in outage were the result of
12 LED conversions, there would have been a linear decline in both outage events and
13 reduction in HIDs in service since 2017, which was not the case.

14

15 **Q29. Witness Bunch claims the Company’s new outage management system “will**
16 **greatly increase the Company’s ability to track and report on root causes and**
17 **their costs.²⁸” Do you agree with this characterization of the Company’s new**
18 **OMS and its capabilities?**

19 A29. Somewhat. While there is merit in our ability to better track events and know where
20 we are seeing recurring outages, Witness Bunch is overstating the Company’s new
21 OMS capabilities as it relates to the system being able to provide a “taxonomy of
22 root cause outages, causes of delays in restoration, cost breakdowns, and other
23 data...”²⁹ I have clearly outlined the benefits of our new OMS system - Kloudgin,

²⁷ Bunch U-21534 Direct Testimony, page 37, lines 4-9

²⁸ Bunch U-21534 Direct Testimony, page 43, lines 5-6

²⁹ Bunch U-21534 Direct Testimony, page 44, lines 1-2

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1 and its benefits, in my direct testimony (page 21, line 21 – page 22, line 2). These
2 attributes differ from Witness Bunch’s expectations.

3

4 **Q30. Has Witness Bunch advocated that the Company be required to adopt other**
5 **outage management systems in the past noting that they possessed similar**
6 **reporting capabilities and characteristics?**

7 A30. Yes. Mr. Bunch in his direct testimony in case U-20836, proposed that the
8 Commission “[i]nstruct the Company to file plans for a networked lighting controls
9 pilot as soon as possible.³⁰” He went on to state, *without citing to any supporting*
10 *evidence* that with networked lighting controls “operating costs are reduced...” and
11 construction crews can “bring along whatever material is needed to resolve each
12 outage because the light can send diagnostic data...” and that “the costs of installing
13 and operating networked controls is largely, if not entirely, offset by reduced
14 operating costs...”³¹ When questioned through Company rebuttal as to how MI-
15 MAUI member Ann Arbor’s networked lighting control pilot had performed, Mr.
16 Bunch ceased to mention anything more on this topic, and has remained notably
17 silent since on the benefits of networked lighting control systems.
18 I mention this in relation to our OMS system, Kloudgin and the contrast between
19 the characteristics and benefits we expect to receive, with Mr. Bunch’s
20 expectations. While I can appreciate the desire to have access to this type of data
21 in the manner that Witness Bunch believes is available, the reality is, similar to his
22 promise of cost savings and efficiencies garnered by networked lighting controls,
23 that is not what is available to us today at a justifiable cost that the entire municipal
24 rate class would ultimately bear.

³⁰ Bunch U-20836 Direct Testimony, page 66, lines 14 - 15

³¹ Bunch U-20836 Direct Testimony, page 65, line 11 – page 66, line 2

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1 **Q31. You mentioned that Ann Arbor has piloted a networked lighting system**
2 **solution. Were you able to obtain any insight as to the effectiveness of this**
3 **system in terms of data collection?**

4 A31. When we asked Ann Arbor Witness Naheedy to provide data similar to the data
5 that Witness Bunch claimed was available through a networked lighting system or
6 through any other outage management system currently in use (DEAA-2.1bi
7 through DEAA-2.1ci), nothing was available.³² This is peculiar given that Ann
8 Arbor has been a MI-MAUI member for several years, yet Witness Bunch appears
9 not to have worked with its own member to employ such solutions he advocates
10 and claims DTE has readily available.

11

12 **Q32. Would you then recommend a different proposal than the one Witness Bunch**
13 **offered?**

14 A32. Yes, I would. I believe it is reasonable for a Staff facilitated workshop in which we
15 can discuss features of the Company's OMS system, what it is capable of doing and
16 not capable of doing and discuss the potential for future enhancements and whether
17 or not such investments would be prudent relative to their benefits.

18

19 LED SELECTION METHODOLOGY AND PROPOSAL FOR CONTINUED LED
20 CAPITAL DISALLOWANCE

21 **Q33. Witness Bunch on page 49, lines 17-19, continues to contend that DTE has**
22 **again "failed to meet the clear standard that the Commission set in case no. U-**
23 **21297 which is to demonstrate that its costs are consistent with reasonable**
24 **efforts to comply with roadway lighting standards." As such, he further**

³² Exhibit AA-40 Schedule EE11 DEAA-2.1bi – DEAA2.1ci

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1 recommends a cumulative disallowance of either \$7,705,567 or using
2 Consumers Energy's LED equivalencies as a benchmark then the disallowed
3 amount should be \$5,833,539.³³ Do you agree that DTE still fails to meet the
4 standard set by the Commission?

5 A33. No, I do not. I will focus my responses on four critical topics: 1) Why Leotek's
6 chart which they no longer support, is fundamental to this topic, 2) Witness Bunch's
7 misstatement of fact regarding color-correlated temperature (CCT) LEDs and
8 allegation that DTE is out of step with the industry, 3) Witness Bunch's inaccurate
9 assertion that Don McLean's analysis demonstrates DTE over light its roadways,
10 and 4) additional support for the Company's recommendation in my direct
11 testimony (page 36, lines 15-20) relating to a Staff facilitated technical workshop.

12

13 **Q34. Why is Leotek's decision to no longer support its crossover chart that was used**
14 **as the basis for Witness Bunch's proposal for disallowance and as a proxy for**
15 **DTE to use as a guide for installing lights for HID-LED conversions important**
16 **for the Commission in considering this topic?**

17 A34. It is important for two reasons. First, Witness Bunch in his U-21297 direct
18 testimony, placed sole reliance on advocating that the Company adhere to Leotek's
19 crossover chart when replacing its 100W and 250W HPS fixtures. When asked if
20 the Company should "follow the LED crossover recommendations of its primary
21 LED manufacturer," Bunch answered, "Yes, it should."³⁴ In essence, this crossover
22 chart became the new standard by which the Company was required to use in
23 replacing its 100W and 250W HPS during conversion projects.

³³ Bunch U-21534 Direct Testimony page 68, lines 13-16

³⁴ Bunch U-21297 Direct Testimony, page 24, lines 1 - 3

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1 Second, this crossover chart was used as a basis in Commission order U-21297 to
2 calculate the Company's LED disallowance as proposed by Bunch. He stated "I
3 can use witness Bellini's workpaper to find the difference in cost between the
4 Leotek recommended model, and the LEDs that DTE chose to install instead.... I
5 find that DTE overspent on unnecessarily bright LED luminaires in the amount of
6 \$5,835,192.³⁵"

7

8 **Q35. Why has the Company continued to install 58W and 136W LED luminaires**
9 **after the Commissions December 1st, 2023 order in U-21297 was received?**

10 A35. As part of the Commission's order, it cited on page 137 of the Commission's
11 December 1st order in U-21297, "Absent convincing evidence to the contrary, the
12 ALJ found that the crossover recommendations are reasonable."

13 DTE decided to reach out to Leotek as part of a fact-finding effort to understand
14 how the chart should be interpreted. In response to MAUIDE-5.48 (attached here
15 as Exhibit A-40, Schedule EE5 "MAUIDE-5.48 Leotek Removal of Crossover
16 Chart Correspondence"), I explained that we discussed how the chart was
17 developed and should be interpreted with Leotek's executive level personnel and
18 other key Leotek team members, none of whom could explain it. They decided that
19 it could not be explained and therefore removed it.

20 Without this chart, DTE decided the most prudent course of action was continuing
21 to install its 58W and 136W LEDs until further guidance can be provided by the
22 Commission. At the same time the Company engaged two industry experts as I
23 discussed in my direct testimony, to provide an assessment of the Company's LED

³⁵ Bunch U-21297 Direct Testimony, page 25, lines 15 - 20

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1 selection methodology for HID-LED conversions. Both experts independently
2 confirmed that our methodology was sound.³⁶

3

4 **Q36. Did Witness Bunch provide any evidence that he reached out to Leotek to**
5 **discuss the crossover chart?**

6 A36. No, even though Mr. Bunch had ample time in which to do so during this
7 proceeding³⁷. Instead, he glosses over this important fact by stating the Leotek
8 crossover chart is “not currently available³⁸” and finally admitting that “...Leotek
9 has removed that chart and now offers no conversion advice.³⁹”

10

11 **Q37. You mentioned that Bunch mis-represented ANSI/IES RP-8 in recommending**
12 **3,000K CCT further illustrating that DTE is out of step and inflexible in its**
13 **lighting choices?**

14 A37. Mr. Bunch asserts that “ANSI/IES RP-8 standard recommends luminaires around
15 3,000k on highways to improve driver visibility and reduce glare.⁴⁰” There is no
16 such guidance in this standard. To the contrary, the Federal Highway
17 Administration handbook⁴¹ (sponsored by the U.S. Department of Transportation)
18 states “at higher speeds, 4000K LED lighting might be beneficial for increasing
19 driver visibility (Engineering & Medicine, 2020). Similarly, other research has
20 shown that the use of 4000K light sources generally improves object detection
21 distance.⁴²” The Company’s standard stock LED is a 4000K CCT. I also discuss in

³⁶ Bellini U-21534 Direct Testimony, page 28, line 11 – page 29, line 18

³⁷ Exhibit A-40, Schedule EE9 U-21534 DEMAUI-2.1 (DEMAUI-4)

³⁸ Bunch U-21534 Direct Testimony, page 51, lines 9-10

³⁹ Bunch U-21534 Direct Testimony, page 55, line 16

⁴⁰ Bunch U-21534 Direct Testimony, page 60, lines 19-21

⁴¹ [FHWA Lighting Handbook \(dot.gov\) accessible at
https://highways.dot.gov/sites/fhwa.dot.gov/files/2023-05/FHWA-Lighting-Handbook_0.pdf](https://highways.dot.gov/sites/fhwa.dot.gov/files/2023-05/FHWA-Lighting-Handbook_0.pdf)

⁴² Exhibit A-40 EE6 2023 FHWA Lighting Handbook Excerpt

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1 my rebuttal to Ann Arbor Witness Naheedy later on, that IESRP-8-22 aligns with
2 4000K CCT as well.

3

4 **Q38. Are Witness Bunch's claims accurate when he says that Mr. McLean's**
5 **analysis demonstrates that the incumbent 100W and 250W HPS fixtures over**
6 **lit or drastically over lit roadways relative to current standards as claimed in**
7 **his direct testimony on page 57, line 20 and page line 5?**

8 A38. No, they are not. Both experts evaluated DTE's replacement LEDs as an equivalent
9 to the original HPS fixture. Most of these HPS fixtures when installed decades ago,
10 pre-dated any such set of formal standards that exist today. However, we shouldn't
11 also assume that those municipalities unwittingly selected fixtures that "over lit"
12 these roadways. A more plausible reason is that HPS lumen output, similar to LEDs
13 today, diminish/dim over its useful life. And similar to lighting standards today,
14 there are safety factors assumed built into the design. In other words, streetlight
15 systems are designed to overperform when initially deployed knowing lumen
16 output of the LED roadway luminaire will diminish over time. Witness Bunch
17 appears to acknowledge this fact when he states that Grand Rapids installs dimmers
18 on their 55W LEDs and "as the luminaire's light output slowly decreases over time,
19 Grand Rapids can adjust to yield constant illumination by giving the luminaire more
20 electricity.⁴³" Therefore, there must be what is referred to as a light loss factor
21 (LLF) included in the initial lighting design, the intent of which is to add a safety
22 factor, or measure of over-light to ensure adequate lumen output throughout the
23 fixtures useful life.

⁴³ Bunch U-21534 Direct Testimony, page 65, lines 14-15

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1 **Q39. Was there a light loss factor included in DTE's data provided to Mr. Mclean?**

2 A39. No, there was not. Had we included our light loss factor that include adjustments
3 for each roadway type, our luminance results are in line with published luminance
4 guidance.

5
6 **Q40. When incorporating LLF into the lighting analyses, does luminance fall within**
7 **industry standards?**

8 A40. Yes, they do. The Federal Highway Administration handbook states that "...it is
9 recommended that lighting not exceed the maintained lighting level specified for
10 the roadway by more than 50%...designers are encouraged to get as close as
11 possible to the required maintained level while not going below that level.⁴⁴”

12 Using the 100W analysis as an example, when adjusting for a LLF of 0.701, the
13 100W HPS and our recommended equivalent 58W LED replacement show a
14 positive result of 3% and 29%⁴⁵ respectively, both within the limits as set forth by
15 the FHWA. Notably, the 37W, 30W, and 27W LEDs all fall below the maintained
16 lighting level. Therefore, the result can be interpreted as neither the 100W HPS,
17 nor the Company's equivalent 58W LED were over lit, but instead provide adequate
18 lighting.

19

20 **Q41. Would you still recommend to the Commission that they order a technical**
21 **workshop determine an appropriate LED selection standard specific to HID-**
22 **LED conversions?**

23 A41. Yes, I would, but I would revise my recommendation given Witness Bunch's
24 apparent shift in now recommending an alternative disallowance amount that aligns

⁴⁴ Exhibit A-40 Schedule EE7 2023 FHWA Excerpt – Lighting Level Recommendation

⁴⁵ Exhibit A-40 Schedule EE8 Revised 100W HPS Analysis With LLF

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1 with Consumers equivalent LEDs used during its HID-LED conversions due to
2 Leotek no longer supporting their crossover chart.

3 Therefore, it would be reasonable to recommend that Staff conduct a technical
4 workshop or joint collaborative that includes Consumers so that we may compare
5 and contrast their LED selection methodology to DTE's. In addition to Consumers,
6 I would include as I recommended in my direct testimony: Leotek, both Dr.
7 Gibbons, Mr. McLean, MAUI, and any other interested intervenors or experts. The
8 purpose of this workshop or collaborative should be to establish an agreed upon
9 standard when selecting common LED fixtures best suited for municipal
10 streetlighting customers served by DTE. This topic is one of critical importance
11 that involves public safety and should be handled in a forum in which expert,
12 intervenor, and Company perspectives can be shared freely without risk of being
13 taken out of context. Given the voluminous and technical information provided by
14 both myself and Witness Bunch in this proceeding, a technical workshop or joint
15 collaborative is exactly the venue necessary to drive toward a resolution, and reason
16 they exist. We owe it to our communities to get this right.

17

18 **Q42. Do you also recommend that the Commission reject the cumulative**
19 **disallowance of \$7.7M (including the \$5.8M already written down by the**
20 **Company as part of Commission order U-21297)?**

21 A42. Yes. As I have discussed above, the Commission adopted MI-MAUI's proposed
22 disallowance in its order U-21297 for which the sole basis was the Leotek crossover
23 chart. The chart is no longer supported by Leotek and has been removed.
24 Therefore, I recommend the Commission reject Witness Bunch's cumulative

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1 disallowance proposal under both of his methodologies, and instead order a
2 technical workshop or joint collaborative as I have also discussed above.

3

4 LED COST OF SERVICE AND IMPACTS ON HID TO LED CONVERSIONS

5 **Q43. Witness Bunch advocates for an end to “gradualism” which the Commission**
6 **approved in its Order in Case No. U-18014, and set rates to true cost of service.**
7 **Specifically, he states on page 70, lines 16 - 18 of his direct testimony, “gradual**
8 **adjustment has not worked as intended nor within a reasonable timeline, and**
9 **its perpetuation causes a subsidy of less-efficient lights by more-efficient**
10 **LEDs.” Do you agree?**

11 A43. As previously stated on page 7, lines 14-24 of my U-20836 rebuttal testimony, and
12 again on page 8, lines 1-7 of my U-21297 rebuttal testimony, I am not advocating
13 for a specific outcome. Instead, my intent is to provide information to the
14 Commission in making a prudent decision on whether to continue using the current
15 design methodology while considering the interests of all rate payers. The reality
16 is that moving to true cost-of-service would have a significant financial impact for
17 certain communities, many of whom are under financial constraints, who still have
18 a high concentration of HID fixtures in service.

19

20 **Q44. Do you believe there continues to robust and proactive adoption by municipal**
21 **customers in converting HIDs to LEDs?**

22 A44. Yes, I do. As evidenced by the data provided in Table 2 (Community Lighting
23 Assets by Lighting Type (2012-2023))⁴⁶ from my U-21534 direct testimony (table
24 provided below for convenience), there continues to be robust and proactive
25 conversions driven by municipalities themselves:

⁴⁶ Table 2, Direct Testimony of Robert Bellini, p8, line 15

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1 Community Lighting Assets by Lighting Type (2012-2023) Further, as I mentioned

Lighting Type	2012	2017	2023
Light Emitting Diode (LED)	2,851 (1%)	53,018 (27%)	124,565 (62%)
High Pressure Sodium (HPS)	98,070 (49%)	91,422 (46%)	53,374 (27%)
Mercury Vapor (MV)	94,681 (48%)	52,518 (26%)	19,895 (10%)
Metal Halide (MH)	2,977 (2%)	2,468 (1%)	1,622 (1%)
Total Assets	198,579	199,426	199,377

2 earlier, there will be another approximately 11,000 additional municipal
3 conversions of the remaining 52,000 municipal HIDs between 2024 – 2025.

4

5 **REBUTTAL OF ANN ARBOR WITNESSES NAHEEDY & STULTS**

6 **STREETLIGHT RELIABILITY**

7 **Q45. Witness Naheedy states in his direct testimony on page 2, line 17 that**
8 **“streetlight reliability continues to be a concern for Ann Arbor...” Do you**
9 **share in Witness Naheedy’s conclusion on page 3 lines 4 – 5 of his direct**
10 **testimony that based on his impression “DTE’s outage response is very similar**
11 **to past years?”**

12 **A45. No.** As Mr. Naheedy admits, his impression of DTE’s performance was formed
13 based on testimony and data presented by his predecessor two years ago as part of
14 Case No. U-20836 stating that DTE-owned streetlights in Ann Arbor experienced
15 an average outage rate of approximately 26%.⁴⁷ The results cited from that data
16 are questionable as the Company has conducted 8 Ann Arbor night patrols from
17 2020 through 2023, with outage results ranging from 2% to 6% over that period.

18

19 **Q46. Does the City of Ann Arbor maintain outage performance metrics such as**
20 **number of outages, average duration, or outage root causes?**

⁴⁷ Witness Naheedy U-21534 Direct Testimony, page 2, lines 20-21

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1 A46. No, they do not. As I discussed and highlighted in my rebuttal to Witness Bunch's
2 proposals specific to DTE being required to collect data beyond its OMS systems
3 capabilities, Ann Arbor, who has been piloting 75 network streetlighting nodes
4 (discussed below), does not maintain or have access to any such data.⁴⁸

5
6 **Q47. Is it your understanding that Ann Arbor deployed a networked lighting**
7 **control pilot inclusive of 75 nodes?**

8 A47. Yes. Approximately 2021, Ann Arbor deployed nodes on 75 City owned
9 streetlights. My understanding was the intent was to allow for immediate
10 notification of an outage, actual outage duration from inception of event to
11 restoration, and allow for some form of root cause analysis (i.e. fixture failure,
12 wiring failure, cable failure, etc.).

13
14 **Q48. Why would it be important for the Company to glean this outage information**
15 **from the results of the City's pilot?**

16 A48. This information would help compare and contrast outage results, help understand
17 the nature of outage causes, facilitate restoration of outages, and determine how the
18 collected data sent by the nodes have assisted in optimizing restoration cost and
19 performance.

20
21 ANN ARBOR HID-LED CONVERSION PROJECT – 58W LED 3000K CCT SAMPLE
22 SELECTION

23 **Q49. Witness Naheedy states on page 5, lines 7 – 15 of his direct testimony, that it**
24 **was important for the City's sampled LEDs (both 29W and 58W) they selected**

⁴⁸ Exhibit A-40 Schedule EE11 U-21534 DEAA-2.1bi – DEAA-2.1ci

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1 **for its conversion project to “meet lighting standard IES RP-8, have a**
2 **correlated color temperature no higher than 3000K” and that “none were**
3 **“standard offerings” from DTE.” Would the City’s sampled LEDs have met**
4 **IES RP-8 standards?**

5 A49. No, they would not have. ANSI/IES RP-8-22, section 10.3.4 titled “Spectral
6 Considerations” which notes a “practical difference for 4000K, which had greater
7 detection distances especially for pedestrians, than any of the other light sources.”
8 Therefore, our standard 58W LED fixture with a 4000K CCT is the only fixture
9 that would have aligned with ANSI/IES RP-8-22, while all of Ann Arbor’s sampled
10 lights would have not been in alignment.

11

12 ANN ARBOR POSITION ASSERTING THEY WERE FINANCIALLY
13 DISADVANTAGED BECAUSE REACTIVE HPS FAILURES ARE NOW REPLACED
14 WITH EQUIVALENT COMPANY LED FIXTURES

15 **Q50. Is Witness Naheedy correct in stating that, in reference to DTE now replacing**
16 **all HPS fixtures with LEDs, had the City waited for all the HPS fixtures to fail,**
17 **that the City would have had to pay no CIAC?⁴⁹**

18 A50. No, for two reasons. First, as discussed in the previous section, our standard stock
19 LED would not have been what the City selected for installation as part of their
20 conversion project and have clearly stated that the Company’s standard stock 58W
21 LED was not acceptable, and as such they would not want this fixture installed
22 under any scenario. Second, as I mentioned in my rebuttal to Witness Bunch on
23 this topic earlier, this methodology is consistent with how conversions are handled
24 during reactive maintenance for mercury vapor lights which we began converting

⁴⁹ Witness Naheedy U-21534 Direct Testimony, page 8, lines 2-5

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1 and still do with equivalent LEDs. To the extent that a city decides to convert their
2 system to LEDs and have had MV or HPS lights replaced with equivalent LEDs
3 during reactive maintenance, those replaced lights would not be included as part of
4 the customers project costs, provided they don't want Company-installed standard
5 stock LEDs replaced.

6

7 ANN ARBOR BILL CREDIT PROPOSAL

8 **Q51. Do you agree with Witness Stults when she states in her direct testimony on**
9 **page 33, lines 2-5 that "Communities who proactively converted their**
10 **streetlights to LEDs and paid a CIAC up front should receive a credit so that**
11 **they are not paying both for the entirety of their own conversions and a portion**
12 **of others?"**

13 A51. No. In addition to the reasons I mentioned in response to Witness Naheedy's same
14 assertion above, there is no basis of fact in Witness Stults inference that Ann Arbor
15 or a similarly situated municipal customer wanting to convert to LEDs are both
16 paying for their own conversion as well as paying for a portion of others. Cost of
17 reactive conversions (including those performed in Ann Arbor) are socialized
18 among all municipalities, and municipal project conversion costs incurred to
19 convert a specific municipality's lights to LED are excluded from impacting all
20 other municipal customers (including Ann Arbor) that would otherwise be reflected
21 through higher rates. Lastly, Ann Arbor received a SEMCOG funded grant equal
22 to 80% of their total project HID-LED conversion costs.

23

24 **Q52. Does this conclude your rebuttal testimony?**

25 A52. 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-21534

REBUTTAL TESTIMONY

OF

PINA BENNETT

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF PINA BENNETT

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Pina Bennett (she/her/hers). My business address is: One Energy Plaza,
4 Detroit, Michigan 48226. I am employed by DTE Electric Company as Director,
5 Electric Marketing.

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. How is your testimony organized?**

13 A3. My testimony will address various recommended changes from multiple parties
14 with respect to the Company's electric vehicle (EV) proposals and Merchant Fees.
15 Collectively, my rebuttal testimony will address direct testimony from the
16 following parties:

17 • Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
18 Witnesses Freeman, and Revere.

19 • Attorney General (AG) Witness Coppola;

20 • Michigan Environmental Council (MEC), Natural Resource Defense
21 Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan
22 (CUB) (collectively MNSC) Witness Jester

23 • AG-MN (MEC and NRDC) Alvarez and Stephens;

24 • Michigan Energy Innovation Business Council, Institute for Energy
25 Innovation, and Advanced Energy United (MEIU) Witness Dr. Sherman;

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- 1 • City of the Ann Arbor (AA) Witness Stults;
- 2 • Electrify America LLC. Witness Shah and Davis; and
- 3 • EVgo Witness Stegall;
- 4

5 **Q4. What is the purpose of your rebuttal testimony?**

6 A4. There are 14 specific topics I will rebut in this testimony, as listed below. Unless I
7 explicitly state agreement, I will provide a detailed discussion of why the
8 intervenor's recommendations should not be accepted.

9

10 **Charging Forward**

- 11 1. Applications and Awards from Federal EV programs;
- 12 2. School Bus Charger Program update;
- 13 3. Charging Hubs update;
- 14 4. Emerging Technology Fund update;
- 15 5. Reallocation of Funds; and
- 16 6. EV Forecast
- 17

18 **Transportation Electrification Plan (TEP)**

- 19 7. Charger Uptime Requirements;
- 20 8. Destination Charging;
- 21 9. Residential Program;
- 22 10. Public Level 2 Chargers;
- 23 11. Fleet Rebates for Schools;
- 24 12. Contribution In Aid of Construction (CIAC) Waiver; and
- 25 13. Benefit Cost Analysis (BCA) for TEP.

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1 **Credit and Debit Card Merchant Fees**

2 14. Credit and Debit Card Merchant Fees

3

4 The absence of a discussion of other matters in my testimony should not be taken
5 as an indication that I agree with all other aspects of intervenor testimony. My
6 testimony instead focuses on high priority issues and responses to the positions of
7 these parties.

8

9 **Q5. Are you sponsoring any exhibits in this proceeding?**

10 A5. Yes. I am sponsoring the following exhibits:

11	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
12	A-49	NN1	Rebuttal Freeman Disallowance Residential and
13			Business Charger Rebates
14	A-49	NN2	Charging Forward Capital Expenditures
15	A-49	NN3	U-21534 EVgoDTE-1 Discovery Response
16	A-49	NN4	U-21534 AGDE-4.149c Discovery Response
17	A-49	NN5	U-21534 Discovery Responses EV Forecast

18

19 **Q6. Were these exhibits prepared by you or under your direction?**

20 A6. Yes, they were.

21

22 **Charging Forward**

23 **Q7. What is your impression of how Charging Forward is perceived by all**
24 **intervenors?**

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1 A7. There generally appears to be support for Charging Forward. Six witnesses have
2 made some suggestions, which I address below.
3

4 **Topic 1: Rebuttal to Applications and Awards from Federal EV Programs**

5 **Q8. How do you respond to Staff Witness Freeman's suggestion to supply a list of**
6 **the federal EV programs the Company has applied for and been awarded in**
7 **its next rate case (page 9, lines 19-20)?**

8 A8. The Company will provide, in the Company's next rate case, a list of the federal
9 EV programs the Company has directly applied for and been awarded.
10

11 **Topic 2: Rebuttal to School Bus Charger Program Updates**

12 **Q9. How do you respond to Staff Witness Freeman's recommendation for the**
13 **Company, in its next rate case, to discuss in detail its School Bus Charger**
14 **program and share any initial results from the program? (Page 5, lines 4-6)**

15 A9. While I believe DTE Electric has generally kept stakeholders well-informed of the
16 School Bus Charger program, the Company does file an annual EV status update
17 report and will make a point of updating the Commission on the status of the School
18 Bus Charger program, in particular, in its next EV Annual Status Report.
19

20 **Topic 3: Rebuttal to Charging Hubs**

21 **Q10. How do you respond to Staff Witness Freeman's request to provide a detailed**
22 **explanation on the progress of the Company's Charging Hub (page 5, lines 8-**
23 **19)?**

24 A10. The Company's Charging Hub pilot was designed to facilitate fleet electrification
25 by offering multiple fast chargers and pull-through spaces for heavy-duty and larger

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1 vehicles at a single location. DTE Electric was approved to spend \$2.8 million in
2 Case No. U-20836 to build, own, and operate up to two Charging Hubs and
3 encouraged by the Commission in Case No. U-21297 to pursue all available state
4 and federal funding for the project. After evaluating various sites, DTE Electric
5 backed a grant application for a hub in Southeast Michigan. In February 2023, DTE
6 Electric collaborated with the State of Michigan's Office of Future Mobility and
7 Electrification (OFME) and Daimler Truck North America (DTNA) to apply for a
8 grant for a Charging Hub in Redford, Michigan. The application was bolstered by
9 more than ten letters of support from local businesses and stakeholders. In June
10 2023, an \$8.5 million Rebuilding American Infrastructure with Sustainability and
11 Equity (RAISE) grant for the build out of the Truck ¹ Stop of the Future was granted
12 to OFME. The State's legislative spending authority process is such that the grant
13 money cannot be used or used in anticipation until the grant is signed. The grant
14 can only be signed upon final budget approval. This has led to an estimated six-
15 month delay on the project. DTE Electric has been working with the project
16 partners to execute agreements that define roles and responsibilities, the scope of
17 work, and other financial and operational details, as set forth by Witness Peterson
18 in her testimony in Case No. U-21297 (page 47, lines 5-15). The project team
19 expects to launch a Request for Proposal for the site design and engineering by the
20 end of 2024 and to begin construction on the site in 2025. Given the collaborative
21 nature of the project with the involvement of multiple state and commercial entities,
22 I agree to provide a Charging Hubs update in the Company's EV Annual Status
23 Report.

¹ [State of Michigan partners with Daimler Truck North America and DTE Energy to build Michigan's 'truck stop of the future' | Michigan Business](https://www.michiganbusiness.org/press-releases/2023/06/daimler-dte/) available at <https://www.michiganbusiness.org/press-releases/2023/06/daimler-dte/>

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1 **Topic 4: Rebuttal to Emerging Technology Fund (ETF) Progress**

2 **Q11. What is your reaction to Staff Witness Freeman's request to provide a report**
3 **on the results of the initial awards from the Company's Emerging Technology**
4 **Fund in its next rate case and yearly thereafter (page 10, line 3-4 and page 7,**
5 **lines 2-6)?**

6 A11. I believe the Company is already effectively doing so, as stated in my direct
7 testimony in this case on page 51, rows 21-22, by committing to providing Annual
8 Status Reports for its TEP programs.

9
10 **Topic 5: Rebuttal to Reallocation of Funds**

11 **Q12. How do you respond to EVgo Witness Stegall (page 15 line 20 through page 16**
12 **line 10 and page 19 lines 10-13) suggesting the Company reallocate any funds**
13 **remaining from the existing Business Charger Rebate program on December**
14 **31, 2024 into the non-DAC/rural subsegment of the proposed Business**
15 **Charger Rebate program?**

16 A12. I appreciate Witness Stegall's interest in seeing the funds reallocated. As stated in
17 my response (U-21534 Exhibit A-49 Schedule NN3 EVgoDTE-1.1c Discovery
18 Response), there are 149 sites and 593 in the pipeline to receive funding through
19 DTE Electric's Business Charger Rebate program. Given the popularity of the
20 program, as acknowledged by Witness Stegall (page 7, lines 20 through page 8, line
21 1), DTE Electric could first hold funds for any customer who has already applied
22 prior to December 31, 2024 and whose projects are showing progress to protect
23 customers who are in the process of making these large investments. If there is
24 funding remaining after this, the Company is open to reallocating the remaining

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1 funding into the non-DAC/rural subsegment of the proposed Business Charger Rebate
2 program, should there be no significant opposition from other stakeholders.

3

4 **Topic 6: Rebuttal to EV Forecast**

5 **Q13. What are the views on the forecast adoption of EVs presented by various**
6 **witnesses?**

7 A13. Two witnesses shared their opinions on the EV forecast presented by the Company
8 that was used for planning in this instant case. MEIU Witness Sherman asserts on
9 page 16, lines 4-13 that the forecasted EV deployment used by the Company in this
10 case is likely too low. Conversely, AG Witness Coppola, while not directly
11 addressing the Company's forecast, suggests on page 25 lines 1-18, and page 26,
12 lines 1-12, that the market for EVs is less than what the Company projects, and
13 therefore the Company does not need to make certain investments to accommodate
14 future growth in EVs.

15

16 **Q14. What is MEIU Witness Sherman's opinion on the EV sales forecast?**

17 A14. Witness Sherman agrees with the underlying methodology the Company used to
18 forecast EVs, however she asserts that some of the inputs may be incompatible due
19 to recently adopted Federal vehicle emissions standards from the EPA that she cites.
20 Specifically, on page 16, lines 5-13 of her testimony, Witness Sherman states that
21 "This is procedurally reasonable but on examination, two of the six forecasts
22 utilized projected national EV sales that are too low to be compatible with recently
23 adopted Federal vehicle emission standards, which the U.S. Environmental
24 Protection Agency ("EPA") characterized as based on EVs being 30 to 56 percent

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1 of light duty vehicle sales by 2032. It is therefore likely that the Company's EV
2 sales forecast is too low."

3

4 **Q15. How do you respond to Witness Shermans assertions?**

5 A15. I have several concerns. First, Witness Sherman's citation from the EPA includes
6 the following quote: "EPA projects that for manufacturing years 2030-2032
7 manufacturers may choose to produce battery electric vehicles (BEVs) for about 30
8 percent to 56 percent of new light-duty vehicles sales and about 20 percent to 32
9 percent of new medium-duty vehicle sales." The quote from the EPA is, like other
10 forecasts, an opinion on their expectations of the market. While the EPA is a
11 credible source, the Energy Information Administration (EIA), a statistical division
12 of the Department of Energy, projects 16% of new vehicle sales will be electric by
13 2032², which further highlights the reason the Company relies on multiple sources
14 to conduct its forecast. Additionally, the 2032 expectation that Witness Sherman
15 relies on to assert the sales forecast is too low is beyond the time period range of
16 the planning done for this instant case, as well as the Company's TEP which goes
17 through 2028.

18

19 **Q16. How does AG Witness Coppola characterize the market for EVs?**

20 A16. On page 25 line 4 through page 26 line 4, Witness Coppola states "During the first
21 six months of 2024, EV manufacturers have realized that electric vehicles are not
22 selling at the pace anticipated as late as 2023 and EVs are stockpiling at dealers'

² U.S. Energy Information Administration - EIA - Independent Statistics and Analysis available at <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=48-AEO2023&region=1-0&cases=ref2023&start=2021&end=2050&f=A&linechart=ref2023-d020623a.62-48-AEO2023.1-0~ref2023-d020623a.63-48-AEO2023.1-0~ref2023-d020623a.67-48-AEO2023.1-0&map=ref2023-d020623a.4-48-AEO2023.1-0&ctype=linechart&sourcekey=0>

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1 lots. EV buyers often have been dissatisfied with the actual driving range,
2 particularly during the winter and hot days that quickly drain the car batteries.
3 Reliability of certain vehicles with recalls for software and equipment failures has
4 also created customer dissatisfaction and increased concerns and fear with
5 prospective EV buyers. EV manufacturers have cut back production of EVs,
6 delayed new models, deferred building new batteries plants, and redirected
7 resources to hybrid vehicles with batteries that self charge during gasoline-fueled
8 operation. The current environment and demand for EV does not support the
9 increase in spending forecasted by the Company for 2024 and 2025 for UMR. With
10 EV adoption currently waning, I propose that the 2024 and 2025 capital
11 expenditures for UMR be set at the 2023 amount plus inflation.” He further states
12 on page 55 (lines 6-9) that “...consistent with my recommendations in the Utility
13 Make Ready testimony, I propose that the forecasted capital expenditures in
14 Schedule B5.9 [EV Charging Forward] be reduced by 45% for 2024 and 2025...”
15 Ultimately, these statements result in Witness Coppola recommending that the
16 Company be disallowed various investments on the basis that EV adoption will not
17 occur at the pace the Company expects it to.

18

19 **Q17. Do you agree with the way Witness Coppola characterizes the EV market and**
20 **that EV adoption may not materialize at the rate the Company has proposed?**

21 A17. No. I disagree with Witness Coppola’s characterization. There is ample evidence
22 to support the Company’s projections of EVs that were used as the basis for various
23 investments in this instant case. Witness Coppola characterizes the EV market in a
24 way that makes it seem like the EV market is in decline, but this is not true. EV
25 adoption is still growing, even if at a slower pace than prior projections, with

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external analysts projecting that as affordability in the mass market segment of EVs improves, adoption will follow³. In several discovery responses requested by the AG (U-21534 Exhibit A-49 Schedule NN5), the Company responded that year-to-date in 2024 EV sales experienced their highest levels on record in the state of Michigan, demonstrating continued growth, not decline, in the EV market.

Furthermore, the Company's forecast is on track as it pertains to accuracy. The Company is projecting over 22,000 new electric vehicles to enter the Service Area in 2024, which through five months of 2024, the market is on track to achieve, as seen in Table 1.

Table 1: 2024 EV Registrations

Month	Count of Registrations
January	1,240
February	1,567
March	1,772
April	2,234
May	2,603
Monthly Average	1,883
Annualized (1,883 x 12)	22,596

As it pertains to the number of EVs the Company is forecasting, the Company believes the projections presented in this instant case are conservative, and reflective of the realized pace of EV adoption. For reference, the Michigan MI

³ [J.D. Power-GlobalData Automotive Forecast July 2024 | J.D. Power \(jdpower.com\) available at https://www.jdpower.com/business/press-releases/jd-power-globaldata-automotive-forecast-july-2024](https://www.jdpower.com/business/press-releases/jd-power-globaldata-automotive-forecast-july-2024)

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1 Healthy Climate Plan⁴ targets 50% of new vehicle sales being electric by 2030.
2 Additionally, as stated above, MEIU Witness Sherman suggests EVs could make
3 up 30%-56% of new vehicle sales by 2032. Both the MI Healthy Climate Plan goal,
4 and the midpoint of the range opined on by Witness Sherman are likely higher than
5 what the Company's forecast is on pace to achieve at 22% of new vehicles being
6 electric by 2028.

7

8 **Q18. How do you respond to AG Witness Coppola's proposed capital disallowances**
9 **of \$7 million in 2024 and \$2.3 million in 2025 related to the EV Charging**
10 **Forward Program? (page 55, lines 6-9)**

11 A18. I disagree. As discussed earlier in my testimony, the Company has developed
12 reasonable projections in its EV forecast. Witness Coppola's recommendation to
13 reduce the EV Charging Forward capital spend by 45% based on a slower EV
14 adoption expectation should be rejected.

15

16 **Q19. What are your thoughts with respect to AG Witness Coppola's proposed**
17 **disallowance of 2024 and 2025 capital expenditures for utility make ready**
18 **(UMR) associated with EVs by setting such UMR expense at the 2023 amount**
19 **plus inflation due to an expectation of lower attachments based on the EV**
20 **forecast (pages 24-26)?**

21 A19. I disagree. The Commission should find that the Company's EV forecast presented
22 in this instant case is reasonable and appropriately reflects expected EV adoption
23 over time. Both the UMR expense I utilize and the Company's EV adoption
24 forecast are reasonable projections. Therefore, Witness Coppola's conclusion that

⁴ [MI Healthy Climate Plan \(michigan.gov\)](https://www.michigan.gov/healthyclimate)

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1 EV adoption is “currently waning” and recommendation to disallow \$3.7 million
2 in 2024 and \$10.2 million in 2025 of project expenditures associated with EV-
3 related UMR should be rejected.

4

5 **Q20. How do you respond to AG-MN Witness Stephen’s recommendation for an**
6 **independent expert analysis of the EV adoption forecasts (page 23, lines 17**
7 **through 20)?**

8 A20. The Company strongly disagrees with Witness Stephen’s recommendation for an
9 independent expert analysis of the EV adoption forecasts. The Company has based
10 its forecast analysis on expert external forecasts which are conducted by reputable
11 organizations with extensive experience and expertise in the field. These forecasts
12 are often based on comprehensive data and sophisticated models, making them
13 reliable sources of information. Additionally, the Company adjusts these forecasts
14 for local conditions in Michigan and its service territory. This means the forecasts
15 already take into account local factors such as the state’s economic conditions,
16 infrastructure, and policies related to EVs. Conducting an audit and independent
17 expert analysis would require significant resources, including time and money.
18 These resources could be better spent on other initiatives that directly support the
19 adoption of EVs, such as infrastructure development and customer education.

20

21 **Q21. What is your response to AG-MN Witness Alvarez’s testimony on page 20,**
22 **rows 11 through 13, indicating that about 95% of EV charging for customers**
23 **on time-of-use rates occurs off-peak?**

24 A21. The Company disagrees with Witness Alvarez’s assertion that about 95% of EV
25 charging happens off-peak. As referenced in my response to U-21534 Exhibit A-

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1 49 Schedule NN4 AGDE-4.149c Discovery Response , historical data up until
2 April 2024, shows that residential DTE Electric customers on the EV-specific rate
3 (D1.9), as well as those participating in the Home Charger Rebates pilot, had loads
4 that were below the AG's assertion at approximately 92% off-peak.

5
6 Additionally, it's important to note that not all EV owners will choose to participate
7 in the Company's programs and may opt to charge their vehicles at their
8 convenience. The report cited by Witness Alvarez rightly points out that "one
9 cannot conclude that these behavior patterns will hold as PEV technology matures,
10 charging technology and charging behaviors evolve, and PEVs achieve greater
11 market adoption beyond the early adopter phase." This suggests that as the EV
12 market matures and charging behaviors evolve, the Company may see a shift in
13 charging patterns. Therefore, it's crucial to consider this factor when planning for
14 future infrastructure and rate design.

15

16 **Transportation Electrification Plan (TEP)**

17 **Q22. What is your impression of how DTE Electric's TEP is perceived by all**
18 **intervenors?**

19 A22. There generally appears to be support for much of DTE Electric's Transportation
20 Electrification Plan by many intervenors. Eight witnesses also suggested limited
21 rejections or modifications to some of what the Company has proposed, which I
22 address below.

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1 **Q23. How do you respond to Staff Witness Freeman’s recommendation to disallow**
2 **\$8,000,000 for the Company’s Business and eFleet Charger Rebates program**
3 **(pages 8-9)?**

4 A23. I disagree with this recommendation (see Exhibit A-49 Schedule NN1 Rebuttal
5 Freeman Disallowance Residential and Business Charger Rebates). The
6 Company’s Business and eFleet Charger Rebates program for the TEP year 2025,
7 aims to support various segments, including low-income (LI) multi-unit dwellings
8 (MUDs), non-LI MUD, Public Disadvantaged Community (DAC)/Rural on-route
9 Direct Current Fast Chargers (DCFCs), other on-route DCFCs, and all fleet
10 segments. Compared to the 2024 Charging Forward levels, there’s a notable
11 increase in proposed rebate amounts per segment. For example, the average rebate
12 for low-income MUD customers is expected to be \$14,400, while DAC Public and
13 Fleet customer rebates for DCFCs are anticipated to average \$70,000. A reduction
14 in funding by \$8,000,000 would result in approximately 600 fewer rebates across
15 all proposed segments of the TEP.

16

17 **Q24. How do you respond to Staff Witness Freeman’s recommendation to disallow**
18 **\$1,000,000 for the Company’s Residential Customer Rebate program (pages**
19 **9-10)?**

20 A24. For the TEP year 2025, the Company’s Residential Customer Charger Rebates
21 program is designed to assist low-income single-family homes. This represents an
22 increase in the proposed rebate amounts compared to the 2024 Charging Forward
23 levels (see U-21534 Exhibit A-49 Schedule NN1 Rebuttal Freeman Disallowance
24 Residential and Business Charger Rebates). The average rebate is projected to be
25 \$2,200, on average, and will cover the cost of the charger and the full cost of

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1 installation; a substantial increase from the current levels of \$500 for Home Charger
2 Rebates and \$1,500 for EV Income Rebates. A funding reduction of \$1,000,000
3 would result in approximately 455 fewer rebates being available to support the
4 adoption of EVs for LI single-family home, therefore the Commission should reject
5 the recommendation.

6

7 **Q25. How do you respond to Witness Jester's reporting recommendations to**
8 **supplement the Transportation Electrification Plan with a forecast of load**
9 **profiles at line transformers, circuit feeder origination at the substation, and**
10 **at generation when electric vehicle charging is combined with existing loads at**
11 **various levels of electric vehicle adoption and by also providing an analysis of**
12 **load net of renewable generation at various levels of electric vehicle adoption**
13 **with Michigan attaining 50% renewables, 60% renewables, and 80%**
14 **renewables and to include full 8760-hour annual load profiles for electric**
15 **vehicle charging (pages 36 line 14 through page 37, page 43 lines 13-21 and**
16 **45)?**

17 A25. No, I do not agree. It poses challenges in terms of data availability, data cleaning
18 efforts, and potential misunderstanding of the data. For example, to the extent
19 public chargers are 1) not on a standalone meter and/or 2) not specifically known
20 to the Company to be a charger, the Company cannot at this time commit to the
21 granular and specific data being sought. While technology and data accessibility
22 improvements may support this requirement in the future, it would be difficult
23 today.

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1 **Topic 7: Rebuttal to Charger Uptime Requirements**

2 **Q26. How do you respond to the charger uptime statements from Electrify America**
3 **LLC. Witness Davis (page 4 through page 6 line 4)?**

4 A26. I acknowledge that charger reliability and network uptime information are
5 sensitive; the Company believes that charger uptime has to be measured to ensure
6 ratepayer funding is utilized most effectively. The 97% uptime target aligns with
7 Federal Highway Administration's (FHA) requirements, and the Company believes
8 these sites should have the same targeted reliability as National Electric Vehicle
9 Infrastructure (NEVI) EV sites, which will continue to fuel the growth of EV sales
10 in the Company's electric service territory. The Commission adopted the uptime
11 requirement in Case No. U-20836, where the Commission stated, "the Commission
12 adopts a 97% charger uptime for participants in this pilot as is currently proposed
13 by the FHA's NEVI program guidelines. Should the FHA ultimately revise or
14 update its guidance on uptime requirements upon issuance of the final NEVI rule,
15 the Commission would then be open to revisiting these guidelines and reserves the
16 right to modify this charger uptime requirement to maintain consistency with
17 federal guidelines." (Case No. U-20836 Order issued November 18, 2022, pp. 327-
18 331) I understand that many factors can impact an EV charger's uptime. Factors in
19 addition to charging equipment malfunctions such as, internet or cellular service
20 provider interruptions, outages caused by the vehicles, physical damage to the
21 charging equipment, and electric utility service interruptions can occur
22 unexpectedly, but the Charging Station Operator must be able to demonstrate that
23 the charging port would otherwise be operational. Furthermore, the Company's
24 TEP proposal does not propose to share any identifiable confidential and

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1 competitively sensitive uptime information from prospect site hosts receiving
2 rebates.

3

4 **Q27. How do you address Electrify America LLC. Witness Davis’s (page 4 line 14**
5 **through page 6 line 4) concerns regarding the Company’s participation**
6 **criteria requiring a “qualified, networked charger”?**

7 A27. The Company is open to collaborating with stakeholders on an alternate solution;
8 for example, to require a meter instead of qualified, networked chargers for
9 participating EV sites. This could potentially allow more charger providers to
10 participate and remove the burdensome process to onboard periodically qualified
11 Network Providers and requiring them to share monthly interval and session data.

12

13 **Topic 8: Rebuttal to Destination Charging**

14 **Q28. How do you respond to the recommendations from Electrify America LLC.**
15 **Witness Davis (page 6 line 15 through page 7 line 11), EVGo Witness Stegall**
16 **(page 13), and MEIU Witness Sherman (page 44) that propose to eliminate the**
17 **requirement that public DCFC must be “on-route” locations within one mile**
18 **of a major thoroughway to qualify for a rebate and instead extend these rebates**
19 **to all public DCFC locations?**

20 A28. I do not agree with Witness Davis, Witness Stegall, and Witness Sherman’s
21 proposal to eliminate “on-route” locations within one mile of a major thoroughway
22 and instead extend rebates to all public DCFC locations. DTE Electric is committed
23 to supporting 35% of the forecasted on-route public charger deployment. The
24 funding is in alignment with stakeholders' priorities. Their ranking of all public
25 charging subsegments, including on-route and destination charging, as the most

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1 important for utility action, indicates their value on public charging in reducing
2 range anxiety. The provision of fast, reliable, on-route charging within one mile of
3 a major throughway exit is crucial in increasing customer confidence in EV
4 refueling infrastructure.

5

6 **Topic 9: Rebuttal to Residential Program**

7 **Q29. What is your stance on the proposal by both MEIU Witness Sherman (page 39**
8 **lines 3-5) and AA Witness Stults (pages 29 lines 10-17) that the residential**
9 **customer rebates program set the income-qualified threshold at 400%**
10 **(Sherman) or alternatively 300% (Stults) of the federal poverty level, for the**
11 **future?**

12 A29. As I have stated in my direct testimony (page 41), the Company had, in fact,
13 envisioned an income-qualified customer eligibility threshold of 400% of the
14 federal poverty limit. During the stakeholder engagement phase of the TEP
15 development, the Company received feedback from some stakeholders that this was
16 too high. Consequently, DTE Electric lowered the income eligibility threshold to
17 200% of the federal poverty limit, which also aligns with the threshold for other
18 DTE low-income programs⁵. Witness Sherman provides an example of
19 Southwestern Public Service Company, (SPS) and its inaugural TEP and asserts
20 that DTE Electric, given the restrictive income thresholds proposed for the Single
21 Family Home rebates, may similarly struggle to deploy LI rebates. I address this in
22 my direct testimony (page 42) that it will indeed be critical to monitor and adjust
23 the income eligibility threshold based on EV adoption to meaningfully support this

⁵ [Limited Income Assistance | DTE Energy – available at
https://www.dteenergy.com/us/en/residential/save-money-energy/get-started-with/limited-income-
assistance.html](https://www.dteenergy.com/us/en/residential/save-money-energy/get-started-with/limited-income-assistance.html)

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1 segment and encourage EV adoption in Southeast Michigan. Given that the
2 program was developed with stakeholder feedback in mind, the Company does not
3 deem it appropriate to modify the threshold without further participation data.

4

5 **Q30. Do you agree with MEIU Witness Sherman's recommendation on page 39**
6 **lines 5-8 to allow customers to self-attest to their income?**

7 A30. I do not. In the Company's experience administering the EV Rebate program, many
8 customers do not necessarily pay close attention to the eligibility criteria for a
9 program, instead relying on the Company to validate their eligibility. There is risk
10 involved with customer self-attestation when individuals with higher incomes
11 could potentially falsely claim to be low-income and take away resources from
12 those who truly need them. And while self-attestation might seem that it would
13 reduce administration burden, dealing with potential fraud and its consequences
14 could actually result in more administrative work for the Company in the long run.
15 Per my testimony (page 40), over 80% of the chargers needed between 2025 and
16 2028 are expected to be in the single-family home segment and the cost of installing
17 a home charger can be a significant barrier for low-income residential customers.
18 To ensure that the correct segment of customers benefits from this program, it is
19 necessary to have checks and balances in place to administer the program
20 accurately.

21

22 **Q31. What is your stance on MEIU Witness Sherman's recommendation on page**
23 **39 line 11 through page 41 line 9 that the residential TEP program qualify**
24 **customers on a location-based criteria as an alternative option to increasing**

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1 **the threshold for rebates to 400 percent of the federal poverty level, to ensure**
2 **meaningful support for LI households through this rebate segment?**

3 A31. As stated above, the Company intends to provide meaningful support for LI
4 households through this rebate segment and will monitor and adjust the income
5 eligibility threshold based on EV adoption and considering participation data.

6

7 **Q32. How do you respond to MEIU Witness Sherman's recommendation (pages 42**
8 **line 18 through page 43 line 7) that the requirement to demonstrate tenant**
9 **interest for the MUD-based charger programs is limited to a self-attestation?**

10 A32. I agree that this may be worth considering if there are also other reasonable
11 indications of legitimate charging demand. Some examples might include those
12 identified by the Company in discovery response MEIUDE-2.4a, which is also
13 Exhibit MEIU-21 (LSS-21). This would include tenant surveys, signed letters of
14 interest from tenants, pre-commitments from tenants, documents from past requests
15 for EV charging, or data on the number of tenants with EVs.

16

17 **Q33. What is your assessment of MEIU Witness Sherman's recommendation to**
18 **modify the Company's MUD rebate proposal?**

19 A33. Witness Sherman states on page 43 lines 11-12 of her direct testimony that for
20 MUDs that do not meet the Company's LI thresholds, the site host should be able
21 to use the full \$5,000 to pay for the charger and/or any make-ready costs. That is
22 exactly what the DTE Electric TEP is intended to accomplish. The Company
23 acknowledges that while landlords of MUDs that do not meet the LI eligibility may
24 have some incentive to install chargers as an amenity to attract tenants and retain
25 occupancy, coordination issues can still exist between landlords and tenants.

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1 Hence, the Company proposed to continue its support of this segment and raised its
2 current fixed rebate for other MUDs from \$2,000 to \$5,000 per Level 2 Charger.
3 Since the rebate is a fixed amount, the full \$5,000 is intended to be awarded to the
4 successful applicant to this rebate program.
5

6 **Topic 10: Rebuttal to Public Level 2 Chargers**

7 **Q34. What is your response to MEIU Witness Sherman's recommendation to make**
8 **rebates available for public Level 2 chargers (page 45 line 13 through page 47**
9 **line 10)?**

10 A34. Site hosts considering the installation of Level 2 chargers will find the economics
11 of deployment less challenging. These chargers utilize the standard 240V electrical
12 supply, which many businesses already have in place, making electrification cost-
13 effective. Beyond the financial aspect, businesses have additional motivations for
14 installation, such as the potential for increased foot traffic, even in the absence of
15 rebates. It is important to note that the majority of future charging needs are
16 expected to be met by DC Fast Chargers (DCFCs), due to their shorter charging
17 time, and therefore, we reject the recommendation to include rebates for public
18 Level 2 chargers at this time.
19

20 **Topic 11: Rebuttal to Fleet Rebates for Schools**

21 **Q35. What is your response to MEIU Witness Sherman's recommendation to offer**
22 **partial rebates to schools that do not utilize bi-directional chargers (page 48,**
23 **lines 7-8)?**

24 A35. As stated in my testimony (page 48 lines 14-16), the Company is proposing to
25 continue its eFleet Charger Rebate program for both school and transit buses with
26 a rebate of \$70,000 per DCFC, assuming 60 kW and 150 kW DCFCs for those

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1 subsegments respectively. The Company is open to considering Witness Sherman's
2 recommendation to offer partial rebates to schools that do not utilize bi-directional
3 chargers, and implement a charger output capacity tier- based rebate approach
4 similar to the existing Charging Forward eFleets Charger Rebates.

5
6 **Topic 12: Rebuttal to Contribution In Aid of Construction (CIAC) Waiver**

7 **Q36. Do you agree with MEIU Witness Sherman's assertion on pages 11 line 6**
8 **through page 12 line 5 of her direct testimony that make-ready programs are**
9 **different from policies that waive utility CIAC requirements for EV charging**
10 **stations?**

11 A36. No. It's essential to view make-ready programs and CIAC waiver policies, their
12 goals, and impacts, as complementary tools in the toolkit for promoting EV
13 infrastructure, rather than distinct, unrelated policies. Witness Sherman's argument
14 assumes that CIAC costs and make-ready infrastructure costs are entirely separate.
15 However, in reality, these costs are interconnected. The CIAC costs are part of the
16 total cost that a customer incurs when installing new public EV charging
17 infrastructure. Therefore, any program or policy that addresses one aspect of the
18 cost inherently impacts the other. Both make-ready programs and CIAC waiver
19 policies aim to reduce the financial burden on customers installing new public EV
20 charging infrastructure. They both contribute to the broader goal of promoting the
21 use of electric vehicles, therefore, the difference in their mechanisms does not
22 change their ultimate impact. Therefore, the Commission should not consider
23 Witness Sherman's recommendation on page 50, lines 5-9, to reject the Company's
24 proposal to eliminate the CIAC policy waiver.

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- 1 **Q37. How do you respond to Electrify America LLC. Witness Shah (page 6 lines 3-**
2 **21) and MEIU Witness Sherman's (pages 11 line 17 through page 12 line 5)**
3 **reaction to the Company's removal of its CIAC waiver policy?**
- 4 A37. DTE Electric's decision to align the CIAC policy for EV customers with other
5 connections promotes fairness and equity, ensuring all customers contribute to the
6 infrastructure they use. This decision also aims to provide positive rate impacts and
7 keep rates affordable for all customers. The transition from a pilot to a permanent
8 TEP necessitates this alignment for the program's sustainability. While cost
9 certainty is important for Electrify America, it's also crucial for the Company and
10 its customers to better manage costs and reduce risk. Despite the higher capital costs
11 of developing DCFC sites, DTE Electric believes there are other ways to promote
12 public charging infrastructure, such as partnerships, grants, and incentives. The
13 implications of removing the CIAC waiver should be considered in the broader
14 context. Over the past five years that DTE Electric has been running Charging
15 Forward program, the CIAC waiver played a minimal to non-existent role⁶ (see
16 Exhibit A-49 Schedule NN2 Charging Forward Capital Expenditures) in this
17 program for the participating site hosts. Additionally, as the EV market matures
18 and the costs associated with EV infrastructure are becoming more socialized (i.e.,
19 distributed across a larger number of users), the need for such a waiver is
20 diminishing. This market maturity reduces the need for regulatory mechanisms like
21 the CIAC waiver, which were initially designed to stimulate interest and growth in
22 EV adoption.

⁶ Actual total customer-owed CIAC spend for years 2019 through 2023, was \$275,000 in relation to Exhibit A-49 Schedule NN2 Charging Forward Capital total customers as reported with response to AGDE-4.140 question.

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1 Furthermore, as EV adoption increases, the costs associated with EV infrastructure
2 are being spread across a larger user base, further reducing the per-user cost.
3 Therefore, the CIAC waiver is no longer appropriate or necessary in the context of
4 a maturing and cost-socialized EV market. Lastly, as noted with my testimony on
5 page 51, rows 9 through 12, the decision to no longer waive CIAC is in alignment
6 with feedback received from key stakeholders and making the rate book
7 modification will align the rate book and the TEP.

8

9 **Topic 13: Rebuttal to Benefit Cost Analysis for TEP**

10 **Q38. What is your reply to MEIU Witness Sherman's three concerns about the TEP**
11 **BCA (pages 20 line 8 through page 25 line 8)?**

12 A38. Witness Sherman mentions three concerns about the TEP BCA – First, she asserts
13 that the Company's BCA is overly conservative in a number of its assumptions.
14 Second, Witness Sherman concludes that the Company's BCA incorrectly assumes
15 a constant utilization rate over time for all types of chargers. Finally, Witness
16 Sherman responds that the Company's BCA fails to account for any of the societal
17 benefits realized as a result of transportation electrification.

18

19 First, accounting for all of the increase in expected revenue from increased EV
20 charging in the TEP instead of 10% of the expected revenue is a conservative
21 approach intentionally adopted by the Company. It is important to strive for
22 accuracy in estimating the benefits of EV charging and by accounting for only 10%
23 of the benefits, the BCA is approaching risk mitigation conservatively ensuring that
24 even if the actual benefits are lower than expected, the investment will still be
25 justified. Additionally, the BCA focuses on the incremental load from rebated
26 chargers, which is a more accurate reflection of the direct impact of the Company's

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1 program. While network effects and indirect impacts are important, they can be
2 difficult to measure and attribute directly to the DTE Electric program.

3
4 Second, for Witness Sherman's concern about including an increasing utilization
5 rate over time for public chargers, the Company believes it is crucial to take a
6 balanced and sustainable approach to expanding public charging infrastructure.
7 This involves taking into consideration technological advancements such as faster
8 charging times that reduce the need for a high number of public charging stations,
9 and user behavior such as EV owners' preference to charge their vehicles at home
10 overnight.

11
12 Third, the Company deems that adding additional societal benefits such as
13 greenhouse gas and criteria pollutant emission reductions to the BCA may not be
14 appropriate due to many reasons, including attribution, uncertainty, and equity. It
15 is crucial to strike a balance between comprehensive analysis and focused
16 actionable insights for the Company's operations and investments. The primary
17 purpose of the Company's BCA is to assess the costs and benefits directly
18 associated with its operations and investments, and these benefits are often indirect
19 and realized by society at large. While some additional benefits may be quantified,
20 such as using the Federal Social Cost of Carbon (SCC) to calculate the benefits of
21 carbon reductions, attributing these benefits to the actions of a single company can
22 be challenging. Additionally, future regulatory changes, technological
23 advancements, and shifts in societal behavior can significantly impact the
24 realization and magnitude of these benefits. Lastly, the additional benefits of

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1 transportation electrification (like improved air quality) might not be evenly
2 distributed and may disproportionately benefit certain groups over others.

3

4 Based on these considerations, the Commission should reject the changes Witness
5 Sherman proposes regarding modifying the Company's BCA analysis.

6

7 **Q39. How do you respond to Staff Witness Revere's (page 8 lines 1-20) concerns**
8 **regarding site-specific BCAs for fleet customers, and only allowing rebates for**
9 **net positive BCAs for other customers?**

10 A39. The Company does not agree with Staff Witness Revere. It is important to consider
11 the portfolio-level benefits that extend beyond the individual customer or fleet
12 segment. Conducting individual BCAs for each fleet customer can be
13 administratively burdensome and costly. These administrative costs, which will
14 ultimately be borne by customers, could potentially offset some of the benefits
15 derived from individual positive BCAs.

16

17 **Q40. How do you respond to MNSC Witness Jester's recommendation on page 40**
18 **line 4 through page 42 line 7 to the Commission to generally support DTE**
19 **Electric's proposed spending, without endorsing the benefit-cost analysis as**
20 **presented?**

21 A40. The Company does not agree with MNSC Witness Jester's critique of the benefit-
22 cost analysis presented by the Company and is disappointed in his unwillingness to
23 endorse it. However, the BCA as presented by DTE Electric provides an
24 appropriately comprehensive, conservative, and realistic assessment of the costs
25 and benefits of its TEP. Therefore, the Company's BCA appropriately supports the

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1 proposed levels of Company TEP spending. Witness Jester favors a BCA that far
2 exceeds the scope of this case and evaluates a wide variety of matters with, at best,
3 oblique connections to the Company's electric rates. The Company's attribution of
4 only a portion of EV adoption to DTE Electric's TEP is a conservative approach
5 that takes into account the fact that not all EV adoption can be directly attributed to
6 the Company's efforts. This approach avoids overestimating the benefits of the
7 TEP, thereby providing a more realistic assessment of its impact. Witness Jester's
8 comparison to line extensions is not entirely appropriate. Line extensions are a
9 direct result of utility investment, whereas EV adoption is influenced by a multitude
10 of factors beyond the Company's control, such as vehicle availability, government
11 incentives, and individual consumer preferences. The BCA also takes into account
12 the impacts on non-participating customers by attributing only a conservative
13 portion of EV adoption to the TEP and ensuring that the costs borne by non-
14 participating customers are not overstated. Therefore, it is reasonable for DTE
15 Electric to attribute only a portion of EV adoption to its TEP.

16

17 **Topic 14: Credit and Debit Card Merchant Fees**

18 **Q41. Did Attorney General Witness Coppola agree that DTE Electric should**
19 **continue to recover non-residential merchant fees?**

20 A41. No, Witness Coppola proposes disallowance of \$3.5 million of non-residential
21 merchant fees by the Company. Witness Coppola argues, on page 107, lines 13-16,
22 "Non-residential customers, which consists primarily of small to medium size
23 commercial and industrial businesses, have more options and sophistication than
24 residential customers to pay their gas and electric bills through other less costly
25 means, such as Electronic Funds Transfer (EFT) and Automatic Clearing House

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1 (ACH).” On page 108, lines 3-8, Witness Coppola also argues that the Company
2 should follow Consumers Energy’s actions and reimpose a convenience fee for
3 customers. DTE Electric does not agree that non-residential customers should be
4 charged a convenience fee to utilize a credit / debit card to pay their utility bill.
5 Business customers appreciate the flexibility and convenience to choose a card
6 payment transaction.

7

8 **Q42. Has DTE Electric implemented mitigation policies to decrease non-residential**
9 **merchant fees?**

10 A42. Yes. In 2019, the Company began mitigating merchant fees with a rate blocking
11 policy for large commercial and industrial customers. The Company further
12 limited usage of credit cards for customers with over \$75,000 in annual usage
13 beginning in 2021.

14

15 **Q43. Which DTE Electric non-residential customers are utilizing credit/debit cards**
16 **to pay their utility bill?**

17 A43. Given the two mitigation policies implemented, we believe the 54,000 non-
18 residential customers that utilized a card payment last year are largely small
19 business customers that often utilize credit cards to run their businesses and who
20 may not use other tools such as EFT. Furthermore, according to the National Small
21 Business Association, approximately 37% of small businesses have used credit
22 cards over the past 12 months to meet their capital needs which suggests that
23 facilitating credit card use for small business is a meaningful part of maintaining
24 business customer satisfaction and financial flexibility.

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1 **Q44. Does this conclude your rebuttal testimony?**

2 A44. 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-21534

REBUTTAL TESTIMONY

OF

SHAWN D. BURGDORF

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF SHAWN D. BURGDORF

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Shawn D. Burgdorf. My business address is 8001 Haggerty Road,
4 Suite 109, Belleville, Michigan 48111. I am employed by DTE Electric Company
5 as the Manager of the Power Supply Strategy & Modeling team within the
6 Generation Optimization department.

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company?**

10 A2. Yes.

11

12 **Purpose of Testimony**

13 **Q3. What is the purpose of your rebuttal testimony?**

14 A3. The purpose of my testimony is as follows:

15 **Section I: State Reliability Mechanism Capacity Charge**

16 1. To explain how Energy Michigan Witness Zakem's proposed exclusion of
17 Power Purchase Agreement (PPA) and Company Owned Renewable costs
18 from the "Fuel Costs" for the "energy revenue sales net of fuel cost
19 calculation" would not change the final State Reliability Mechanism (SRM)
20 capacity charge ultimately calculated on Revised Exhibit A-16. I will also
21 discuss the challenges to determine costs and reconcile seasonally as
22 proposed by Witness Zakem. Finally, I will address why using the MISO
23 Auction Clearing Price is not appropriate for use as the SRM capacity
24 charge.

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- 1 2. To address Michigan Public Service Commission (MPSC or Commission)
2 Staff (Staff) Witness Revere's alternative SRM capacity charge proposal.

3 **Section II: Energy Market Price for R10 Rate**

- 4 3. To address the use of Day-Ahead (DA) or Real-Time (RT) Locational
5 Marginal Price (LMP) to set the R10 tariff rate as proposed by Association
6 of Businesses Advocating Tariff Equity (ABATE) Witness Dauphinais.

7
8 **Q4. Are you sponsoring any exhibits in this proceeding?**

9 A4. No.

10

11 **Section I: State Reliability Mechanism Capacity Charge**

12 **Q5. Do you agree with Witness Zakem's determination (page 12, lines 11 - 23) that**
13 **removing the \$260.787 million of fuel cost associated with power purchase**
14 **agreements (PPAs) and Company Owned renewables will result in an SRM**
15 **capacity charge of \$159.21/MW-day?**

16 A5. No. The cost breakdown shown in Exhibit A-26, Schedules P1 and P2 utilize PPA
17 contract terms or Transfer Price Schedules to attribute \$260.787 million as "fuel-
18 related costs" to PPAs and Company Owned renewables. Witness Zakem only
19 removed the \$260.787 million value from fuel costs used to calculate the "energy
20 sales revenue net of fuel costs" in Exhibit A-26 and used in Revised Exhibit A-16,
21 Sched F1.5, page 1 of 6. If the \$260.787 million is not considered "fuel", then this
22 amount would be considered a capacity-related cost. The same \$260.787 million
23 amount shown on Revised Exhibit A-16, Sched F1.5, line 5, would also need to be
24 removed. Correcting for this oversight made by Witness Zakem in his Exhibit EM-
25 6, in his rebuttal, Witness Maroun provides Exhibit A-38 Schedule CC2 that

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1 removes the \$260.787 million on line 5, column (b) which shows the calculation
2 resulting in the original SRM capacity charge of \$217.30/MW-day. Thus, Witness
3 Zakem's recommended removal of the calculated PPA and Company Owned
4 renewable "fuel-related" costs from the "energy sales revenue net of fuel costs"
5 would have no impact on the \$217.30/MW-day SRM capacity charge.

6

7 **Q6. What are your thoughts on Witness Zakem's recommendation (page 14, lines**
8 **12 - 13) to "require that the SRM Capacity Charge also be determined by**
9 **season"?**

10 A6. Calculating rates for each season simply to change the allocation of costs between
11 capacity and energy will create unnecessary additional burden, and the Company
12 believes that an annual allocation is sufficient for the SRM. It will substantially
13 increase the time required to break out the costs by season as there is currently no
14 breakdown by season when projecting costs in the Company's Power Supply Cost
15 Recovery (PSCR) Plan. This creates an unnecessary burden as the annual rate
16 recovers the same costs as the rate would if computed seasonally. Additionally, all
17 load serving entities (LSEs) have to show capacity demonstrations for an annual
18 period (even if it broken down by season) and customers switching providers for
19 less than a year is unlikely. The other challenge is performing a reconciliation of
20 costs by season. This would require significant time to determine how to perform
21 such a reconciliation as it is currently performed on a calendar year basis within the
22 PSCR Reconciliation case. Even if it is determined that a seasonal reconciliation
23 could be performed, it would still require a substantial amount of time to develop
24 on a going-forward basis. As I previously mentioned, the annual rate combined

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1 with the reconciliation recovers the same costs as rates for all four seasons, thus the
2 extra effort to create seasonal rates would not be beneficial.

3

4 **Q7. Do you agree with Witness Zakem's recommendation that "A workable and**
5 **fair solution would be to set the SRM Capacity Charge at the MISO seasonal**
6 **Auction Clearing Price and apply that charge to the MW value of deficiency,"**
7 **(page 19, lines 18-19)?**

8 A7. No. Witness Zakem's proposal to tie the SRM capacity charge to the MISO
9 Auction Clearing Prices is short sighted as the MISO's Planning Resource Auctions
10 (PRAs) do not ensure long-term resource adequacy. In fact, a capacity shortage
11 situation could easily arise because MISO's PRA is for a term of only one Planning
12 Year and it is performed only two months prior to that Planning Year, whereas the
13 planning and construction of new generating capacity can take several years. When
14 LSEs properly plan for the long-term capacity needs of their customers, the PRA
15 works as a residual auction for the upcoming Planning Year by providing a means
16 to buy and sell small amounts of capacity needed due to normal variances in load
17 and generation. MCL 460.6w (PA 341) requires LSEs to demonstrate they have
18 sufficient resources to meet their resource adequacy needs on a four-year forward
19 basis and the MISO Auction Clearing Prices (ACPs) for the upcoming Planning
20 Year do not represent the cost to build new generation for a capacity deficiency.
21 "The Legislature, in its wisdom, crafted Section 6w to give the Commission a tool
22 for better ensuring the reliability of electric supply for Michigan's electric service
23 ratepayers over the long term." U-18248 Order, p. 61 (Nov 21, 2017). Witness
24 Zakem's proposal to use MISO's ACPs to set the SRM capacity charge would
25 effectively negate long-term resource planning and there would be no need for

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1 capacity demonstrations as LSEs would effectively be able to just use the 1-year
2 forward MISO PRA for all their needs. To me this outcome seems like the opposite
3 of what was intended with MCL 460.6w (PA 341).

4

5 **Q8. What are your thoughts on MPSC Staff Witness Revere’s “Alternative SRM**
6 **Calculation” discussion beginning on page 8, line 21 through page 12, line 11**
7 **of his testimony?**

8 A8. The Commission should not order Staff's proposed alternative SRM calculation due
9 to lack of detail in this case. The Company disagrees with Witness Revere's claim
10 that the proper cost of capacity is CONE, or the cost to build a combustion turbine.
11 The cost of the Company's capacity fleet is based on many diverse resources
12 required to maintain a reliable grid. Witness Revere claims his SRM calculation
13 method will avoid pitfalls yet does not show a sample calculation to prove how it
14 may fluctuate during high and low market prices. Given the lack of detail and room
15 for misinterpretation, Witness Revere's method should not be considered at this
16 time.

17

18 **Section II: Energy Market Price for R10 Tariff Rate**

19 **Q9. Do you agree with Witness Dauphinais’s recommendation that “the**
20 **Commission require DTE to modify its R10 tariff to allow all R10 customers**
21 **on an annual basis to choose between the applicable day-ahead LMP or the**
22 **applicable real-time LMP.” (page 18, lines 11-14)?**

23 A9. No. The Company does not support customers being able to choose between the
24 DA LMP and the RT LMP on any cadence. The Company submits and clears all
25 forecasted customer load (including R10 customers) into the day-ahead (DA)

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1 energy market. Any changes from that forecast are settled in the real-time (RT)
2 energy market at the RT LMP. During normal system conditions prices are very
3 similar in the DA and RT markets thus the R10 rate impact would be minimal. R10
4 load is an interruptible service and the penalties assessed by MISO are based on RT
5 LMPs which are typically much higher than DA LMPs during interruptions.
6 Allowing an R10 customer to see the DA market price (after their energy was
7 offered) and then determine how to adjust their RT load creates a mismatch to what
8 DTE submits in the DA market. The increase in RT costs due to deviations from
9 the DA offers would be paid for by other DTE customers. Another way to address
10 the issue of RT penalties from MISO would be to directly pass through the MISO
11 penalties associated with not interrupting and remove the \$50/kW penalty that is
12 currently in the R10 tariff. This would hold other customers harmless regardless of
13 the LMP rate in the R10 tariff. In addition to the “gaming” concern raised by
14 Witness Dauphinais, if customers switch regularly and are allowed to choose
15 between the two different LMPs this would create additional burdens and cost to
16 DTE Electric for tracking and billing.

17

18 **Q10. Does this conclude your rebuttal testimony?**

19 A10. Yes it does.

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.)

JEFFREY C. DAVIS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JEFFREY C. DAVIS

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Jeffrey C. Davis (he/him/his). My business address is: 6400 North
4 Dixie Highway, Newport, Michigan, 48166. I am employed by DTE Electric
5 Company at the Fermi 2 Nuclear Power Plant as Expert - Nuclear Strategic
6 Business Operations.

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company (DTE Electric or Company)?**

10 A2. Yes.

11

12 **Purpose of Testimony**

13 **Q3. What is the purpose of your rebuttal testimony?**

14 A3. The purpose of my rebuttal testimony is to rebut the positions of Witness Kindschy
15 who provided direct testimony on behalf of the Michigan Public Service
16 Commission (MPSC) Staff (Staff) and of Witness Coppola who provided direct
17 testimony on behalf of the Michigan Attorney General (AG). Specifically, my
18 rebuttal will address both Witness Kindschy's and Witness Coppola's proposed
19 disallowances of Nuclear Generation capital expenditures.

20

21 **Q4. Are you sponsoring any exhibits in this proceeding?**

22 A4. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-47	LLI	Nuclear Production Plant
A-47	LL2	Nuclear Fuel Expenditures

Line
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1 **Q5. Were these exhibits prepared by you or under your direction?**

2 A5. Yes, they were.

3

4 **NUCLEAR GENERATION CAPITAL EXPENDITURES**

5 **Q6. Why are you rebutting the direct testimonies of Witness Kindschy and Witness**
6 **Coppola relative to the Nuclear Generation capital expenditures?**

7 A6. Taken together, the proposed Nuclear Generation capital expenditures
8 disallowances proposed by Witness Kindschy and Witness Coppola represent an
9 imprudent and unreasonable reduction of approximately \$181.4 million in Nuclear
10 Generation's projected project capital expenditures. Nuclear Generation's
11 projected project capital expenditures for the 24-month-period-ending December
12 31, 2025, in total, were approximately \$263.6 million so these proposals would
13 eliminate nearly 70% of the Company's projected capital expenditures for two
14 years at the Fermi 2 Power Plant (Fermi 2). The Company's proposed expenditures
15 are consistent, both operationally and economically, with historical capital
16 deployment at Fermi 2.

17

18 Additionally, Witness Coppola proposed a reduction of approximately \$20.0
19 million of nuclear fuel expenditures against DTE Electric's projected nuclear fuel
20 expenditures for the 24-month-period-ending December 31, 2025, of
21 approximately \$137.1 million.

22 Both Witness Kindschy's and Witness Coppola's proposed disallowances were
23 reached by applying a series of inappropriate conclusions which I will individually
24 rebut later in my testimony.

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1 **Q7. Are there overlapping proposed capital reductions between Staff Witness**
2 **Kindschy's proposed reduction of approximately \$45.6 million and AG**
3 **Witness Coppola's proposed reduction of approximately \$175.4 million of**
4 **Nuclear Generation capital expenditures?**

5 A7. Yes, there is overlap in proposed Nuclear Generation capital expenditures
6 reductions between Witness Kindschy's proposals and Witness Coppola's
7 proposals. To simplify my rebuttal testimony, I plan to address each proposed
8 reduction on its own independent merits.

9

10 **MPSC STAFF PROPOSALS**

11 **Q8. What are your thoughts concerning Witness Kindschy's proposed reductions**
12 **of approximately \$45.6 million of Nuclear Generation from rate base?**

13 A8. The proposed removal of approximately \$45.6 million of Nuclear Generation
14 capital expenditures would not be reasonable and would not be prudent.

15

16 Nuclear Generation projects support the safe and reliable operation of the Fermi 2
17 Power Plant. I supported the reasonableness of the Nuclear Generation Projects
18 with the total historical period actual expenditures of approximately \$254.5 million,
19 and the projected capital expenditures of approximately \$339.5 million and \$80.1
20 million for the 24-month bridge period ending December 31, 2024, and the 12-
21 month projected test period ending December 31, 2025 respectively as depicted on
22 line 4, page 1 of Exhibit A-12, Schedule B5.3, in my direct testimony, augmented
23 by the Part III documents and other supporting documentation such as design
24 documents, commercial agreements and internal capital appropriations
25 authorizations provided in the due course of this proceeding.

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1 The Commission should not adopt Witness Kindschy's proposals so that DTE
2 Electric can continue with its work plans to operate the Fermi 2 Power Plant safely
3 and reliably as discussed in my direct testimony.

4

5 **Q9. How did Witness Kindschy arrive at the proposed capital expenditure**
6 **reduction of approximately \$45.6 million of Nuclear Generation capital**
7 **expenditures?**

8 A9. Witness Kindschy proposed capital expenditure reductions of approximately
9 (summarized by Witness Kindschy in Exhibit S-16.3):

- 10 • \$15.7 for Nuclear Generation capital expenditures for the 5-month period
11 ending April 30, 2024 (divided \$7.9 million for Routine and Small Projects
12 and \$7.9 million for Non-Routine and Large Projects)
- 13 • \$13.6 million for Nuclear Generation capital expenditures for the 7-month
14 period ending December 31, 2024 (divided as \$3.7 million for Routine and
15 Small Projects and \$9.9 million for Non-Routine and Large Projects)
- 16 • \$16.2 million for Nuclear Generation capital expenditures for the 12-month
17 period ending December 31, 2025 (divided \$8.5 million for Routine and
18 Small Projects and \$7.7 million for Non-Routine and Large Projects)

19

20 **Q10. What are your thoughts concerning Witness Kindschy's conclusion?**

21 A10. Witness Kindschy's conclusions are built upon three misconceptions: (1) Nuclear
22 Generation's project expenditure variances-to-plan (actuals compared to
23 projections provided in this electric rate case) for the 5-month period ending April
24 30, 2024 were not due to timing but rather due to performance, (2) then using those
25 misunderstood project expenditure variances-to-plan as her support to infer Nuclear

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1 Generation systematically projects its capital project expenditures on the high-side
2 of any expenditure uncertainty, and (3) then proposing as a remedy to remove this
3 perceived systematic high-side projection by the use of a certain project
4 management estimating model that is not applicable to Nuclear Generation
5 projected capital expenditures as depicted in Exhibit A-12, Schedule B5.3.

6

7 **Q11. What do you mean by timing and performance variance?**

8 A11. Timing variance means work has completed or will be completed at the projected
9 expenditure, but the timing of this projected expenditure is sooner or later than
10 expected. In contrast, performance variance means the work has completed or will
11 complete at an actual expenditure higher or lower than expected.

12

13 As Witness Kindschy is proposing broad reductions to the entire Nuclear
14 Generation portfolio of projects, I will take a moment to discuss individual project
15 timing impacts in the context of portfolio management. While prudent management
16 of a portfolio of projects certainly requires an understanding of the basis for the
17 timing variance; it would be unreasonable and not prudent to change or manage the
18 priorities of the portfolio based on timing variances as these timing variances can
19 reasonably be expected to converge to plan. Conflating timing variances and
20 performance variances within the greater portfolio management regime can lead to
21 non-optimal execution of priorities – it is after a project has completed or will
22 complete higher or lower in cost than projected that priorities are reevaluated to
23 achieve targeted expenditures (reference my direct testimony at line 12 of JCD-47).
24 None of Witness Kindschy's proposed reductions address a circumstance at Fermi
25 2 involving a performance variance.

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1 **Q12. Why else do you mention reasonable and prudent “portfolio of projects”**
2 **rather than just reasonable and prudent management of individual projects?**

3 A12. As a noteworthy example, Nuclear Generation capital projects that are being
4 implemented during a refueling outage – because of the highly-integrated nature of
5 refueling outages – must be managed as an integrated portfolio of capital projects.
6 The execution of the refueling outage itself and the management of the overall
7 portfolio target expenditures provides for optimized decision-making versus
8 managing variances (timing or performance) on a project-by-project level.

9

10 **Q13. How does the “highly-integrated nature of refueling outages” impact**
11 **individual projects?**

12 A13. As I stated in my direct testimony, DTE Electric manages incremental supplier
13 personnel as a total. Individual projects must share these resources (such as
14 scaffolders, insulators, radiation protection, etc.) and as an outage schedule updates,
15 these resources are likely to be used by the projects in variance to the individual
16 projections, yet the total resource usage remains controlled per total refueling
17 outage capital projections. So, although individual capital projects may have
18 variance, the whole of the capital projects implemented during the refueling outage
19 will be on plan.

20

21 **Q14. Why would controlling resources in total be reasonable and prudent during a**
22 **refueling outage?**

23 A14. This is the most reasonable and prudent approach to managing and controlling the
24 timing of the work performed during a refueling outage. In the alternative – if DTE
25 Electric managed resources to each individual project cost projection, then that

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1 would require each individual project to have dedicated resources that could not be
2 shared – which would decrease resource efficiency, increase the total costs of each
3 project and increase Nuclear Generation’s capital expenditures in general – which
4 would not be reasonable and not prudent.

5

6 **Q15. What are your thoughts concerning Witness Kindschy’s proposed reductions**
7 **based on Nuclear Generation’s actual capital expenditures for the 5-month**
8 **period ending April 30, 2024?**

9 A15. Witness Kindschy inappropriately treats timing variances for the 5-month period
10 ending April 30, 2024, as permanent under-spends (performance variances). The
11 Fermi 2 Refueling Outage 22 (RF22) was in progress during April 2024 which
12 Witness Kindschy did not factor in her variance analysis. As I explained in my
13 direct testimony: (1) at line 12 of JCD-47, “Nuclear Generation manages capital
14 expenditures for the period and expected capital expenditures in total will be
15 incurred as projected” as in the period through the projected test year and (2) at line
16 21 of JCD-8, “Work such as capital replacements and modifications are
17 implemented when the plant is in the safest condition to do so. For most of our work
18 at Nuclear Generation, that safest condition is when the Fermi 2 plant is shut down
19 for a refueling outage.”

20

21 Nuclear Generation capital expenditures peak during the refueling outages. Capital
22 expenditures in the months leading up to and through a refueling outage constitute
23 most Nuclear Generation capital expenditures for the 24-month cycle. In fact,
24 capital expenditures within the refueling outage are not homogenous with respect
25 to schedule and can vary each outage. Generally speaking, capital expenditures

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1 during a refueling outage peak early in the refuel outage as that's when the material
2 is being withdrawn from the warehouse and when the maximum number of
3 incremental supplier personnel is on site, as the outage progresses incremental
4 supplier personnel demobilize as the scope completes and daily capital costs trend
5 lower, then capital costs peak again at the end of the refueling outage schedule as
6 plant components such as the reactor vessel, the drywell and the turbine systems
7 are returned to operations and associated capital costs are recognized. It is simply
8 not possible to draw an accurate conclusion as to total capital expenditures at a
9 nuclear plant by using monthly capital expenditures using only a portion of a
10 refueling outage actual costs – which is what Witness Kindschy did with her 5-
11 month period ending April 30, 2024 project variance analysis.

12

13 **Q16. When is a reasonable time following a refueling outage to review the capital**
14 **expenditures and make final assessments of the variances?**

15 A16. Three months following a refueling outage is generally sufficient time to allow all
16 final invoices to be receipted and to minimize timing variances. In the case of RF22,
17 which completed in May 2024, the three months would be complete with the
18 business close of July 2024.

19

20 **Q17. What were Nuclear Generation capital expenditures for the 8-month period**
21 **ending July 31, 2024?**

22 A17. Exhibit A-47, Schedule LL1 Nuclear Generation Capital Expenditures updates
23 DTE Electric's actual Nuclear Generation capital expenditures that Witness
24 Kindschy included in her Exhibit S-16.6 to include May, June, and July 2024
25 expenditures. The \$160.4 million depicted at line 4, column (j), page 1 of Exhibit

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1 A-47, Schedule LL1 is the total Nuclear Generation project capital expenditures for
2 the 8-month period ending July 31, 2024. The \$162.8 million depicted at line 5,
3 column (j), page 1 of Exhibit A-47, Schedule LL1 is the total Nuclear Generation
4 project capital expenditures for the 8-month period ending July 31, 2024, as
5 projected in the Exhibit A-12, Schedule B5.3. DTE Electric's Nuclear Generation
6 total capital expenditures for this 8-month period was essentially on plan.

7

8 **Q18. How should the Commission evaluate the Nuclear Generation actual**
9 **expenditures through July 2024 and the projected test period?**

10 A18. DTE Electric has reasonably and prudently completed its implementation of the
11 RF22 scope as projected in my direct testimony. I have demonstrated that Nuclear
12 Generation's capital expenditures through RF22 were at projected amounts after
13 accounting for timing associated with RF22; therefore, the Commission should not
14 adopt Witness Kindschy's proposed reduction of approximately \$15.7 million for
15 Nuclear Generation for the 5-month period ending April 30, 2024. Also, since
16 Witness Kindschy relied at least in part on timing variances of Nuclear
17 Generation's capital expenditures to justify further reductions in projected capital
18 expenditures, I would recommend the Commission not adopt Witness Kindschy's
19 proposed reductions for the 7-month period ending December 31, 2024, and the 12-
20 month period ending December 31, 2025, as well.

21

22 **Q19. Setting aside the timing variance for a moment, is Witness Kindschy correct**
23 **in concluding that Nuclear Generation includes high-side over-projections in**
24 **its expenditures depicted in Exhibit A-12, Schedule B5.3?**

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1 A19. No. As I stated in my direct testimony, Nuclear Generation removes all
2 contingencies from rate case exhibits; further, I state in direct testimony at line 25
3 of JCD-46 “some known scope with highly uncertain costs have projected
4 expenditures excluded from exhibits. DTE Electric takes reasonable and prudent
5 measures to depict capital expenditures as they are projected to be incurred.”

6

7 **Q20. Are you generally aware of the Association of Advancement of Cost**
8 **Engineering (AACE) estimating techniques used by Witness Kindschy as a**
9 **basis for proposed Nuclear Generation capital reductions of approximately**
10 **\$29.8 million?**

11 A20. Yes, to the extent of the information provided in Witness Kindschy’s direct
12 testimony and exhibits. The Association of Advancement of Cost Engineering
13 International (AACE) is one of several organizations that provide professional
14 development and certification for professional cost engineers. Witness Kindschy
15 referenced an AACE document titled AACE International Recommended Practice
16 No. 18R-97 titled, “COST ESTIMATE CLASSIFICATION SYSTEM – AS
17 APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR
18 THE PROCESS INDUSTRIES” (AACE Process Industries Recommended
19 Practices) as Exhibit S-16.3.

20

21 On page 2 of the AACE Process Industries Recommended Practices (page 3 of
22 Kindschy Exhibit S-16.3) is a table labeled “COST ESTIMATE
23 CLASSIFICATION MATRIX FOR THE PROCESS INDUSTRIES” that provides
24 a summary of AACE’s estimate “classes” and their associated primary
25 characteristic and secondary characteristics. Witness Kindschy’s primary focus is

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1 towards each AACE estimate class and its associated secondary characteristic of
2 “expected accuracy range.”

3

4 To formulate a proposed disallowance for Nuclear Generation’s projected
5 expenditures for the 8-month period ending December 31, 2024, Witness Kindschy
6 applied a 15% value found in the AACE estimate class 4 secondary characteristic
7 Expected Accuracy Range.

8

9 To formulate a proposed disallowance for Nuclear Generation’s projected
10 expenditures for the 12-month period ending December 31, 2025, Witness
11 Kindschy applied a 20% value found in the AACE estimate class 5 secondary
12 characteristic Expected Accuracy Range.

13

14 **Q21. Are there aspects of the AACE Process Industries Recommended Practices**
15 **that are inconsistent with my explanation of Nuclear Generation’s and the**
16 **Commission’s practice concerning contingencies?**

17 A21. Yes. Note [a] of the COST ESTIMATE CLASSIFICATION MATRIX FOR THE
18 PROCESS INDUSTRIES (page 3 of Kindschy Exhibit S-16.3) clarifies, “The state
19 of process technology and availability of applicable reference cost data affect the
20 range markedly. The +/- value represents typical percentage variation of actual
21 costs from the cost estimate after application of contingency (typically at a 50%
22 level of confidence) for given scope.” (Emphasis added). As I confirm in my direct
23 testimony, Nuclear Generation capital expenditures exclude contingencies.

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1 **Q22. Does the AACE Process Industries Recommended Practices provided in**
2 **Witness Kindschy's Exhibit S-16.3 indicate an intention that it is appropriate**
3 **for to application to projects for operating nuclear power plants?**

4 A22. No. Page 1 of the AACE Process Industries Recommended Practices (page 2 of
5 Witness Kindschy's Exhibit S-16.3) states "This addendum to the generic
6 recommended practice provides guidelines for applying the principles of estimate
7 classification specifically to project estimates for *engineering, procurement, and*
8 *construction (EPC)* work for the *process industries*" emphasis added where process
9 industry generally refers to industries such as oil refinery or production of
10 chemicals and EPC generally refers to larger turnkey construction projects (note:
11 none of the Nuclear Generation capital expenditures depicted in Exhibit A-12,
12 Schedule B5.3 would be considered EPC/turnkey).

13

14 **Q23. Did Witness Kindschy otherwise discuss how she chose to use the AACE**
15 **estimating techniques for her proposed disallowances?**

16 A23. No. It is unclear how AACE estimating techniques became Witness Kindschy's
17 preferred method for identifying projected cost uncertainties. In reference to justify
18 applying the AACE estimate classes 4 and 5 to projected Nuclear Generation
19 capital expenditures, Witness Kindschy note son page 11 of her direct testimony at
20 line 3 "Staff's recommended reductions to 2024 and 2025 are further supported by
21 the comparison of the actual capital expenditures through April 2024 to what the
22 Company included in its case."

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1 **Q24. Does the timing variances identified by Witness Kindschy confirm the**
2 **appropriateness of Nuclear Generation's use of the AACE estimating**
3 **techniques?**

4 A24. No. As I discussed earlier, the Nuclear Generation's timing variances have been
5 minimized following the conclusion of RF22 and capital expenditures for the 8-
6 month period ending July 31, 2024, were approximately to plan. Any variance for
7 the 5-month period ending April 30, 2024, was coincidental and not indicative of
8 Nuclear Generation using capital expenditure projections with uncertainties
9 bounded by AACE Process Industries Recommended Practices.

10

11 **Q25. Are the Company's Nuclear Generation capital project expenditures created**
12 **by AACE-certified cost engineers or by applying the standards recommended**
13 **by AACE?**

14 A25. No.

15

16 **Q26. If Nuclear Generation capital expenditure projections are not provided by**
17 **AACE-certified cost engineers, is the Company confident the expenditures will**
18 **be incurred as projected?**

19 A26. Nuclear capital expenditure projections are, in general, relatively straight forward
20 application of quantities multiplied by rates distributed in time based on scheduled
21 resource use. Many Nuclear Generation projects are routine capital replacements,
22 DTE Electric has executed this work since operations began and will continue to
23 execute this work for as long as operations continue to support safe and reliable
24 operations. As I discussed in my direct testimony, contracts for work and materials
25 are well established (so unit rate is well-defined) and materials and labor schedules

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1 are planned months in advance (so resource use is well-defined). Nuclear
2 Generation's expectation, as it is across the nuclear industry, is to adhere to the
3 schedule; therefore, DTE Electric is confident in its capital expenditure projections.
4

5 **Q27. How would you characterize the Nuclear Generation capital expenditures**
6 **depicted in Exhibit A-12, Schedule B5.3 for each project?**

7 A27. I think it would be appropriate and fair to characterize the Nuclear Generation
8 capital expenditures depicted in Exhibit A-12, Schedule B5.3 as already
9 representing the lower bound of a reasonable expenditure projection for each
10 project. Further reduction by applying a non-applicable standard would result in an
11 unreasonable and imprudent reduction in Nuclear Generation's capital
12 expenditures.
13

14 **Q28. Are there other considerations with respect to Witness Kindschy's proposed**
15 **reductions?**

16 A28. Yes. Witness Kindschy's generalized proposed reductions apply to all Nuclear
17 Generation projects, including those projects that will not be in service until beyond
18 the projected test period. As DTE Electric Witness Uzenski explains in her rebuttal
19 testimony on page TMU-8-Reubttal, "such disallowances should have no impact"
20 to DTE Electric's requested rate relief.
21

22 **ATTORNEY GENERAL PROPOSALS**

23 **Q29. What are your thoughts concerning Witness Coppola's proposed reductions**
24 **of approximately \$175.4 million of Nuclear Generation capital from rate base?**

Line
No.

1 A29. The proposed removal of approximately \$175.4 million of Nuclear Generation
2 capital expenditures would not be reasonable and would not be prudent.

3
4 Nuclear Generation projects support the safe and reliable operation of the Fermi 2
5 Power Plant. I supported the reasonableness of the Nuclear Generation Projects
6 with the total historical period actual expenditures of approximately \$254.5 million,
7 and the projected capital expenditures of approximately \$339.5 million and \$80.1
8 million for the 24-month bridge period ending December 31, 2024, and the 12-
9 month projected test period ending December 31, 2025 respectively as depicted on
10 line 4, page 1 of Exhibit A-12, Schedule B5.3, in my direct testimony, augmented
11 by the Part III documents and other supporting documentation such as design
12 documents, commercial agreements and internal capital appropriations
13 authorizations provided in the due course of this proceeding.

14
15 The Commission should not adopt Witness Coppola's proposals so that DTE
16 Electric can continue with its work plans to operate the Fermi 2 Power Plant safely
17 and reliably as discussed in my direct testimony.

18

19 **Q30. How did Witness Coppola arrive at the proposed reduction of approximately**
20 **\$175.4 million of Nuclear Generation capital expenditures?**

21 A30. Witness Coppola proposed reductions of approximately:

- 22 • \$83.9 million for Nuclear Generation projects that will be placed into
23 service beyond the projected test period (Witness Coppola's direct
24 testimony at line 2-3, page 46)

Line
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- 1 • \$41.1 million for the Plant Radio System (Witness Coppola's direct
- 2 testimony at line 12-13, page 42) and Security Computer System projects
- 3 (Witness Coppola's direct testimony at line 8-9, page 40)
- 4 • \$24.0 million for Natural Draft Cooling Towers, Document Management
- 5 System Enhancements, and Remote Monitoring projects (Witness
- 6 Coppola's direct testimony at line 16, page 45)
- 7 • \$20.0 million for nuclear fuel (Witness Coppola's direct testimony at line
- 8 4, page 44), and
- 9 • \$6.5 million for Sanitary Sewer System work (Witness Coppola's direct
- 10 testimony at line 9, page 46)

11

12 **Q31. What are your thoughts concerning Witness Coppola's proposal to reduce**
13 **approximately \$83.9 million of rate base for Nuclear Generation projects that**
14 **DTE Electric plans to place into service after the projected test period?**

15 A31. My direct testimony supports the reasonableness and prudence of these project
16 expenditures. Witness Coppola appears to be making only an accounting argument
17 as the basis for excluding these projects, so I refer to DTE Electric Witness
18 Uzenski's discussion on page TMU-8-Rebuttal that confirms that "projects that do
19 not go into service during the projected test period have no impact on the
20 Company's revenue requirement and deficiency." DTE Electric added the in-
21 service year projection to Exhibit A-12, Schedule B5.3, pages 2 - 4 to be transparent
22 about project in-service dates and impact to revenue requirement.

23

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1 **Q32. What are your thoughts concerning Witness Coppola's proposal to reduce**
2 **approximately \$41.1 million of capital expenditures for the Security System**
3 **Computer and Plant Radio Projects?**

4 A32. Witness Coppola apparently misunderstood the internal capital appropriations
5 request forms that the Company provided and misinterprets an initial partial
6 appropriation for a baseline budget. This misunderstanding causes Witness
7 Coppola to incorrectly assert that the Security System Computer and Plant Radio
8 projects have incurred or are projected to incur unreasonable or imprudent
9 expenditures.

10

11 **Q33. What was the baseline budget for the Security Computer System?**

12 A33. As depicted on page 2 of Witness Coppola's confidential Exhibit AG-9, the initial
13 baseline budget for the Security System Computer project was approximately \$25.2
14 million. This appropriation was internally approved on January 26, 2023.

15

16 **Q34. Can you explain the \$9,948,000 amount for the Security System Computer**
17 **referenced by Witness Coppola?**

18 A34. The approximately \$9.9 million referenced by Witness Coppola was an initial
19 partial appropriation approval to initiate the project. The initial appropriation was
20 only sufficient to start the project and develop the information required to develop
21 the baseline budget and present the project for full project authorization. This is a
22 reasonable practice when the necessity and reasonableness of the intended work is
23 not in doubt, as is often the case in Nuclear Generation.

24

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1 **Q35. Is an initial partial appropriation prior to requesting a full baseline budget**
2 **standard practice?**

3 A35. Yes. It is standard practice to authorize larger project capital expenditures in
4 tranches so that the initial baseline budget once authorized can be used to measure
5 changes in scope, schedule, and budget.

6
7 **Q36. What were the initial partial appropriation and the baseline budget for the**
8 **Plant Radio project?**

9 A36. As depicted on page 2 of Witness Coppola's confidential Exhibit AG-10, the initial
10 baseline budget for the Plant Radio System project was approximately \$15.8
11 million. The initial partial appropriation for Plant Radio System was \$6.0 million.
12 This appropriation (baseline budget) was internally approved October 28, 2022.

13
14 **Q37. Why does the initial baseline budget authorization for the Plant Radio System**
15 **include only a narrative that stated, "Requesting total appropriations costs**
16 **associated with Plant Radios Mod for alignment with 8+4 2022 forecast?"**

17 A37. Appropriation forms are internal DTE documents, the scope of the Plant Radio
18 System project was generally understood so additional narrative was not provided.
19 As this appropriation form was to authorize the baseline line budget, the narrative
20 included states that the change is for "appropriations total costs" vs partial
21 appropriations.

22
23 **Q38. What were the total expenditures depicted in rate cases for the Plant Radio**
24 **System and Security System Computer projects?**

Line
No.

1 A38. Both projects were initially presented to the Commission in DTE Electric rate Case
2 No. U-20836. The total amount depicted in U-20836, Exhibit A-12, Schedule B5.3
3 for the Security System Computer project was \$24.8 million. The total amount
4 depicted in Case No. U-20836, Exhibit A-12, Schedule B5.3 for Plant Radio
5 System project was \$8.1 million. DTE Electric again depicted these projects in DTE
6 Electric rate Case No. U-21297 Exhibit A-12, Schedule B5.3 at \$23.9 million and
7 \$11.9 million for the Security System Computer and Plant Radio System projects,
8 respectively.

9

10 **Q39. Does the recently authorized Security System Computer project**
11 **appropriations (page 4 of Witness Coppola's confidential Exhibit AG-9)**
12 **request accurately describe why the project changed its baseline budget from**
13 **approximately \$25 million to \$39 million?**

14 A39. Yes. The recently authorized Security System Computer project appropriation to
15 increase the project's baseline costs to approximately \$39.2 million includes a
16 description of nine items that changed relative to the original baseline budget. Most
17 notable is the design and implementation of the Secured Owner Controlled Area
18 (SOCA) building as these expenditures were uncertain in prior rate cases and
19 excluded from previous projections. Other updates to scope and schedule such as
20 to use a more reliable technology for intrusion detection and to use recent operating
21 experience to add a fully integrated system site acceptance test prior to in-servicing
22 the project are reasonable and prudent updates to the project. As I state in my direct
23 testimony starting at line 25 of JCD-46, "some known scope with highly uncertain
24 costs have projected expenditures excluded from exhibits (such as the Security

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1 Computer Replacement project) until such time the expenditures are capable of
2 being identified with reasonable specificity to include in the exhibit[.]”
3

4 **Q40. Does the updated Plant Radio project appropriations (page 4 of Witness**
5 **Coppola’s confidential Exhibit AG-10) request accurately describe why the**
6 **project baseline budget changed from approximately \$16 million to \$19**
7 **million?**

8 A40. Yes. Though, in the case of this updated Plant Radio project appropriation, the
9 variance narrative could have provided additional context such that it was clear that
10 “legacy issues with undersized wiring feeding the transformers of the UPS” means
11 that when DTE Electric approved the initial baseline scope, the wires powering the
12 uninterruptible power supplies (UPS) were assumed to have sufficient capacity to
13 operate safely with the UPS units required for the Plant Radios; however field
14 inspections and engineering calculations demonstrated that the wires would be
15 insufficient to support the new Plant Radio System. As I have discussed, since
16 Nuclear Generation and, in general DTE Electric, does not include contingencies
17 in its rate case projections, establishing expenditure projections to replace wiring
18 in the contingent event that the wire may not have sufficient capacity would be
19 inappropriate.
20

21 **Q41. How do you respond to Witness Coppola’s assertion in his testimony at line 19**
22 **of page 39, that these project changes represent an “excessive cost overrun” or**
23 **reflect “an imprudent and unreasonable approach to project cost**
24 **management?”**

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1 A41. I disagree. I acknowledge in my direct testimony at line 22 of JCD-46, “[t]he need
2 for and use of contingency amounts at the individual project level and at the
3 portfolio level is well understood in project management and portfolio
4 management.” However, as Witness Kindschy’s proposed reductions reinforce –
5 there is minimal grace extended to projections with potential for real world
6 uncertainty and yet, the world is an uncertain place. This paradigm leads to a
7 conclusion that projection variances in and of themselves are not evidence of
8 imprudence or unreasonable project management but rather a reasonable potential
9 outcome in some amount (higher or lower), for some project components based on
10 the case records developed by the Commission over the years.

11

12 **Q42. What are your thoughts on Witness Coppola’s questioning (line 7, page 45 of**
13 **his direct testimony) whether certain projects that you support are likely to**
14 **extend beyond the test period, yet have “annual” in-service designations are**
15 **“eligible for inclusion in rate base in this rate case?”**

16 A42. The inclusion of certain projects (Natural Draft Cooling Towers, Document
17 Management System Enhancements, Remote Monitoring) in this instant rate case
18 is fully appropriate, reasonable and prudent and represents DTE Electric’s evolving
19 Fermi 2 operations and management systems. That said project timing may move
20 should other Fermi 2 operational priorities manifest themselves through the
21 projected test period. It is fair to identify projects that have zero historical
22 expenditures and have projected expenditures only in the projected test period and
23 highlight any uncertainty in the in-service date.

24

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1 **Q43. Is complete disallowance of the projected expenditures by the Commission**
2 **appropriate for expenditures that support projects that may have their in-**
3 **service dates extend beyond the test period?**

4 A43. No. I discussed throughout my direct testimony regarding DTE Electric's nuclear
5 safety prioritization. The Commission should determine the Nuclear Generation
6 capital expenditures, in total, as presented are reasonable and prudent and are
7 consistent with Nuclear Generation's actual historical capital expenditures to safely
8 and reliably operate Fermi 2. Alternatively, an acknowledgement from the
9 Commission that the projects will be recoverable in the future once they are in-
10 service would be supportive.

11

12 **Q44. What are your thoughts concerning Witness Coppola's proposal to reduce**
13 **approximately \$24.0 million of capital expenditures for the Natural Draft**
14 **Cooling Towers, Document Management System and Remote Monitoring?**

15 A44. Witness Coppola asserts at line 11 of page 45 in his direct testimony that these
16 projects "should have identified project phases and timelines with a completion in-
17 service date" and Witness Coppola had asked for a specifically formatted project
18 status update ("i.e. needs identification, initial concept scoping, engineering design,
19 out for bids, construction, completed") in his discovery request depicted on page 2
20 of Witness Coppola's Exhibit AG-12. These phases are typically associated with a
21 phase-gate approval process. As I clarify later in my testimony, and as my discovery
22 response explains (also depicted on the same exhibit) that Nuclear Generation does
23 not use a phase-gate approval process as potentially envisioned by Witness
24 Coppola. The fact that project statuses as prescribed by Witness Coppola's

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1 discovery request are not used by Nuclear Generation does not demonstrate
2 anything whatsoever regarding reasonableness or prudence.

3

4 **Q45. Does Nuclear Generation use an “unorthodox project management approach”**
5 **as Witness Coppola suggests in his direct testimony at line 5, page 45?**

6 A45. Nuclear Generation uses nuclear work management processes to manage capital
7 projects. Witness Coppola’s assertion of “unorthodox” is unfounded as graded or
8 modified approaches to capital project management is reasonable and prudent
9 based on the scope and implementation of the capital projects. Nuclear Generation
10 does not use the phase-gate approval process potentially envisioned by Witness
11 Coppola as the majority of Nuclear Generation’s capital work is asset replacement,
12 not new construction, and though there may be a design change as I have discussed
13 in my direct testimony at line 15, page JCD-25, design change at a nuclear power
14 plant is to maintain configuration control, not to necessarily design new equipment.
15 This means that a generalized understanding of project management that may apply
16 in other fields, such as building construction, that includes steps such as (1) identify
17 problem, (2) design solution, (3) solicit material labor contracts, and (4) execute
18 work, is not necessarily applicable to an operating nuclear power plant.

19

20 For example, when a pump motor is at end of life – this pump motor must be
21 replaced because the Fermi 2 license requires the pump motor. DTE Electric
22 identifies the new pump motor (likely from the only supplier that sells such a pump
23 motor); however, the closest match to the existing pump motor is slightly different
24 in electrical draw, mechanical mounting and fitting and size and weight. DTE
25 Electric purchases the pump motor but now must perform a design change (plant

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1 modification) and update calculations to ensure the new electrical draw is
2 accounted for and the weight of the new pump motor is seismically accounted for.
3 As the design change is occurring, DTE Electric may also be performing
4 implementation tasks using its pre-approved labor suppliers.

5
6 A rigid adherence to a phase-gate approval process would result in decision-making
7 paralysis because the new pump motor must be purchased well before the design
8 would ever be completed. It is this dynamic that leads Nuclear Generation to
9 sometimes use a “partial” appropriation and then follow-up with a “full”
10 appropriation to allow solicitation, procurement, design and implementation
11 planning to all occur simultaneously at the initial stages, then as this initial work
12 progresses, the full amount of the project becomes clearer and the full appropriation
13 can be reasonably authorized. This approach is necessary, reasonable, and prudent.

14

15 **Q46. Does a project such as the Natural Draft Cooling Tower follow project**
16 **management principles?**

17 A46. Not in the manner potentially envisioned by Witness Coppola. Natural Draft
18 Cooling Towers is not a “project” in industry terms, it is a “capital maintenance
19 activity.” There are no “project phase” activities – for example, engineering is not
20 required because the assets being replaced are, in industry terms “like-for-like” and
21 thus the replacements of retirement units do not drive modification to the plant
22 when executed. As I state in my direct testimony, our suppliers have been pre-
23 selected and on-site therefore solicitation is not specific to this project. This exact
24 type of capital replacement has been performed in years past as the material

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1 condition of the cooling towers has warranted and work planning is relatively
2 straight forward.

3

4 **Q47. Would a project such as Remote Monitoring follow project management**
5 **principles?**

6 A47. Similar to the Natural Draft Cooling Tower, not in the manner potentially
7 envisioned by Witness Coppola. Remote Monitoring is not a “project” in industry
8 terms, but rather it is a “capital maintenance activity.” As I depict on page 28 of
9 Exhibit A-20, Schedule J2, the scope is the installation of equipment monitoring
10 devices. DTE Electric projects that with the completion of Plant Wireless,
11 engineering design requirements will be minimal for the 2025 scope. Though the
12 project is projected to be completed in 2026, the “annual” designation for in-service
13 is consistent with DTE Electric’s intent to place into service in 2025 those remote
14 monitoring assets installed in 2025, and then complete the initial remote monitoring
15 installation in 2026 and place the remaining balance of the assets in service then.

16

17 **Q48. Would a project such as the Document Management System follow project**
18 **management principles?**

19 A48. Not in the manner potentially envisioned by Witness Coppola. The Document
20 Management System is the purchase and addition of modules to Fermi 2’s existing
21 document management system. DTE Electric does not project plant modifications
22 or additional solicitations as the document management system is already in-use at
23 Fermi 2. For this rate case, DTE Electric projected modules for activities such as
24 automated workflow of design documents to be installed and in-service in 2025,

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1 with other modules such as paperless procedures projected to be in-service in 2026
2 – hence the “annual” designation for the in-service date.

3

4 **Q49. What are your thoughts concerning Witness Coppola’s proposal to reduce**
5 **approximately \$6.4 million of capital expenditures for the Sanitary System**
6 **project?**

7 A49. Witness Coppola asserts at line 4 of page 46 in his direct testimony that these
8 projects “should have a project plan and timeline with a stated completion date and
9 in-service date.” Also, Witness Coppola suggests at line 5 of page 46 of his direct
10 testimony: “The “Annual” in-service date designation by the Company would
11 imply an annual program, which does not appear to be correct for this project.” The
12 Sanitary system replacement project is intended to initiate and complete installation
13 of the two-pump system in 2025, where the “annual” designation is used to convey
14 that individual assets associated with the annual expenditures (in this case the two-
15 pump system noted in my direct testimony) will be in-service prior to year’s end
16 (in this case in-service in 2025). Additional expenditures to replace or reroute
17 additional portions of the sanitary system may be required – though not known at
18 this time, for this reason, my direct testimony explains project expenditures “extend
19 beyond the projected test period.”

20

21 **Q50. Does DTE Electric have any “inability or unwillingness to provide a project**
22 **timeline and current phase of development,” as Witness Coppola suggests on**
23 **page 46 of his direct testimony at line 7?**

24 A50. No. Witness Coppola had asked for a specifically formatted project status update
25 (“i.e. needs identification, initial concept scoping, engineering design, out for bids,

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1 construction, completed”) in his discovery request depicted on page 2 of Witness
2 Coppola’s Exhibit AG-12. As my discovery response explained (also depicted on
3 the same exhibit) and as I have described above, Nuclear Generation does not status
4 projects as a particular phase or in the manner requested. The sanitary sewer
5 program has no projected spend in 2024 and no historical actual spend. In non-
6 specific terms, this means the sanitary sewer project has not started and is not
7 projected to start until 2025. DTE Electric is reasonable and prudent to include the
8 Sanitary system replacement projected expenditures and there is no basis to
9 disallow the \$6.4 million of capital expenditures for the Sanitary System project
10 proposed by Witness Coppola and the Commission should not adopt Witness
11 Coppola’s proposed reduction.

12

13 **Q51. What are your thoughts concerning Witness Coppola’s proposal to reduce**
14 **approximately \$20.0 million of capital expenditures for Nuclear Fuel?**

15 A51. Nuclear Generation’s nuclear fuel expenditures are reasonable and prudent.
16 Witness Coppola’s proposal to reduce Nuclear Fuel expenditures is not reasonable
17 and not prudent and based on an incorrect inference from my discovery response
18 depicted on page 3 of Witness Coppola’s Exhibit AG-11 as well as a
19 misunderstanding about nuclear fuel projections provided in previous rate cases.

20

21 **Q52. Witness Coppola asserts on line 2, page 44 of his direct testimony at line 5 “the**
22 **Company discusses variances in the number of fuel assemblies from outage to**
23 **outage without addressing specifically the cost variance between 2023 and**
24 **2025.” Does purchasing more nuclear fuel assemblies address variance in cost**
25 **expenditures?**

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1 A52. I believe it does. Page 3 of Witness Coppola's Exhibit AG-11 shows Nuclear
2 Generation projects to purchase uranium, enrichment, and fabrication to support
3 244 nuclear fuel assemblies in 2025 for introduction into the Fermi 2 reactor core
4 in RF23 (2026); whereas Nuclear Generation only purchased uranium, enrichment
5 and fabrication to support 220 nuclear fuel assemblies in 2023 for introduction into
6 the Fermi 2 reactor core in RF22 (2024). All other factors being equal, 244 nuclear
7 fuel assemblies will have approximately 11% more total cost than 220 nuclear fuel
8 assemblies.

9

10 **Q53. Do you agree with Witness Coppola's assertion at line 7 on page 43 of his direct**
11 **testimony that DTE Electric's "calculation is in accordance with industry**
12 **accepted software and rules, without providing further explanation or support**
13 **for the calculation"?**

14 A53. No. In addition to the change in the number of nuclear fuel assemblies discussed
15 above, Page 3 of Witness Coppola's Exhibit AG-11 a discovery response from the
16 Company states that nuclear fuel expense is, in part, "an outcome of a reasonable
17 and prudent analysis of the nuclear fuel cycle components and *contract terms*
18 *applied* to the projected Fermi 2 nuclear core design requirements, consistent with
19 the Company's 2024 PSCR Plan U-21425." (emphasis added). In support of the
20 Company's 2024 PSCR Plan Case No. U-21425, DTE Electric Witness Wines
21 discussed how nuclear fuel projections are developed including use of relevant
22 electricity generation plans, nuclear fuel bundle loading quantities and nuclear fuel
23 cycle component prices; Witness Wines also discussed the status of DTE Electric's
24 nuclear fuel cycle contracts. The Company's 2024 PSCR Plan and 5-year forecast

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1 have been approved in Case No. U-21425 by the Commission's Order dated July
2 23, 2024.

3

4 **Q54. Witness Coppola asserts at line 1, page 44 of his direct testimony that DTE**
5 **Electric “has a propensity to overestimate the cost of nuclear fuel.” What are**
6 **your thoughts concerning Witness Coppola’s historical analysis of DTE**
7 **Electric’s nuclear fuel costs?**

8 A54. I will first introduce Exhibit A-47, Schedule LL2 Nuclear Fuel Expenditures.
9 Column (a) of Exhibit A-47, Schedule LL2 are recent DTE Electric rate cases,
10 column (b) describes the expenditure, in this instance total nuclear fuel, columns
11 (c) through (j) depict the level of total nuclear fuel expenditure DTE Electric
12 provided in the rate case (exhibits and associated workpapers) listed in column (a),
13 and I denote with an “A” those expenditure amounts depicted were actual historical
14 amounts and not projected. Column (k) is the sum of the projected nuclear fuel
15 expenditures for the rate case list in column (a) and column (l) is the sum of the
16 total historical actual expenditures for the same projection period (note: 2024 is not
17 complete and uses the projected amount) and used in column (k), such that
18 comparing columns (k) and (l) is valid.

19

20 Exhibit A-47, Schedule LL2 demonstrates that DTE Electric has historically
21 provided reasonable and prudent nuclear fuel expenditure projections. For example,
22 Witness Coppola himself highlights that the nuclear fuel projection in DTE Electric
23 rate Case No. U-20836 for 2021 nuclear fuel expenditures was approximately
24 \$122.7 million with actual nuclear fuel expenditures being \$120.1 million (line 14
25 on page 43 of direct testimony) or within 2%; DTE Electric’s projected 2023

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1 nuclear fuel expenditures for 2023 in Case No. U-20836 were \$111.0 million with
2 actual nuclear fuel expenditures being \$110.1 million or within 1%. As I depict at
3 line 9, column (k) of Exhibit A-47, Schedule LL2, the total projected nuclear fuel
4 expenditures provided in Case No. U-20836 (Calendar years 2021, 2022 and 2023)
5 were \$233.9 million with actual total nuclear fuel expenditures for the same period
6 at \$233.4 million.

7

8 **Q55. Witness Coppola converts the \$117.4 million total nuclear fuel expenditures**
9 **projected for 2023 in DTE Electric Case No. U-21297 to \$128.1 million by**
10 **asserting “the Company forecasted \$117,421,000 for 11 months of costs for**
11 **nuclear fuel which annualized means it had forecasted \$128,100,000 for the**
12 **entire year” at line 16 of page 43 of his direct testimony. Did DTE Electric**
13 **project approximately \$128.1 million for nuclear fuel expenditures for the 12-**
14 **months ending December 31, 2023, in DTE Electric rate Case No. U-21297?**

15 **A55. No. In DTE Electric rate Case No. U-21297, DTE Electric projected \$117.4 million**
16 **for the 12-month period ending December 31, 2023. Witness Coppola is correct in**
17 **his recollection that the DTE Electric rate Case No. U-21297 did use a bridge period**
18 **that included the 11 months ending November 30, 2023, but Case No. U-21297**
19 **also included the subsequent 12-month period ending November 30, 2024, as the**
20 **projected test period which only projected \$0.2 million of nuclear fuel expenditures.**
21 **DTE Electric’s total projected nuclear fuel costs for the 23-month period ending**
22 **November 30, 2024, was only approximately \$117.6 million, not \$128.1 million as**
23 **Witness Coppola mistakenly asserts.**

24

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1 **Q56. How do the total nuclear fuel expenditures depicted at line 10, page 1 of**
2 **Exhibit A-12, Schedule B5.3 (Case No. U-21534) compare to the total nuclear**
3 **fuel expenditures depicted at line 10, page 1 of Exhibit A-12, Schedule B5.3**
4 **(Case No. U-21297) then for the period ending November 30, 2024?**

5 A56. DTE Electric's total nuclear fuel expenditures depicted in Exhibit A-12, Schedule
6 B5.3 (U-21534) for the 23-month period ending November 30, 2024, is \$112.0
7 million. As I depict in Exhibit A-47, Schedule LL2 at line 10, column (k), the
8 previous rate case (Case No. U-21297) total nuclear fuel expenditures for the same
9 23-month period ending November 30, 2024, was \$117.7 million. The variance
10 between the two rate cases is approximately 4%.

11

12 **Q57. In DTE Electric's rate Case No. U-20162, DTE Electric projected total nuclear**
13 **fuel expenditures for 2018 and 2019. How did the historical actual**
14 **expenditures compare?**

15 A57. Recall, these expenditures support an 18-month fuel cycle. As I depict in Exhibit
16 A-47, Schedule LL2, at line 7, column (k,) DTE Electric's Case No. U-20162 total
17 nuclear fuel expenditure projections totaled \$152.0 million for the calendar years
18 2018 and 2019 and had historical actuals of \$150.5 million (depicted at line 7,
19 column (l)). The net variance between the U-20162 total nuclear fuel expenditure
20 projections and actual total nuclear fuel expenditures were less than 1%.

21

22 **Q58. In DTE Electric's rate Case No. U-20561, DTE Electric projected total nuclear**
23 **fuel expenditures for 2019 through 2021. How did the historical actual**
24 **expenditures compare?**

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1 A58. Recall, these expenditures support an 18-month fuel cycle. As I depict in Exhibit
2 A-47, Schedule LL2, at line 8, in DTE Electric rate Case No. U-20561, DTE
3 Electric projected \$83.5 million, \$0.1 million and \$114.4 million of nuclear fuel
4 expense for calendar years 2019, 2020 and 2021 respectively for a total projected
5 nuclear fuel expenditures total of \$198.0 million as depicted at line 8, column (k).
6 DTE Electric had actuals of \$78.0 million, \$0.3 million and \$120.1 million of
7 nuclear fuel expense for calendar years 2019, 2020 and 2021 respectively for a total
8 actual nuclear fuel expenditures total of \$198.4 million depicted at line 8, column
9 (l). The net variance between the three years is less than 0.5%.

10

11 **Q59. What do you conclude from your analysis of DTE Electric's historical**
12 **projections for nuclear fuel expenditures?**

13 A59. DTE Electric's nuclear fuel expenditure projections are reasonable and prudent.
14 Variances to the historical nuclear fuel expenditures have been immaterial and there
15 is a historical basis to be confident that DTE Electric's projected nuclear fuel
16 expenditures are accurate and very likely to be incurred as projected.

17

18 **Q60. Witness Coppola points to historical nuclear fuel expenditures of \$120.1**
19 **million in 2021 and \$110.0 million in calendar years 2021 and 2023 respectively**
20 **to assert that the average nuclear fuel expenditure of \$115.1 million is the**
21 **reasonable and prudent amount of 2025 expenditure for Fermi 2's nuclear fuel**
22 **(at line 10, page 43 of his direct testimony). Is Witness Coppola's analysis**
23 **consistent with how nuclear fuel projections are formulated?**

24 A60. No. The operational history of Fermi 2 renders this type of analysis invalid. Reactor
25 core design and nuclear fuel projections are not straightforward calculations but

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1 rather are dependent on the operational history of the reactor. The analysis of how
2 many nuclear fuel assemblies to replace each refueling outage requires specialized
3 education, training, and specific regulatory-approved software.

4
5 To help simplify the discussion – Nuclear fuel must be loaded into the reactor core
6 to sustain electricity generation operations through to the next refueling outage
7 where it's a given that the longer the time between the end of one refueling outage
8 and the start of the next refueling outage, the more nuclear fuel must be consumed
9 to sustain that operating cycle. Because Fermi 2 Refueling Outage 20 (RF20) had
10 a duration of approximately 138 days, and RF21 had a duration of approximately
11 98 days, DTE Electric was able to replace fewer nuclear fuel assemblies than the
12 equilibrium amount of 240 nuclear fuel assemblies to sustain the 2022 – 2024
13 operating cycle, where equilibrium amount means the number of nuclear fuel
14 assemblies calculated to be replaced every refueling outage assuming the reactor is
15 operated repeatedly to the same cycle plan. The planned RF22 duration was near
16 the equilibrium assumption of 45 days, which results in DTE Electric not only
17 replacing the equilibrium number of 240 nuclear fuel assemblies but also
18 incremental nuclear fuel assemblies to account for the nuclear fuel assemblies DTE
19 Electric did not have to replace in prior refueling outages.

20

21 **Q61. What is your recommendation to the Commission regarding Witness**
22 **Coppola's proposed reduction of approximately \$20.0 million for nuclear fuel**
23 **expenditures?**

24 A61. I recommend the Commission not adopt Witness Coppola's proposal to reduce
25 nuclear fuel expenditures by \$20.0 million. DTE Electric demonstrates that nuclear

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1 fuel expenditure projections are reasonable and prudent given the approved
2 methodology for the projected number of fuel assemblies. DTE Electric also
3 demonstrates the change in the projected number of fuel assemblies relative to past
4 operational cycles is reasonable and prudent given Fermi 2's operational history,
5 and DTE Electric has demonstrated its past nuclear fuel projections have been
6 reasonable, prudent, and accurate.

7

8 **Q62. Does this conclude your rebuttal testimony?**

9 A62. 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-21534

REBUTTAL TESTIMONY

OF

SATVIR S. DEOL

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF SATVIR S. DEOL

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Satvir S. Deol (he/him/his), and my business address is One Energy
4 Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company
5 (DTE Electric or Company).

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.
10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of this testimony is to rebut certain positions and recommendations for
14 disallowances of capital projects as proposed by certain witnesses that provided
15 direct testimony in the instant case. These witnesses include:

- 16 • Michigan Attorney General (AG), Michigan Environmental Council
17 (MEC), Natural Resources Defense Council (NRDC), collectively referred
18 to as "AG-MN" Witness Stephens
- 19 • Ann Arbor Witness Stults
- 20 • Detroit Area Advocacy Organizations (DAAO) Witness Koeppel
- 21 • Michigan Attorney General (AG), Michigan Environmental Council
22 (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), and
23 Citizens Utility Board of Michigan (CUB), collectively referred to as
24 "MNSC" Witness Woolley

Line
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- 1 • Association of Businesses Advocating Tariff Equity (ABATE) Witness
2 York

3 The absence of a discussion of other matters in my rebuttal testimony should not
4 be taken as an indication of agreement with other aspects of any intervenor's
5 testimony.

6

7 **Q4. Are you sponsoring any exhibits in this proceeding?**

8 A4. Yes. I am sponsoring the following exhibits:

9	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
10	A-50	OO1	Discovery Response MNSCDE-5.5a(S1)
11	A-50	OO2	NDA CEII MNSCDE-5.5a(S1) –
12			Subtransmission Load Data
13	A-50	OO3	Discovery Response MNSCDE-8.5a

14

15 **Q5. Were these exhibits prepared by you or under your direction?**

16 A5. Yes, they were.

17

18 **Q6. How is your testimony organized?**

19 A6. There are eight specific topics I will rebut in my testimony, as listed below. A
20 detailed discussion of why the intervenor's recommendations should not be
21 accepted by the Commission follows.

22

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1 **Part I: Conversions**

2

3 **Q7. Which intervenors offer testimony regarding circuit conversions that you wish**
4 **to rebut?**

5 A7. AG-MN Witness Stephens challenges the overall justification for conversion
6 projects. DAAO Witness Koeppel offers testimony claiming there is conflict
7 between my direct testimony and that of Company Witness Kryscynski regarding
8 City of Detroit Infrastructure (CODI) conversions. I address Witness Stephens and
9 Witness Koeppel in Rebuttal Topic 1 and Rebuttal Topic 2, respectively.

10

11 **Rebuttal Topic 1: AG-MN Witness Stephens' claims regarding the Company's**
12 **conversion programs**

13 **Q8. What does Witness Stephens recommend with respect to the Company's**
14 **circuit conversions program?**

15 A8. Witness Stephens does not recommend any specific disallowance of the Company's
16 capital expenditures in the instant case, however he does recommend that the
17 Commission reject the Company's proposal to include conversions in the 2026 and
18 2027 IRM¹. Company Witness Foley's rebuttal testimony, page 21, line 18 through
19 page 24, line 23, in the instant case addresses the 2026 and 2027 IRM.

20

21 Related to his analysis of the Company's circuit conversions program, Witness
22 Stephens also makes other recommendations and statements as summarized below
23 that I will cover in my rebuttal:

¹ Stephens DT, p. 23, lines 13-14

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- 1 • Witness Stephens recommends that the Company support the pace at which
- 2 it plans to convert its 4.8 kV. He additionally states that the Company's
- 3 justification of reliability, safety, and capacity does not support the 15-year
- 4 goal stated in the DGP². Witness Stephens also states that the Commission
- 5 should direct the Company to solicit an independent expert to assess the
- 6 appropriate rate of conversions³.
- 7 • Witness Stephens states that the Company lacks transparency in the
- 8 information provided regarding its capital expenditures⁴.
- 9 • Witness Stephens recommends that the Commission require the Company
- 10 to establish and present metrics, such as dollars per circuit mile converted
- 11 in future rate cases⁵.
- 12
- 13 Other statements and recommendations in Witness Stephens' assessment of the
- 14 Company's circuit conversions program that are addressed more generally in other
- 15 Company witness's rebuttal testimonies are as follows:
- 16 • Witness Stephens states the Company must provide an independent analysis
- 17 showing its EV adoption forecasts are likely, that its assumptions about EV
- 18 charging behavior are accurate, and that these forecasts and assumptions are
- 19 associated with geographies, substations, and circuits⁶. Company Witness
- 20 Bennett's rebuttal testimony, Topic 6 [EV Forecast], in the instant case
- 21 addresses these recommendations.

² Stephens DT, pp. 18 - 20

³ Stephens DT, p. 23, lines 14-16

⁴ Stephens DT, pp. 20 - 23

⁵ Stephens DT, p. 24, lines 1 – 3

⁶ Stephens DT, p. 23, lines 16 – 20

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1 • As part of his assessment of the Company’s pace of circuit conversions,
2 Witness Stephens states the Company has not provided a benefit-cost
3 analysis (BCA)⁷. He also argues that the Company’s investments in circuit
4 conversions, along with other initiatives, are “discretionary” work that has
5 not been adequately supported⁸. Company Witness Kryscynski’s rebuttal
6 testimony in the instant case addresses these claims in Rebuttal Issue 2
7 [“Discretionary”] and Rebuttal Issue 5 [BCA].

8

9 **Q9. What does Witness Stephens believe regarding the pace and 15-year**
10 **timeframe at which the Company plans to convert its 4.8 kV circuits?**

11 A9. Witness Stephens argues that “as DTE likely built these circuits over a 50-year
12 period from 1900 to 1950, rebuilding all these circuits in 15 years is an
13 unreasonable aspiration⁹.”

14

15 **Q10. Is Witness Stephens’ reference to the initial building of the 4.8kV grid in**
16 **southeast Michigan relevant to the current customer needs driving the timing**
17 **of the Company’s conversion program?**

18 A10. No. Different customer drivers determined timing of the initial grid build such as
19 population growth in the early Michigan population centers and the eventual
20 development of rural areas. In contrast, the Company’s current conversion
21 investments are being driven by increasing electric capacity needs, system
22 performance caused by aging infrastructure, and potential public safety hazards of
23 an ungrounded 4.8kV delta system.

⁷ Stephens DT, p. 18, lines 2 – 3

⁸ Stephens DT, p. 45

⁹ Stephens DT, pp. 17 – 18

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1 **Q11. Why has the Company developed a goal of converting its remaining aged**
2 **4.8kV circuits in 15 years?**

3 A11. The 15-year conversion goal is a directional target and may change in timing and
4 priority as specific grid needs evolve in different geographic areas and circuits. In
5 Case No. U-20147 the Commission requested that the Company provide a long
6 term (15 year) vision of the grid stating:

7

8 “Therefore, the Commission directs DTE electric, Consumers, and I&M to
9 continue to develop detailed distribution plans over a five-year period, but also
10 include in the plan their vision and high-level investment strategies 10 and 15 years
11 out.¹⁰”

12

13 This 15-year conversion directional goal was developed as part of the Company’s
14 long-term vision for the grid. However, the customer needs of a safer, more reliable,
15 and resilient grid, with more capacity to support electrification are important now,
16 and not expected to diminish over time. Ultimately, the grid will be rebuilt at a pace
17 required to support customer needs and affordability. The conversion investments
18 in this case are supported by near-term drivers highlighted in my testimony, such
19 as capacity needs, reliability improvements, and addressing aging and end of life
20 infrastructure.

21

22 **Q12. What does Witness Stephens claim regarding the customer reliability as it**
23 **relates to conversion of aged 4.8kV circuits?**

¹⁰ MPSC Order in Case No. U-20147 dated September 11, 2019, p. 4

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1 A12. Witness Stephens claims “[r]eliability improvement is not a reasonable justification
2 because data the Company provided in discovery in U-21297 shows the reliability
3 of 13.2kV circuits (as measured by system average interruption duration without
4 major event days) was worse during 2018- 2022 (124 minutes) than the reliability
5 of 4.8kV circuits over the same time period (97 minutes)¹¹.”

6

7 **Q13. Do you agree with Witness Stephens’ claim regarding the lack of customer**
8 **reliability improvements that occur with circuit conversions?**

9 A13. I do not agree with Witness Stephens’ conclusion for the following reasons. First,
10 while the estimated reliability benefits vary with the specific data for each circuit
11 and project, for the conversions that are included in the instant case, the average
12 projected reliability improvement is estimated to be up to 90% as stated on page 14
13 of my direct testimony.

14

15 Secondly, Witness Stephens arrived at the incorrect assertion that 13.2kV circuits
16 had poorer reliability performance than 4.8kV circuits by examining the more
17 narrowly defined SAIDI ex-MED. In reality, for the same period of time, customers
18 served from 13.2kV circuits experienced 17% better performance than those served
19 from 4.8kV circuits when one takes in to account the all-weather SAIDI, as shown
20 in Table 1 below.

21

22

Table 1 All Weather SAIDI Average 2018 – 2022

Circuit Voltage	4.8kV	13.2kV
SAIDI Minutes	623.2	514.8

¹¹ Stephens DT, p. 18, lines 14 – 19

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1 Finally, a simple comparison of 4.8kV versus the existing 13.2kV system is not
2 indicative of the reliability improvement benefits expected from current 4.8kV
3 conversion projects. The 13.2kV circuits that were built decades ago are not
4 constructed to the same standards and specifications as the more resilient 13.2kV
5 circuits the Company constructs today. The updated Grade B construction standard
6 used in the current conversion projects includes more reliable insulators with
7 polymer material that provide greater leakage current protection compared to the
8 existing porcelain insulators, fiberglass crossarms instead of wood (or armless)
9 with greater mechanical and structural loading strength, larger and stronger wood
10 or in some cases steel or concrete poles for truck-accessible circuit backbone and
11 highway crossings, and larger, higher-strength wires which all factor into
12 improving resiliency in the face of storms and overall reliability performance.
13 Furthermore, conversions provide added benefits of greater load carrying capacity,
14 increased connection points between adjacent 13.2kv circuits, and circuit
15 automation with loop-schemes will provide dramatic improvements in reliability
16 and resiliency performance with much quicker restoration of service during outage.
17

18 **Q14. Does witness Stephens agree with the Company that improved safety supports**
19 **the need to convert the aged 4.8kV system with conversions?**

20 A14. No. Witness Stephens states, “as described in the DTE’s 4.8kV Hardening
21 program, the design of the Company’s 4.8kV circuits likely increases the risk that
22 a downed conductor will remain energized if it falls to the ground¹².” In this
23 statement Witness Stephens indicates that he understands the public safety risk
24 associated with a downed conductor of a 4.8 kV ungrounded delta system. He then

¹² Stephens DT, p. 19, lines 2 – 4

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1 goes on to state, “however, this is a design condition that has existed on the
2 Company’s 4.8kV circuit since they were constructed, likely between 75 and 120
3 years ago¹³.” Despite acknowledging the associated safety hazards to customers
4 and company employees of the ungrounded 4.8 kV delta system, Witness Stephens
5 then dismisses this safety hazard solely because these 4.8kV circuits have been in
6 place for a long time.

7

8 **Q15. Does the Company agree with Witness Stephens’ assessment of safety of the**
9 **aged 4.8 kV ungrounded delta system?**

10 A15. No. The Company disagrees with Witness Stephens’ assessment and believes that
11 reducing the risk associated from potential energized downed wires of the 4.8 kV
12 ungrounded delta circuits should be a major focus and a justification for converting
13 the 4.8 kV circuits. The Company does not believe that the circuit design existing
14 for 75 to 125 years is a reasonable justification for slowing down its pace of
15 conversions.

16

17 **Q16. What does Witness Stephens state about the benefits of capacity in circuit**
18 **conversions?**

19 A16. Witness Stephens states that “circuits with peak loads above or near equipment
20 ratings should be prioritized for conversion first¹⁴.” Witness Stephens also alludes
21 that the Company only has a small percentage of 4.8kV circuits that exceed day-to-
22 day rating (5.7%) and that this is not a sufficient justification for the pace of
23 conversions¹⁵. He goes on to state that the Company should synch the focus of

¹³ Stephens DT, p. 19, lines 4 – 6

¹⁴ Stephens DT, p. 19, lines 10 – 11

¹⁵ Stephens DT, p. 19, lines 9 – 10

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1 near-term conversions to those areas where 4.8kV substations are over firm, where
2 there are circuit overloads, and where there are increased requests for electric
3 service either via new business or electrification¹⁶.

4

5 **Q17. Does the Company agree with Witness Stephens' assessment of the Company's**
6 **justification for converting 4.8kV circuits based on circuit loading?**

7 A17. In part. The Company agrees that conversions should be prioritized based on
8 loading, however, this is only one of several factors to consider when prioritizing
9 circuit conversions. Other factors, as included in my direct testimony, are safety
10 and reliability. The Company disagrees with Witness Stephens' assessment that is
11 based on day-to-day loading data for one year, 2022. One must examine circuit
12 loading trends over time, as well as the other metrics of peak capacity, and the
13 number of substations/circuits that are over their firm rating. Additionally, the
14 Company must maintain a capacity margin for operating the system during
15 maintenance and trouble events. This includes not just day-to-day circuit capacity,
16 but also the source substation capacity¹⁷, and circuit emergency ratings, which all
17 impact the ability to operate the system during planned or unplanned outage events
18 as well as the ability to support load growth. As stated in the Company's 2023 DGP
19 filing, the Company prioritizes near-term conversions from a capacity standpoint
20 in those areas where 4.8kV substations are over firm, where there are circuit
21 overloads¹⁸. The Company also takes into account areas where there are increased
22 requests for electric service either via new business or electrification.

¹⁶ Stephens DT, pp. 19 – 20

¹⁷ 20% of the Company's 4.8kV substations operate over firm rating.

¹⁸ 2023 DGP, Ex A-23, Sch. M8, pp. 119-121

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1 **Q18. What is your response to Witness Stephens' recommendation that the**
2 **Commission should direct the Company to solicit an independent review of its**
3 **planned rate of conversions?**

4 A18. Pursuant to the Commission's order in Case No. U-21305, a broader independent
5 third-party review of the Company's electric distribution system including system
6 performance and investment plans is already underway. The Company believes that
7 Witness Stephens' recommendation should be disregarded since an additional
8 third-party review will be redundant to the currently in progress audit and
9 premature.

10

11 **Q19. Does Witness Stephens make an apples-to-apples comparison across the**
12 **Company's documents provided in the instant case?**

13 A19. No, he does not. Witness Stephens uses the 4.8kV CC: Almont Relief Circuit
14 Conversion (Midas) project to demonstrate what he calls a lack of transparency in
15 the Company's conversion projects. In this example, he acknowledges that in the
16 instant case, the Company indicates a total project cost of \$30.7 million¹⁹. Witness
17 Stephens then compares this \$30.7 million to a section of the capital appropriation
18 request form (CARF) showing \$36.2 million²⁰.

19

20 The section of the CARF that includes this \$36.2 million is indicated by the red box
21 in Figure 1 below and is intended for internal Company review. The correct figure
22 in the CARF to compare against is the \$30.3 million project approval indicated by
23 the green box in Figure 1 below. It should also be noted that per the
24 recommendations made by ALJ in Case No. U-21297, the Company is now

¹⁹ Stephens DT, p. 21

²⁰ Stephens DT, p. 22, lines 5 – 6.

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1 including the total projected cost of its projects in the instant case²¹. This is set forth
2 in Exhibit A-23, Schedule M6 in the instant case where each project discussed
3 includes an estimated total project cost along with the annual forecast schedule
4 through the bridge and projected test periods. This is where Witness Stephens
5 identified the \$30.7 million total projected cost for the Midas project as shown in
6 Figure 2 below.

7

8 **Q20. Does the Company demonstrate transparency across the documents provided**
9 **in the instant case?**

10 A20. Yes, it does. The Midas project example that Witness Stephens uses in his direct
11 testimony demonstrates there is transparency across the documents presented by
12 the Company in the instant case. Witness Stephens seems to misunderstand the
13 information presented on (1) the CARF shown in Figure 1 below, (2) page 10 of
14 Exhibit A-23, Schedule M6, and (3) page 15, line 41 of Exhibit A-12, Schedule
15 B5.4.

16

17 As shown in Figures 1 and 2 below, the Company approved \$30.3 million for the
18 Midas project in the 2021 CARF and has identified an updated project forecast in
19 the instant case of \$30.7 million (Sch. M6). In Exhibit A-12, Schedule B5.4, page
20 15, line 41, the line item for the Midas project, the Company has identified 2022
21 actual spend of \$13.1 million and forecasted annual spend of \$3.9 million in 2023,
22 \$6.0 million in 2024, and \$1.0 million in 2025, or a total of \$24.1 million in the
23 instant case period. In Case No. U-21297, the Company identified \$5.6 million of
24 actual 2021 spend²² and in Case No. U-20836, the Company identified \$0.5 million

²¹ MPSC Order in Case No. U-21297, dated December 1, 2023, p. 84

²² MPSC Case No. U-21297, Ex. A-12, Sch. B5.4, p. 10, line 57

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1 of actual spend in 2020²³. It is evident that the Company has not provided annual
2 spending “for only about \$11 million of this project” as Witness Stephens claims²⁴.

3

4 **Figure 1 : 4.8kV CC Almont Relief and Circuit Conversion (Midas)**

5

CARF

Appropriation Request Summary Sheet

Project Name:	Midas Subs - Below grade, Conduit Midas Subs - Above grade, OH, Cable	Capital Budget / Project #:	I-000404-0027 (MEP) I-000801-0001 (DO)
Utility/Non-Utility:	Utility	Project Type:	Distribution
Business Segment:	Electric Utility	Business unit within budget?:	Yes
Business Unit:	MEP / DO	Project Start Date:	Mar-2019
Project Sponsor:	Joi Harris / Sharon Pfeuffer	In-Service Date:	2022, 2023
		Post Investment Evaluation Date:	2025

Current Approval Request (\$Millions):	\$28.9
Previous Request(s) (\$Millions):	\$1.4
Total Project (\$Millions):	\$30.3

Financial Summary (\$Millions)

	2020 & Prior Years	2021	2022	2023	2024	2025	Beyond	Total
Current Capital Approval Request	\$0.0	\$21.3	\$6.3	\$1.3	\$0.0	\$0.0	\$0.0	\$28.9
Previous Request(s)	0.8	0.6	0.0	0.0	0.0	0.0	0.0	1.4
Total Project Request	0.8	21.9	6.3	1.3	0.0	0.0	0.0	30.3
Operating After-Tax Cash Flow	(679)	(17,017)	(10,235)	2,811	2,828	2,723	50,892	31,323
Net Income	17	310	1,185	1,448	1,395	1,340	19,921	25,616

Hurdle Rate	IRR	NPV	Payback(years)	First 5 Yrs Avg. Net Income	Customer cost (savings)*
6.1%	6.1%	\$264	15	\$ 871	\$36,182

Project Description and Approval

The purpose of this request is to obtain full appropriation for the Midas project.

MEP Project Scope:

- Design a new 120kV to 13.2kV Class RR substation (Midas) in Almont Township
- Construct all below grade elements of the new Midas substation
- Create Class R standards as part of the substation design
- Design and install all new system conduit to facilitate the OH circuit work starting outside of substation property

DO Project Scope:

Construct the above grade elements of the new Midas Class RR substation including testing and commissioning. Substation includes two (2) 15/20/25 120 - 13.2 kV transformers and four (4) line positions, Class RR. The future Midas substation will have provisions for expansion to a Class A substation with installation of a future (12) position PDC. Also included is the transfer and partial conversion of two (2) existing Almont 4.8 kV distribution circuits to four (4) future Midas circuits with both 13.2 and 4.8 kV service. After transfer of the Almont circuits to Midas, the existing Almont substation will be de-commissioned.

6

²³ MPSC Case No. U-20836, Ex. A-12, Sch. B5.4, p. 10, line 56

²⁴ Stephens DT, p. 21, lines 15 – 16

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Figure 2 : Midas Capital Project Detail from Ex. A-23, Sch. M6

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail – Infrastructure Redesign and Modernization

Case No: U-21534
Exhibit: A-23
Schedule: M6
Witness: S. S. Deol
Page: 10 of 404

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

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

2

3 **Q21. What is your response to Witness Stephens’ recommendation that the**
4 **Commission require the Company to “establish and present in its next rate**
5 **case metrics, such as dollars per circuit mile converted, to budget and monitor**
6 **circuit conversion costs²⁵?”**

7 A21. The Company disagrees with this recommendation. Conversion projects are
8 complex, and each project is unique and includes a number of factors including, but
9 not limited to, customer density, circuit pole density, substation layout design,
10 access limitations, etc. The Company believes that the variations inherent in
11 projects with very different scopes make a proposed “one-size-fits-all” metric such
12 as standard cost per mile converted of limited value.

²⁵ Stephens DT, p. 24, lines 1 – 3

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**Rebuttal Topic 2: DAAO Witness Koeppel's characterization of the City of
Detroit Infrastructure (CODI) program**

Q22. What does Witness Koeppel recommend with respect to the Company's CODI program?

A22. Witness Koeppel recommends that the Commission reject or substantially reduce the Company's capital expenditures on the CODI program²⁶. The Company's capital expenditures between the historical test year, bridge period, and test year are \$49.8 million, \$198.2 million, and \$48.4 million respectively, or \$296.4 million total²⁷.

Witness Koeppel also recommends that the Commission require the Company "to analyze changes in demographics over time when assessing the equity impacts or its proposed investments" and that "the Commission should require the use of regression analysis to have a complete understanding of equity outcomes along lines of race and class²⁸."

Q23. What does Witness Koeppel claim with respect to the Company's proposed CODI investments in the instant case for which he recommends disallowance?

A23. Witness Koeppel claims that the Company's equity analysis of its infrastructure redesign and rebuild projects is flawed and contradicts the support for the CODI projects discussed in my direct testimony. Company Witness Kryscynski's rebuttal testimony in the instant case, Rebuttal Issue 11, addresses Witness Koeppel's misinterpretation of the Company's equity analysis.

²⁶ Koeppel DT, p. 47, lines 4 – 6

²⁷ Summation of all CODI projects in Ex. A-12, Sch. B5.4, pp. 14 & 16, lines 28 – 36 and 79 – 82

²⁸ Koeppel DT, p. 47, lines 6 – 9

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2 **Q24. Has Witness Koeppel mischaracterized information presented in the instant**
3 **case by the Company regarding the CODI program?**

4 A24. Yes, he has. Witness Koeppel attempts to draw correlations between population
5 density and electrical system reliability performance. The CODI footprint is
6 outlined by him to show that it has better reliability performance (SAIDI) than
7 surrounding areas presumably because the population density is higher. However,
8 the SAIDI performance relative to surrounding areas is better because it is a
9 predominantly all-UG area in a dense urban environment, whereas the surrounding
10 areas outside of CODI are fed by overhead circuits. In fact, the CODI boundary
11 Witness Koeppel draws over the system in “Figure 2: CODI Program Outline from
12 SAIDI (sic) Census Tract” shows significantly worse reliability in the outer edges
13 of the geographic area where some overhead does exist within the footprint²⁹.

14

15 **Q25. What is your response to Witness Koeppel’s claim that the Company’s**
16 **rationale for its proposed CODI expenditures contradicts its own equity**
17 **analysis?**

18 A25. The CODI projects were specifically developed as their own initiatives due to the
19 uniqueness of the systems within its footprint as explained on page 29 of my direct
20 testimony: “The CODI area is served primarily by an all-underground system with
21 manhole access located in busy city center streets. Its reliability is dependent upon
22 the ability to have redundant capacity available on all power lines to transfer load
23 in the event of cable failures or planned shutdowns on the distribution and
24 subtransmission systems.” The drivers for the CODI projects were not wholly

²⁹ Koeppel DT, p. 46, Figure 2

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1 driven by reliability improvement, but on the need to address capacity for load
2 growth, maintaining sufficient redundancy to ensure reliability as outlined above,
3 and addressing aging infrastructure. It is not appropriate to compare the project
4 drivers and reliability performance of an all-underground system with an overhead
5 system, as the two are drastically different in age, design, and the environment in
6 which they exist and are maintained.

7

8 **Q26. Should the Commission consider benefits not only to customers in the**
9 **immediate CODI area, but benefits to customers served by those facilities in**
10 **the Company's broader service territory?**

11 A26. Yes, it should. The customer base in the CODI area is not only the new high-profile
12 developments highlighted in my testimony, but also includes many important
13 customers critical to the health and well-being of the entire City of Detroit
14 populace. The CODI area includes multiple governmental, educational,
15 transportation, entertainment, and health and wellness institutions that benefit all
16 residents in Detroit and the larger Southeast Michigan Region. Aside from the
17 multiple City of Detroit municipal offices that are located downtown, Wayne State
18 University, The Detroit Medical Center, Henry Ford Hospital, Detroit Receiving
19 Hospital, McNamara Federal Building, Detroit Public Safety Headquarters,
20 Michigan Science Center, Charles H. Wright Museum of African American
21 History, The Detroit Institute of Arts, Wayne County Criminal Justice Complex,
22 Fox Theater, Detroit Opera House, Detroit Music Hall, Ford Field, Comerica Park,
23 are just a few of the other important customers located in the CODI footprint.
24 Investment in the electrical infrastructure in the CODI footprint will benefit all
25 citizens of the City of Detroit and the surrounding communities.

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2 **Q27. Is there a better comparison to be made about the need for project**
3 **improvements as it relates to the reliability of the CODI area?**

4 A27. Yes, there is. A more relevant comparison to be made would be to other cities with
5 urban all underground systems and the industry reliability performance. As noted
6 on page 33 of my direct testimony: “The downtown Detroit AC Network has
7 experienced customer outages 22 times since 2016 or an average of 2.75 outages
8 per year. This is concerning, as AC Network systems normally provide reliability
9 that exceeds radial systems.

10

11 Typically, a network customer can expect to be out of service once every 58 years
12 and experience 4% of the interruptions of a radial underground system (New York
13 Public Service Commission, 2009 as quoted in Smith & Moffat 2010)”. This data
14 puts into context how the aged network infrastructure in the CODI footprint is
15 already approaching the end-of-life bathtub curve with failure rates and reliability
16 that drastically underperforms similar systems in the industry. This drives home
17 the importance of an accelerated initiative to address the issue to rebuild and
18 maintain the integrity of the system prior to the exponential escalation of large-
19 scale failures. This trend is similar to the experiences of other utilities such as
20 Indianapolis Power & Light (IPL), Pepco, and Southern California Edison (SCE)
21 that have experienced catastrophic failures on their urban network system leading
22 to large scale and pro-longed outages and manhole events³⁰.

³⁰ Indianapolis Power & Light Report, available at
https://secure.in.gov/iurc/files/IPL_Downtown_Network_Audit_Report_-_Final_Report1.pdf, accessed
August 12, 2024

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1 The CODI projects address these concerns through conversions, while also
2 increasing capacity and decommissioning aging 4.8kV and 24 kV infrastructure.
3 With the higher 13.2kV distribution voltage class and direct ties to 120kV sources,
4 the system ultimately ends up with significantly less infrastructure to operate and
5 maintain going forward.

6

7 **Q28. What should the Commission find with respect to Witness Koeppel's**
8 **recommendation to disallow the Company's \$296.4 million in capital**
9 **expenditures for the City of Detroit Infrastructure conversion program?**

10 A28. The Commission should find that Witness Koeppel's claim that the Company's
11 investments to improve the City of Detroit Infrastructure do not offer benefits to
12 the residents of Detroit to be unjustified and based on a mischaracterization of
13 information presented by the Company in the instant case. Therefore, Witness
14 Koeppel's recommendation to disallow the CODI expenditures should be
15 disregarded.

16

Potomac Electric Power Company Report, available at
<https://edocket.dcpsec.org/apis/api/Filing/download?attachId=7765&guidFileName=894021a2-eb62-4668-bb48-0a90ea0f492a.pdf>, accessed August 12, 2024

Southern California Edison Long Beach AC Network Outage Report, available at
https://newsroom.edison.com/internal_redirect/cms.ipressroom.com.s3.amazonaws.com/166/files/201510/Report%20on%20the%20SCE%20Long%20Beach%20Outage.pdf, accessed August 12, 2024

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Part II: Subtransmission Redesign & Rebuild (Subtransmission)

**Rebuttal Topic 3: AG-MN Witness Stephens' claims regarding the Company's
Subtransmission Redesign & Rebuild program**

Q29. What recommendations are made by Witness Stephens in the instant case regarding Subtransmission Redesign and Rebuild projects?

A29. Witness Stephens recommends disallowance on three subtransmission projects- Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3509 - totaling \$28.15 million³¹. Additionally, he recommends that the Subtransmission Redesign and Rebuild projects should not be included in the 2026 and 2027 IRM as proposed by the Company³². Company Witness Foley's rebuttal testimony, page 21, line 18 through page 24, line 23, in the instant case addresses the 2026 and 2027 IRM. In addition, Witness Stephens challenges the overall justification of these projects, stating concerns with the projects' effectiveness and the Company's cost benefit analysis.

Q30. What did Witness Stephens claim with respect to the Company's subtransmission projects?

A30. Witness Stephens makes several claims that are addressed in my rebuttal testimony. These claims are as follows:

- Witness Stephens claims that because subtransmission service interruptions account for a small amount of the Company's total service interruptions, the investments in subtransmission projects are not effective³³. He goes on to

³¹ Stephens DT, p. 37, lines 10 – 13

³² Stephens DT, p. 37, lines 14 – 17

³³ Stephens DT, p. 33, lines 10 – 14

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- 1 add that the subtransmission grid already includes system redundancy and
- 2 the Company's investments in subtransmission projects are not necessary³⁴
- 3 • Witness Stephens also claims that subtransmission projects that result in
- 4 larger conductor and the replacement of wood poles with steel poles only
- 5 marginally improves system resilience. He supports his claim by citing that
- 6 wind and ice were responsible for only 1.3% of subtransmission equipment
- 7 outages from 2019 to 2023³⁵.
- 8 • He also claims that the Company has not identified alternatives for some of
- 9 the proposed subtransmission projects to permit a "bang for the buck"
- 10 comparison³⁶.
- 11 • He claims that the three projects (Tie 4105 Phase 3, Tie 4105 Phase 4, and
- 12 Trunk 3905) for which he recommends disallowance have not been
- 13 previously reviewed and approved by the Commission³⁷.
- 14
- 15 Finally, Witness Stephens again makes the claim that the Company has not
- 16 supported its capital expenditures with benefit-cost analyses (BCA) on the
- 17 Subtransmission Redesign and Rebuild projects. Company Witness Kryscynski's
- 18 rebuttal testimony, Rebuttal Issues 5, 6, and 7, in the instant case discusses the
- 19 Company's approach to BCA, Global Prioritization Model (GPM), and the
- 20 reliability model.
- 21

³⁴ Stephens DT, p. 33, lines 14 – 16

³⁵ Stephens DT, p. 34, lines 10 – 14

³⁶ Stephens DT, p. 36, lines 16 – 19

³⁷ Stephens DT, p. 37, lines 8 – 13

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1 **Q31. Do you agree with Witness Stephens' claim that subtransmission projects are**
2 **not effective because subtransmission service interruptions account for a small**
3 **amount of the Company's total service interruptions?**

4 A31. No. First, Witness Stephens himself notes, "... because the redundancy built-in to
5 subtransmission design is so significant, and customer service interruptions so rare,
6 as to make service interruptions unhelpful in evaluating subtransmission grid
7 reliability³⁸." Secondly, while by design the higher voltage subtransmission system
8 leads to less frequent interruptions or outages than the distribution system, Witness
9 Stephens fails to take into account when an outage does occur, it also leads to a
10 significantly larger impact resulting in a large number of customers out of power,
11 often for an extended amount of time. As described below, it is critical to improve
12 the reliability of the aged subtransmission system to prevent future interruptions
13 with large cascading customer outages and prevent the required deployment of
14 large generators and other portable equipment while time-intensive repairs are
15 completed.

16

17 **Q32. Do you agree with Witness Stephens' assessment of the Subtransmission**
18 **Redesign and Rebuild program regarding redundancy?**

19 A32. No. As discussed on page 46 of my direct testimony, because of its critical role and
20 the greater impact to the downstream distribution system, the design of the
21 subtransmission system, by necessity, needs greater design margins and
22 redundancy to the lines feeding substations of the distribution system, which
23 directly feed customers.

24

³⁸ Stephens DT, p. 33, lines 6 – 8

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1 Redundancy is also required to provide operational flexibility by allowing
2 intentional interruptions (equipment shutdowns) to safely perform proactive
3 maintenance activities and equipment upgrades, without impacting customer
4 service. In several instances, intentional interruptions are limited to a short window
5 of time during a year due to an existing thermal and/or voltage planning criteria
6 violation. These constraints limit the company's ability to serve customers during
7 a single equipment failure and plan for intentional interruptions required for system
8 upgrades and routine maintenance.

9
10 However, Witness Stephens does not consider that the Company must still maintain
11 the subtransmission system to ensure this redundancy during normal and
12 emergency operations. As discussed on page 50 of my direct testimony, the
13 subtransmission system is aging beyond 80 years old in some areas. This coupled
14 with ever-increasing severe weather exposures and storm, as well as increased
15 loading in selected areas have led to loss of available contingency power flow paths,
16 thus reducing redundancy and exacerbates resiliency challenges.

17
18 Additionally, Witness Stephens states "DTE's subtransmission system has likely
19 been in its current condition (with a significant proportion of its circuits in violation
20 of planning criteria) for several decades³⁹." From this, it can be interpreted that
21 Witness Stephens does not believe that the subtransmission system concerns need
22 to be addressed in the near term, and the Company can continue to operate as-is
23 indefinitely without any significant consequences to its customers. The Company
24 disagrees with this assessment. The subtransmission planning criteria violations

³⁹ Stephens DT, p. 36, lines 2 – 4

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1 and reliability concerns need to be addressed now and cannot be pushed off into the
2 future. The fact that a subtransmission line is operating with a planning criteria
3 violation today does not mean that it will continue to operate reliably tomorrow. If
4 these concerns are not resolved, the subtransmission system will continue to lose
5 its ability to maintain the required redundancy for which it is designed to ensure
6 grid reliability.

7

8 Given that subtransmission outages can impact multiple substations that can result
9 in more than 10,000 customers impacted, redundancy in the Subtransmission
10 system is an industry best practice to allow for continued customer service during
11 a single contingency situation.

12

13 **Q33. Was the Subtransmission Redesign and Rebuild program developed to**
14 **address the degrading redundancy issues on the subtransmission system?**

15 A33. Yes. As discussed on page 53 of my direct testimony, the Subtransmission
16 Redesign and Rebuild program was developed to address the identified planning
17 criteria violations and reliability performance concerns on the subtransmission
18 system that are compromising system redundancy and reliability. Detailed analysis
19 of the subtransmission system has determined that approximately one-third of
20 subtransmission circuits violate the Company's established planning criteria.
21 These subtransmission planning criteria is based on engineering principles and
22 violations must be addressed in a timely manner to remediate continual degradation
23 that would lead to outages on the subtransmission system with significantly larger
24 customer impacts as compared to the distribution system.

25

Line
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1 **Q34. How did the Company determine that approximately one-third of its**
2 **subtransmission system has planning criteria violation and what is the overall**
3 **impact?**

4 A34. Through an annual process of updating loading information into industry-standard
5 software, Subtransmission Planning Engineers analyze the condition of the system
6 to determine any existing or potential equipment overloads based on the defined
7 planning criteria and redundancy requirements. Pages 47 through 48 of my direct
8 testimony and Exhibit A-23, Schedule M8 DGP pages 101 - 102 detail this analysis.
9 To summarize, Company subtransmission planning engineers analyze the
10 subtransmission system by modeling multiple electric system scenarios across each
11 individual subtransmission line with all possible contingency situations
12 (unintentional equipment shutdowns) assessed. These analyses are conducted
13 utilizing industry-standard modeling software with individual substation loads
14 submitted by Company SMEs and the models used by the Midcontinent
15 Independent System Operator (MISO).

16
17 The analysis performed revealed that one-third of the circuits on the
18 subtransmission system has a thermal and/or a voltage planning criteria violation.
19 A sample of this data was provided in discovery response U-21534 MNSCDE-
20 5.5a(S1) in the instant case and included in Exhibits A-50, Schedule OO1 and A-
21 50, Schedule OO2.

22
23 The significance of a violation is that a circuit experiencing a thermal and/or voltage
24 planning criteria violation has capacity limitations as additional load can't be added

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1 in a permanent and/or temporary bases without a risk of equipment damage that can
2 result in cascading outages, impacting a significant number of customers.

3

4 **Q35. What is a subtransmission planning criteria thermal violation?**

5 A35. Thermal violations, a subset of planning criteria violations, occur when analysis
6 indicates that subtransmission equipment overloads will likely lead to the
7 overheating of equipment, resulting in permanent damage or failure of the
8 equipment, based on DTE's Subtransmission Planning Criteria and Equipment
9 Thermal Loading Policy. The overloading conditions are a result of general load
10 growth over time.

11

12 For system day-to-day normal operating conditions, the subtransmission equipment
13 can be loaded up to 100% of its normal rating without damaging equipment or
14 causing outages to customers. When loaded above 100%, it's considered a thermal
15 violation. For example, the subtransmission trunk line TRK4217 has a normal
16 rating of 19MVA, yet it currently serves 21.8 MVA of load under normal operating
17 conditions, meaning this cable is loaded to 115% of its normal rating. This day-to-
18 day over capacity condition is leading to the degradation of the cable life.
19 Additionally, when the load peaks above the day-to-day normal rating, such as on
20 a hot summer day, there is a further increase in the probability of failure. The
21 Company has proactively identified and developed projects to address all day-to-
22 day over capacity conditions.

23

24 For emergency conditions, which is when a single contingency event occurs for a
25 limited period of time, the subtransmission equipment can be loaded to 90% of its

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1 emergency rating. When equipment is exceeding 90% of its emergency rating, load
2 shed (or intentional customer outages) must be initiated to protect the equipment
3 from failure due to thermal loading and overheating.

4
5 In a typical case where two subtransmission lines are feeding a distribution
6 substation and one of them is interrupted due to a failure or outage event, the other
7 subtransmission line can only serve load that is up to 90% of its emergency rating
8 on a temporary basis while the first line is being restored. If the combined load of
9 the distribution substation exceeds 90% of the emergency rating of the remaining
10 subtransmission circuit, load will be intentionally interrupted to prevent equipment
11 damage and additional cascading outages.

12

13 **Q36. Can you detail an example where a thermal violation impacted system**
14 **redundancy?**

15 A36. Yes, the Trunk 359 example below demonstrates a thermal violation where the
16 Company had to shed load until mobile equipment was deployed.

17

18 Example: Trunk 359

19 On September 4, 2023, there was a cable failure on Trunk 4338, which serves
20 distribution substation transformer 1. The load normally served from distribution
21 substation transformer 1 was automatically transferred to distribution substation
22 transformer 2, which is served from Trunk 359. Trunk 359 then exceeded its
23 emergency rating while it carried all the load of the distribution substation
24 (transformers 1 and 2). As a result, all the circuits out of the distribution substation
25 were rotated through outages (load shed) by the System Operator, until five large

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1 portable generators delivered and installed to relieve load on September 6th. Final
2 repairs were completed on September 16th, and the circuits were returned to their
3 normal state.

4
5 As shown in Figure 3, this event resulted in over 5,000 customers experiencing over
6 1.5 million customer minutes interrupted for approximately two days. A project
7 has been developed to replace the cable of Trunk 359 to increase the circuit rating
8 and prevent future load shedding for this single contingency event, loss of Trunk
9 4338.

Figure 3 : Distribution Substation Outages from September 4, 2023

Event

Summary of Haskell Load Shed between 9/4/2023 & 9/6/2023 to Mitigate Overload on TRK 359			
Circuit	Total Customers	Outage Duration (minutes)	Total Customer Minutes between 9/4/2023 & 9/6/2023
DC 1	860	382	328,520
DC 2	582	248	144,336
DC 3	1106	210	232,260
DC 4	538	536	288,368
DC 5	610	496	302,560
DC 6	870	280	243,600
DC 7	629	42	26,418
Total Customers Impacted: 5195		Total Customer Minutes Interrupted: 1,566,062	

13
14 This event is just an example of the conditions that exist on the subtransmission
15 system, highlighting that redundancy and planning to mitigate single contingency
16 scenarios is critical, and Subtransmission Redesign and Rebuild projects to support
17 this type of event are not discretionary.

18

19

20

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1 **Q37. What is a subtransmission planning criteria voltage violation?**

2 A37. A voltage violation is another sub-category of planning criteria violations. This
3 occurs when subtransmission system conditions lead to a voltage level that is
4 outside of the +/- 5% of the intended nominal system voltage, as is required by the
5 ANSI C84.1 standard. To satisfactorily serve the Company's customers, a 40 kV
6 subtransmission circuit needs to maintain the system voltage between 38 kV (95%)
7 and 42 kV (105%). If the system voltage falls outside of this required range, the
8 customers' equipment (washer, dryer, refrigerator, water heater, furnace, garage
9 door opener, and lights) will not function properly and may cause damage operating
10 at these levels.

11

12 Thus, when the subtransmission circuit voltage falls outside of this required range,
13 it is a violation of the voltage planning criteria under normal operations. Under
14 emergency contingency conditions, where a subtransmission circuit has to carry
15 additional load, the Company does allow subtransmission circuits to be operated as
16 low as 92% of nominal voltage for a short period of time to prevent outages to
17 customers. The Company's voltage violation criteria under emergency single
18 contingency conditions is 92% to 105% of the nominal voltage.

19

20 Voltage violations commonly occur when loading on the system has increased. This
21 could happen during normal operation, such as when load growth from new homes
22 and businesses move into an area and connect to the electric grid, increasing the
23 local electric demand in the area. The voltage violation could also occur in a
24 contingency state when load has been increased on portions of the system due to

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1 temporary load transfers that occur to keep customers energized in the event of
2 equipment failure.

3

4 **Q38. Can you detail an example where a voltage violation could impact system**
5 **redundancy?**

6 A38. Yes, the Northeast Area Transformer Project example below demonstrates how a
7 voltage violation could impact system redundancy.

8

9 Example – Northeast Area Transformer Project

10 The Northeast Area Transformer is a critical source to serving load for the northeast
11 region of DTE's service territory. If an outage were to occur on the Northeast Area
12 Transformer or its associated 120kV or 40kV equipment, there are 29 Substations
13 affecting approximately 37,000 customers, that will have voltage below 92% of
14 nominal voltage, thus creating the emergency voltage violation condition. DTE
15 would be forced to shed load to protect DTE's and customer's equipment until
16 voltage can be restored to our minimum criteria of 92%.

17

18 To resolve this planning criteria violation, a project is underway to install a second
19 120-40kV transformer at the Northeast Area station to provide redundancy for this
20 critical source.

21

22 **Q39. How does the Subtransmission Redesign and Rebuild program improve**
23 **resiliency in the face of storms, in addition to reliability?**

24 A39. Improved resiliency is an additional benefit of the Subtransmission Redesign and
25 Rebuild program. As the Company implements these projects, it looks for

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1 opportunities to relocate subtransmission circuits from often inaccessible deep and
2 railroad right-of-way (ROW) locations to truck accessible road ROW. In addition
3 to significantly reducing the subtransmission circuit's exposure to tree damage, this
4 greatly improves the line crew's access to the circuit from bucket trucks, leading to
5 reduced cost and timing for tree trimming, maintenance and equipment
6 replacement. When there is an outage event, it will reduce the patrol time allowing
7 for quicker restoration.

8
9 In addition to improving accessibility, the Subtransmission Redesign and Rebuild
10 program rebuilds the identified segments to the Company's latest, more resilient
11 construction standards by using steel poles, stronger conductor, stronger clamp top
12 insulators, and shield wire for improved lightening protection. This allows the
13 newly constructed subtransmission circuits to be more durable and resilient during
14 severe weather events.

15
16 Witness Stephens agrees that larger conductor and steel poles are less susceptible
17 to storm damage⁴⁰. However, he then deemed that this improved resiliency is not
18 necessary since wind and ice comprised just 1.3% of subtransmission outages from
19 2019 to 2023 per his calculations, and shown in Figure 4 below. First, wind and
20 ice are not the only causes of storm damage. Secondly, while it is true that ice
21 historically has not occurred frequently in the Company's territory, when it happens
22 it often results in large, catastrophic storm damage. As an example, there was a
23 once in a 50-year ice event in 2023 that dramatically impacted the Company's
24 system, including subtransmission equipment. As noted in more detail in Company

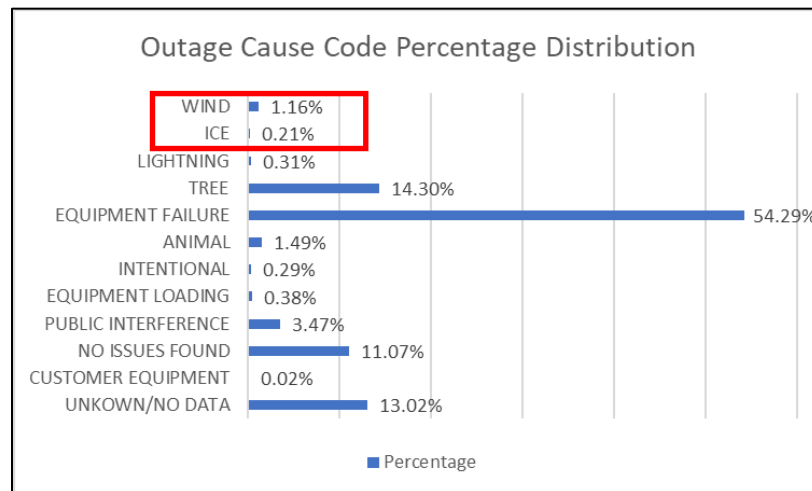
⁴⁰ Stephens DT, p. 34, lines 12 – 13

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1 Witness Kryscynski's direct testimony, page 22, lines 9 – 11, the Company's
2 service territory has been experiencing more frequent and increasing wind speed
3 weather events.

4
5 In his testimony, Witness Stephens does not consider the additional types of outages
6 that can be caused from wind/weather-related damage which can be resolved by
7 rebuilding circuits to the updated standard. Wind/weather-related damage can
8 include broken cross arms and braces, downed conductor, broken poles, and
9 damage from trees. Assuming that approximately 1/4 of equipment failure cause
10 codes are weather related damages and adding wind, ice, lightning, and tree cause
11 codes, Figure 5 below demonstrates that this combination adds up to ~ 30% of
12 subtransmission outages. This shows the need to have a more durable and resilient
13 subtransmission system.

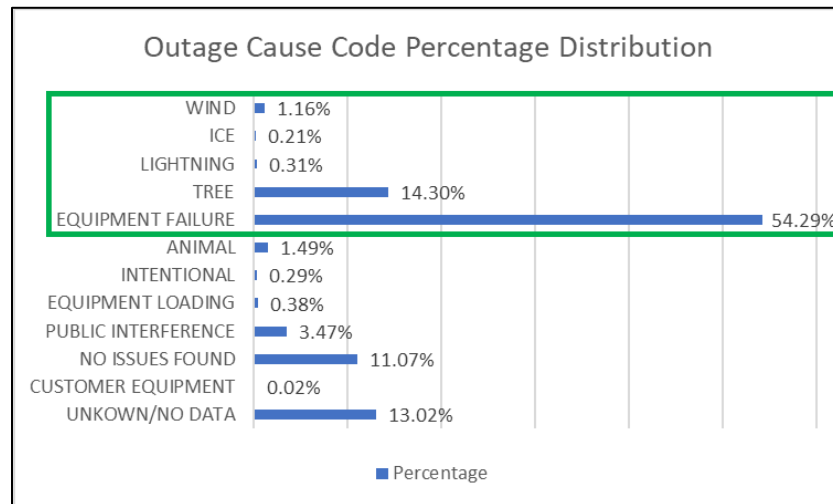
14
15 **Figure 4: Witness Stephens' Cause Code Selection**



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Figure 5: Revised Cause Code Selection



2

3 **Q40. Witness Stephens states “the question is, on which subtransmission circuits**
 4 **are the risks the greatest, and how quickly should they be addressed⁴¹?” How**
 5 **does the Company determine priorities and timing when selecting circuits for**
 6 **Subtransmission Redesign and Rebuild program?**

7 **A40.** As stated in my direct testimony on pages 55 through 56, Company subtransmission
 8 engineers prioritize projects to address the thermal and/or voltage planning criteria
 9 violations based on the violation severity and customer impact. When prioritizing
 10 a subtransmission project for investment, the engineers evaluate the system risks,
 11 including the amount of load over the equipment’s rating in normal day-to-day
 12 configuration, the amount of load loss in a single contingency scenario, the severity
 13 of the voltage violation, the need for future capacity based on confirmed load
 14 projections, and the reliability performance for each circuit, with the resultant
 15 project benefits of mitigating or eliminating these risks. All planning criteria
 16 violations are required to be addressed, and the above methodology determines

⁴¹ Stephens DT, p. 36, lines 4 – 6

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1 which will be resolved first. The prioritized subtransmission project list will be
2 further prioritized against other company investments needs using the GPM model.

3

4 **Q41. Does the Company consider alternatives while developing Subtransmission**
5 **projects?**

6 A41. Yes, it does. The Subtransmission Planning Engineers lead multiple technical
7 reviews during the detailed engineering scope development phase to evaluate project
8 options and determine the most cost-effective solution. These technical reviews
9 include the evaluation of alternatives to the project, with the final scope approval
10 determined by senior level technical planning experts before the project can move
11 to the next phase. Multiple field visits are conducted in early stages of the project
12 with a cross functional team, including those who work on the construction and
13 maintenance of the equipment, to identify potential implementation risks. Project
14 scope alternatives and mitigation plans are developed to address risks, minimize
15 costs and optimize the benefits of the projects.

16

17 **Q42. How do you respond to Witness Stephens' claim that the Company has not**
18 **identified alternatives for some of its proposed subtransmission projects?**

19 A42. In addition to the aforementioned technical review and subsequent field visits
20 which lead to the consideration of project scope alternatives, Company Witness
21 Kryscynski's response to MSNCDE-8.5a in the instant case, included in Exhibit A-
22 50, Schedule OO3, further describes the Company's review of project alternatives.
23 In this response, Witness Kryscynski states:

24

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1 “During initial planning stages of large projects, multiple design options are
2 often explored as different engineering groups collaborate to brainstorm
3 high-level solutions. An initial set of solutions will be narrowed down if
4 some solutions are determined to be unsuitable for reasons such as, but not
5 limited to, the following:

- 6 • Does not adhere to DTE engineering standards and practices
- 7 • Availability or lead time of equipment is too long
- 8 • An extended outage duration is required to complete project
- 9 • Alternative is overly complex and not markedly better than other
10 options”

11

12 **Q43. In addition to the general concerns you’ve noted, does Witness Stephens**
13 **recommend the disallowance of any specific projects that are part of the**
14 **Subtransmission Redesign and Rebuild Program?**

15 A43. Yes. He recommends the disallowance of three specific subtransmission projects:
16 Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3905.

17

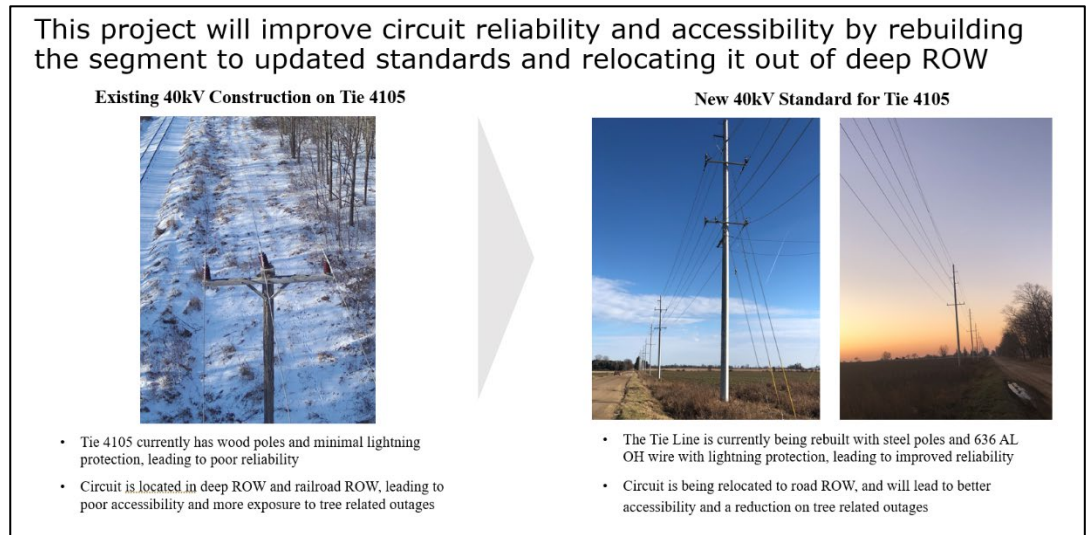
18 **Q44. What is the scope of the Tie 4105 project?**

19 A44. Tie 4105 is a 62-mile circuit serving 7 substations (~ 3,546 customers) in the rural
20 part of the Company’s service territory. To mitigate degrading reliability, the
21 project is to rebuild and relocate approximately 35 miles (~50%) of this circuit. The
22 construction will include equipment designed to the new, more resilient standards,
23 and relocation from deep, heavily treed ROW to more truck accessible road ROW,
24 as shown in Figures 6 and 7 below.

25

1

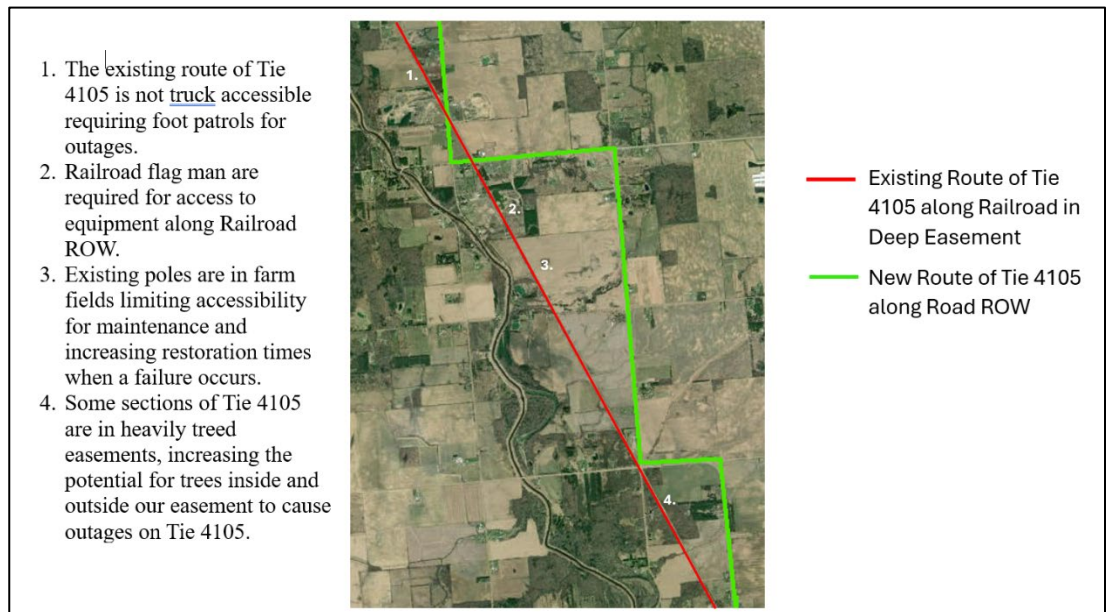
Figure 6 : Tie 4105 Existing Wood Poles vs. New Steel Poles



2

3

Figure 7 : Tie 4105 Existing Route vs. New Route Along Road ROW



4

5 **Q45. Why is it necessary to complete the Tie 4105 project?**

6 A45. As shown in Table 2 below, Tie 4105 reliability performance began to degrade
7 further in 2019. The substations served from Tie 4105 experienced frequent

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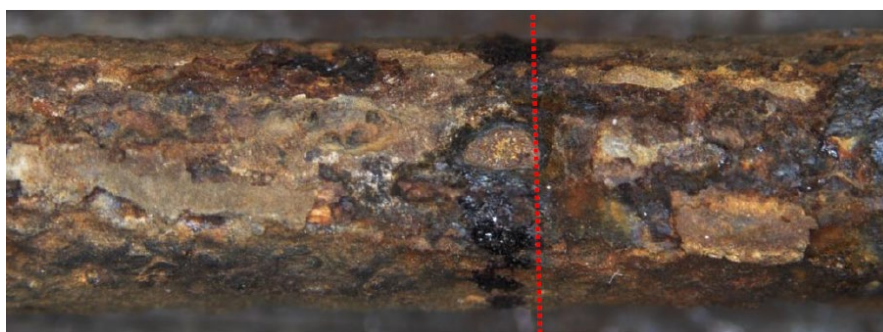
outages. This resulted in escalated complaints by customers and communities to the Company and the Michigan Public Service Commission (MPSC).

Table 2 Tie 4105 Initiative Reliability Performance Improvement

Year	Total Momentary Outages on Tie 4105	Total Sustained Outages on Tie 4105	Total Customer Minutes from TIE4105 Outages	
2015	3	3	4,530,656	
2016	10	3	3,060,346	
2017	9	4	4,671,876	
2018	10	3	1,804,047	
2019	9	7	9,990,554	
2020	1	7	3,798,693	
2021	4	6	7,641,562	
2022	5	7	1,155,311	
2023	2	4	365,832	Tie 4105 Phase 1 Completed

Seventy percent of the poles on Tie 4105 are beyond their life expectancy. Testing of the conductor samples from Tie 4105 demonstrated reduced tensile strength and the steel core zinc layer was no longer present to prevent further oxidation & corrosion, as shown in Figure 8. If not addressed urgently, this will lead to conductor failure and a much-reduced resiliency during severe weather events, as shown in Figure 9.

Figure 8 : Existing Tie 4105 Steel Core of 3/0 ACSR conductor showing corrosion



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2

Figure 9: Existing Tie 4105 3/0 ACSR reduced tensile strength



3

4

Demonstrating the need for greater resiliency, data from the FALLS® lightning database indicates that there were 65 lightning strikes within a half mile of Tie 4105 from January 2016 through December 2018 shown as blue dots on the map in Figure 10 below. Lightning within a half mile is capable of generating induced impulses on power lines. Of these 65 lightning strikes, the data indicates there were 13 lightning strikes during this time interval that were direct strikes to the lines or immediately adjacent to them. See Figure 11 for the date, time, polarity, and intensity of the lightning events.

11

12

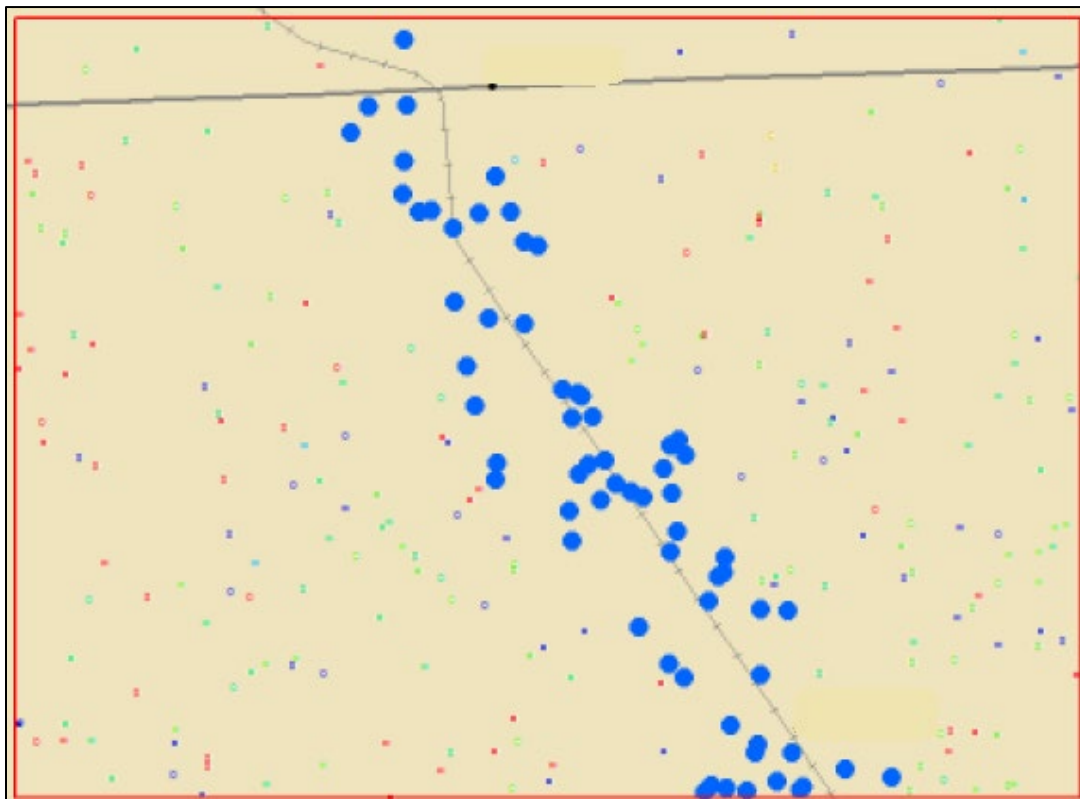
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Figure 10: Lightning strikes within 5-miles of Tie 4105 between

2

2016 and 2018



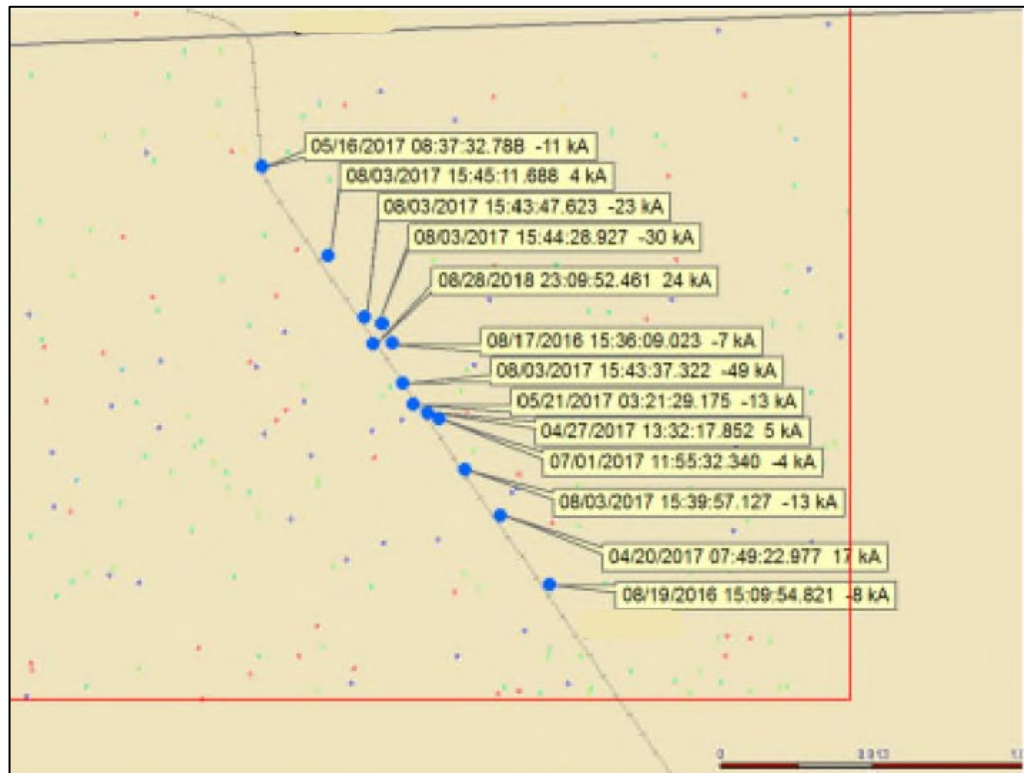
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Figure 11: Lightning activity within a half mile of Tie 4105 between

2

January 2016 and December 2018

3

4

This project is currently underway, and it will be implemented in phases. As shown in Table 1 above, Tie 4105 reliability performance began to show improvements after the first phase of the project was completed in early 2023.

7

8

Q46. What is the scope of the Trunk 3509 project?

9

A46. The Trunk 3509 project's scope is to upgrade about 1.2 miles of exiting underground cable to the current standard higher capacity, more reliable 650 EPR cable. In addition, the circuit connection will be moved to a new station position which involves installing new station equipment (breaker, disconnects, and relay).

12

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1 Trunk 3509 is a 5-mile circuit serving 4 substations (2,539 customers including a
2 major hospital and trauma center). The circuit has a unique configuration where it
3 shares the station position/equipment with another circuit (Trunk 3508). This
4 configuration increases the outage exposure on Trunk 3509 and limits its capacity,
5 as the station equipment must carry the load of two circuits. Additionally, both
6 circuits must be shutdown to perform routine maintenance on station equipment
7 like the breaker.

8

9 **Q47. Why is it necessary to complete the Trunk 3509 project?**

10 A47. Trunk 3509 is experiencing thermal overload planning criteria violations in both
11 normal day-to-day and single contingency scenario. To protect Trunk 3509 from
12 equipment damage during a single contingency scenario, the Company has to
13 implement an emergency load control scheme at one of the substations. If this
14 emergency load control scheme is triggered, all of the customers served from the
15 substation would experience an outage until the failure is fixed or until further
16 operation solutions can be implemented (if available). Also, due to the existing
17 thermal overload planning criteria violation, additional customer load cannot be
18 added to TRK 3509 limiting growth in the area.

19

20 The objective of the Trunk 3509 project is to upgrade the limiting equipment that
21 is causing this thermal overload planning criteria violation. By doing this work, we
22 are alleviating thermal loading violations, and the possibility of shedding customer
23 load during a single contingency event. Additional benefits include increased
24 capacity on Trunk 3509, improving operational flexibility, and reducing outage
25 exposure on Trunk 3509 by giving the circuit its own station position.

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1 **Q48. In addition to the scope and benefits information you provided for the Tie 4105**
2 **and Trunk 3509 projects, does your rebuttal testimony include more**
3 **information on scope, project drivers, costs and benefits for subtransmission**
4 **projects?**

5 A48. Yes. In my testimony above, Q&A 44 to Q&A 47, I have further explained in detail
6 the Tie 4105 and Trunk 3509 projects and why it is necessary to complete them.

7

8 In addition, Exhibit A-23, Schedule M6 provides detailed project drivers, required
9 scope and associated benefits for each Subtransmission Redesign and Rebuild
10 project.

11

12 **Q49. Do you have an additional concern with AG-MN Witness Stephens'**
13 **recommendation on disallowance of subtransmission projects?**

14 A49. Yes. Witness Stephens states on page 37 lines 8-9 of his testimony that "I
15 recommend that the Commission disallow cost recovery on all such projects that
16 the Commission has not already approved. In 2024 and 2025, DTE projects
17 bringing three such projects online, and adds them to rate base in the instant
18 application. The three projects – Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk
19 3509 – total \$28.15 million⁴²." He seems to indicate that the three named projects
20 were not previously approved by the Commission, that is incorrect. These projects
21 were 1) included in case No. U-21297, Exhibit A-12 B5.4, page 9 of 21, line 17
22 (Tie 4105) and line 21 (Trunk 3509), and 2) were in fact approved, not disallowed
23 in the Commission Order⁴³.

⁴² Stephens DT, p. 37, lines 8 – 11

⁴³ MPSC Order in Case No. U-21297, dated December 1, 2023, p. 106. Regarding Subtransmission Redesign & Rebuild (Schedule B5.4, p. 11, line 114 [total of all subtransmission redesign and rebuild

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2

In conclusion, The Company recommends that all the Subtransmission Redesign and Rebuild projects be approved in the instant case and in the IRM including program years 2026 and 2027, as explained in Witness Foley's rebuttal testimony, page 21, line 18 through page 24, line 23.

6

7

Part III: Strategic Undergrounding Program

8

9

Rebuttal Topic 4: AG-MN Witness Stephens' claim regarding the Company's undergrounding projects

10

11

Q50. What recommendations are made by Witness Stephens in the instant case regarding undergrounding projects?

12

13

A50. Witness Stephens recommends the disallowance of the Company's underground pilot program, \$15.6 million in 2024 and \$16.0 million in 2025⁴⁴. Additionally, he stated that undergrounding is expensive and "not the panacea many perceive it to be⁴⁵."

16

17

18

Q51. Why did the Company start an underground pilot project?

19

A51. Per Case No. U-20169, the Company was asked to explore pilot projects to eliminate 4.8kV ungrounded delta rear-lot overhead infrastructure and its associated hazards⁴⁶. With the focus on reducing the safety hazard of a downed

21

projects, including Tie 4105 and Trunk 3509]) states "the Commission finds the ALJ's recommendation to reject the proposed disallowances to be well-reasoned and supported by the record. The Commission adopts the ALJ's findings and conclusions on this issue and approves the 11-month bridge period and test year amounts."

⁴⁴ Stephens DT, p. 43, lines 4 – 11

⁴⁵ Stephens DT, p. 42, line 16

⁴⁶ MPSC Order in Case No. U-20169, dated January 18, 2019, p. 4

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1 conductor of a rear-lot 4.8 kV ungrounded delta circuit, the Company initiated the
2 first pilot on Appoline DC1346 (Appoline).

3

4 **Q52. Why is the Company interested in continuing to underground circuits?**

5 A52. In addition to the safety benefits for the public and Company employees, the
6 Company is interested in undergrounding because: 1) undergrounding improves
7 reliability and resiliency due to the tree impacts to overhead lines caused by
8 increasingly frequent and severe storms and aged overhead infrastructure, 2) over
9 the life cycle of the undergrounding assets, the initial comparatively higher
10 construction costs are balanced by reduced maintenance costs by eliminating the
11 need for tree trimming and pole top maintenance programs, 3) reduction of reactive
12 cost to repair storm damage and increased restoration time, 4) to take advantage of
13 this unique opportunity to be able to underground portions of circuits as it converts
14 its aged 4.8kV, and in some cases gain efficiencies where there is other construction
15 work occurring in the area to improve the system resiliency instead of just the like-
16 for-like replacement of existing overhead infrastructure, 5) other utilities are using
17 undergrounding to harden their system to be more resilient, and 6) customers and
18 communities are reaching out to the Company asking to underground utility lines
19 and eliminate their associated poles. City of Ann Arbor Witness Stults states “Ann
20 Arbor has indicated its interest in having DTE do undergrounding pilots in the
21 City⁴⁷.” Witness Bunch, representing, The Michigan Municipal Association For
22 Utility Issues (MAUI), states that “Many local governments are keenly interested
23 in the undergrounding of electric infrastructure as a reliability measure, the high
24 costs of which might be reduced were projects scheduled to coincide with local

⁴⁷ Stults DT, p. 30, line 20

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1 road, water, sewer and other projects⁴⁸.” Witness Watts, representing Soulardity
2 And We Want Green, Too (DAAO), states “DTE should update our power lines
3 from overhead lines to underground lines to reduce the number of outages⁴⁹.”
4

5 **Q53. Does the Company agree with Witness Stephens’ summarization of the**
6 **Strategic Undergrounding pilot projects?**

7 A53. In part. On a high level, the pilot projects replace rear-lot overhead 4.8kV
8 ungrounded delta infrastructure with underground infrastructure, eliminating the
9 safety hazard associated with a downed conductor. However, Witness Stephens
10 does not include the key point that Appoline and Buffalo-Charles projects are pilots
11 that the Company is using to learn from. This approach allows the Company to
12 develop processes and gain efficiencies on early, smaller projects to reduce
13 implementation cost before larger-scale undergrounding is rolled out as a broader
14 program. These pilot projects also allow the Company to understand potential cost
15 efficiencies that could be achieved by jointly working with municipalities or other
16 utilities. Using this measured approach, the Company can determine when and
17 where this design option can be utilized most effectively.
18

19 **Q54. Does the Company agree with Witness Stephens’ assessment of reliability and**
20 **safety concerns of undergrounding?**

21 A54. No. Witness Stephens states, “underground lines are subject to reliability risk from
22 flooding and careless excavation, and subject to safety risk from both excavation
23 and contact voltage⁵⁰.” Addressing his first concern of flooding as a safety risk,

⁴⁸ Bunch DT, p. 76, lines 19 – 22

⁴⁹ Watts DT, p. 10, lines 13 – 14

⁵⁰ Stephens DT, p. 42, lines 14 – 15

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1 underground cable and equipment are specifically designed to be able to withstand
2 flooding. Currently, approximately 30% of the Company's system is underground.
3 The circuits that are entirely underground have a much better reliability
4 performance than circuits that are overhead. Using 2023 All Weather data,
5 completely undergrounded circuits had a 77% improved SAIFI performance over
6 completely overhead circuits.

7

8 It is true that careless excavation is a risk to reliability and safety. However, this
9 risk is being effectively mitigated. Municipalities require a permit and that all other
10 utilities are marked/identified before digging or starting construction. The
11 Company believes that careless excavation is a very low risk when compared to the
12 safety risk associated with a downed conductor.

13

14 **Q55. Does the Company agree with Witness Stephens' recommendation to disallow**
15 **the full amount for the Strategic Undergrounding Pilot program?**

16 A55. No. The Company believes that undergrounding brings a set of unique benefits to
17 our customers. Undergrounding is an alternative to traditional overhead
18 infrastructure design, one that eliminates the associated safety risk associated with
19 downed conductor and other overhead equipment. Undergrounding provides the
20 benefit of reducing emergent reactive costs and is the most resilient option for
21 severe weather-related events. Due to these benefits of undergrounding, the
22 Company has developed plans to conduct additional pilots, in order to refine its
23 process and continue to focus on reducing implementation costs. The Company
24 recommends that the \$15.6 million in 2024 and \$16.0 million in 2025 for these vital
25 underground pilot projects in the instant case be approved.

26

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1 **Part IV: General Infrastructure Redesign & Modernization Rebuttal Points**

2

3 **Q56. Have any intervenors requested that the MPSC make additional disallowances**
4 **or direct the Company to undertake any specific activities related to**
5 **distribution infrastructure or processes?**

6 A56. Yes, intervenors have suggested a collection of conceptual proposals listed in Table
7 3 below for the Company to undertake. However, as a group these suggested
8 directives are undefined and largely lack the detail requisite to be thoroughly
9 considered. The time, resources, costs, and other inputs necessary to begin these
10 tasks have neither been discussed nor even listed; the resultant values have not been
11 calculated nor considered; alternatives have not been identified nor compared. In
12 an attempt at brevity, the Company is not rebutting all the unsupported and
13 misguided suggestions individually. All of these requested directives should be
14 denied.

15

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Table 3 General Rebuttal Topics

Witness	Rebuttal Point	Rebuttal
ABATE – York	Regarding distribution capital strategic replacements, on page 31, lines 6-11 of Witness York’s direct testimony, she recommends that “the Commission allow only the projected capital expenditures associated with projects that are expected to be in-service during the bridge period and projected test year.”	Company Witness Uzenski’s direct testimony, page 70, lines 19-25 (Q&A 135) states that for capital expenditures on projects that will not be in service during the projected test period do not have a current revenue requirement. Additionally, the Commission found Witness York’s similar proposed adjustments in case No. U-21297 unpersuasive by stating that “the Commission does not find that the question of whether a project will be completed within the test year is dispositive as to whether that project belongs in rate base. ⁵¹ ” The Company recommends the Commission disregard Witness York’s recommendation in the instant case.
MNSC - Woolley	On page 2, line 15 – page 3, line 2 of Witness Woolley’s direct testimony, he provides his principal conclusions on transforming aging that: “- Nominal transformer ratings don’t capture the physics of transformer aging, and they should not be the sole basis for transformer sizing decisions;	The Company offers the following brief rebuttal points to Witness Woolley’s principal conclusions on transformer aging: - Thermal loading and ambient temperatures is only one of several factors including thru-faults and voltage impulses

⁵¹ MPSC Order in Case No. U-21297, dated December 1, 2023, p. 84

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	- The physics of transformer aging lends itself to a more thorough and rigorous analysis that can be done with relatively simple modeling, which I demonstrate; - Transformer aging occurs almost entirely in summer months (June through August), while almost none happens in the winter (December through February); and - Increasing load during winter months is unlikely to compromise the health of existing transformers, which are typically sized to accommodate summer peaks.”	(switching surges, lightning, etc.) that can lead to transformer aging; - The Company uses IEEE standards as the basis for transformer ratings and aging expectations; - The Company acknowledges that a transformer experiences “accelerated” aging in extreme heat due to high load and ambient temperature, but if a transformer were to be fully loaded for 1 year in a cold/winter climate, it would have 1 year worth of life of the transformer consumed as well.
AA – Stults	On page 26, lines 9 – 11 of her testimony, Witness Stults recommends that contributions in aid of construction (CIAC) be no more than it would be if a site were served by a 13.2kV system by arguing that the Company should cover the costs for increasing the capacity in an area by 2.5 times before any CIAC is charged to a developer for increased capacity. She argues that this is because much of the city is served by a 4.8kV system that generally does not have as much capacity as areas served by 13.2kV on page 24, line 23 of her testimony.	In Rebuttal Issue 16 of his rebuttal testimony, Company Witness Hill addresses the CIAC component of Witness Stults’ recommendation. Regarding her claim that 4.8kV systems do not have as much capacity as a 13.2kV system: - It is true that a 4.8kV circuit has less capacity than a 13.2kV circuit. This is why more 4.8kV circuits are needed to serve an area versus a 13.2kV circuit. - Through conversions, a 13.2kV circuit replaces 2 to 3 4.8kV circuits (thus reducing equipment needed). - Adding new load to a circuit is not dependent on voltage, but the existing

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		load on the particular circuit. A loaded 13.2kV circuit will also need additional modifications to serve the new load, just like a 4.8kV circuit.
AA – Stults	On pages 30 – 31 of her testimony, Witness Stults describes the City of Ann Arbor’s interest in partnering with the Company to conduct undergrounding pilots, but states that the Company has not taken advantage of this opportunity to collaborate with the city.	The Company has been engaged with the City of Ann Arbor staff. In October of 2023, the Company worked with Ann Arbor to incorporate an undergrounding project to accommodate a city paving project. Additionally, a Regional Affairs Manager with the Company has established bi-annual meetings with Ann Arbor to review future infrastructure projects within city limits. Individuals included on these meetings include, but is not limited to, Skye Stewart, Andrea Wright, Nicholas Hutchinson, and Nicholas Bayley. A second opportunity to align infrastructure projects has been identified and is pending engineering review for late 2024.

1

2 **Q57. Does this conclude your rebuttal testimony?**

3 A57. 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-21534

REBUTTAL TESTIMONY

OF

MORGAN ELLIOTT ANDAHAZY

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MORGAN ELLIOTT ANDAHAZY

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Morgan Elliott Andahazy (she/her/hers). My business address is One
4 Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate
5 Services, LLC, a subsidiary of DTE Energy Company.

6

7 **Q2. Did you file revised direct testimony in this proceeding on behalf of DTE**
8 **Electric Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of this testimony is to rebut certain positions of Witnesses Alvarez and
14 Stephens on behalf of the Attorney General (AG), Michigan Environmental
15 Council (MEC), and Natural Resources Defense Council (NRDC), collectively
16 referred to as “AG-MN”. The absence of a discussion of other matters in my
17 rebuttal testimony should not be taken as an indication of agreement with other
18 aspects of any intervenor’s testimony.

19

20 **Q4. Are you sponsoring any exhibits in this proceeding?**

21 A4. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-51	PP1	Discovery Response: U-21534 MNSCDE-15.34b
A-51	PP2	NDA Discovery Response: U-21534 MNSCDE-
		15.34b-01 4.8kV Hardening Program Cost per Mile

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1			Analysis
2	A-51	PP3	Discovery Response: U-21534 MNSCDE-15.37
3	A-51	PP4	NDA Discovery Response: U-21534 MNSCDE-
4			15.37-01 PTMM Program Investment per Mile
5			Analysis
6	A-51	PP5	Discovery Response: U-21534 MNSCDE-15.38a
7	A-51	PP6	NDA Discovery Response: U-21534 MNSCDE-
8			15.38a-01 URD Program Investment per Thousand
9			Feet Analysis
10	A-51	PP7	Discovery Response: U-21534 MNSCDE-15.47a
11	A-51	PP8	NDA Discovery Response: U-21534 MNSCDE-
12			15.47a-01 Breaker Program Investment per Breaker
13			Analysis
14	A-51	PP9	Discovery Response: U-21534 MNSCDE-3.6-01
15			4.8kV Hardening Data.xlsx
16	A-51	PP10	NDA Discovery Response: U-21534 MNSCDE-
17			3.10b
18	A-51	PP12	Discovery Response: U-21534 MNSCDE-15.24
19	A-51	PP13	Discovery Response: U-21534 MNSCDE-12.5b
20			Pole Standards
21	A-51	PP14	Discovery Response: U-21534 MNSCDE-12.5c

22

23 **Q5. Were these exhibits prepared by you or under your direction?**

24 A5. Yes, they were.

25

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1 **Q6. How is your testimony organized?**

2 A6. There are twenty specific points I will rebut in my testimony, as listed below. A
3 discussion of why the intervenor's recommendations should not be accepted by the
4 Commission follows.

5

6 Rebuttal Contents

7	Purpose of Testimony	1
8	Strategic Capital Governance	5
9	Rebuttal Issue 1: AG-MN Witness Alvarez's inaccurate claims concerning the	
10	Company's strategic capital program governance.	5
11	4.8kV Hardening Program	7
12	Rebuttal Issue 2: AG-MN Witness Stephens's inaccurate assessment that 4.8kV	
13	Hardening Program wire down benefits are overstated.	7
14	Rebuttal Issue 3: AG-MN Witness Stephens's assertion that 4.8kV Hardening Program	
15	benefits are overstated due to the composition of its control group.	8
16	Rebuttal Issue 4: AG-MN Witness Stephens's inaccurate claim that the 4.8kV	
17	Hardening Program scope is redundant with Tree Trimming and PTMM.	11
18	Table 1 – All-Weather Customer Interruptions Excluding MEDs 3-years avg. before	
19	vs. 3-years avg. after	13
20	Table 2 – Customer Minutes Interrupted Excluding MEDs 3-years avg. before vs. 3-	
21	years avg. after	13
22	Table 3 – Wire Down Events 3-years avg. before vs. 3-years avg. after.....	14
23	Rebuttal Issue 5: AG-MN Witness Stephens's inaccurate claim that DPLD Arc Wire	
24	Removal alone provides nearly all the safety benefits at half the cost of 4.8kV	
25	Hardening Program.	14
26	Table 4 – 4.8kV Technical Conference Benefits	15
27	Rebuttal Issue 6: AG-MN Witness Stephens's assertion that work performed under the	
28	4.8kV Hardening Program are redundant due to later conversions to 13.2kV.	16
29	Rebuttal Issue 7: AG-MN Witness Stephens's incorrect statement that DTE Electric	
30	selected the 4.8kV Hardening Program to increase its capital investment.	18
31	Rebuttal Issue 8: AG-MN Witness Stephens's recommendation that 4.8kV Hardening	
32	should be suspended until a BCA is performed that shows the program benefits exceed	
33	the incremental costs when compared to DPLD Arc Wire Removal.	19
34	Rebuttal Issue 9: AG-MN Witness Stephens's recommended elimination of and	
35	recommended disallowances for the 4.8kV Hardening Program.	20

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1	Table 5 – AG-MN Proposed Disallowances for the 4.8kV Hardening Program.....	21
2	Pole and Pole Top Maintenance and Modernization Program (PTMM).....	23
3	Rebuttal Issue 10: AG-MN Witness Stephens’s statements on PTMM benchmarking.	
4		23
5	Rebuttal Issue 11: AG-MN Witness Stephens’s statements on PTMM standards	
6	changes.....	24
7	Rebuttal Issue 12: AG-MN Witness Stephens’s claim that DTE performed the PTMM	
8	BCA to justify its standards changes.	25
9	Rebuttal Issue 13: AG-MN Witness Stephens’s concerns with the absence of Company	
10	equipment segmented historical failure data in the PTMM BCA Model.	26
11	Rebuttal Issue 14: AG-MN Witness Stephens’s concerns with the value placed on	
12	truck rolls in the Company’s PTMM BCA Model.	27
13	Rebuttal Issue 15: AG-MN Witness Stephens’s concerns that the PTMM BCA	
14	understates customer costs.	29
15	Table 6 – Property Taxes on Capital Investments (Example)	33
16	Rebuttal Issue 16: AG-MN Witness Stephens’s concerns that the PTMM BCA	
17	Whitepaper only refers to 2,242 modeled circuits and it is not clear where benefit-cost	
18	ratios are provided.....	33
19	Rebuttal Issue 17: AG-MN Witness Stephens’s recommendation to order the Company	
20	to perform a new analysis comparing PTM to PTMM.	35
21	Rebuttal Issue 18: AG-MN Witness Stephens’s recommendation to cap PTMM	
22	Program investment levels at \$63.45 million for 2025.....	35
23	Breaker Replacement Program	36
24	Rebuttal Issue 19: AG-MN Witness Stephens’s assessment and recommendation for	
25	the Breaker Replacement Program	36
26	Table 7 – Breaker Replacement Program (2020-2023)	38
27	Table 8 – Breaker Replacement Program Cycle (2020-2023 Average)	39
28	Underground Residential Distribution (URD) Replacement Program	40
29	Rebuttal Issue 20: AG-MN Witness Stephens’s assessment of the URD Replacement	
30	Program.....	40
31	Table 9 – URD Replacement Program (2020-2023)	42
32	Table 10 – URD Replacement Program Cycle (2020-2023)	42
33	General Rebuttal Points	43
34	Table 11 – General Rebuttal Issues	44
35		

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1 **Strategic Capital Governance**

2 Rebuttal Issue 1: AG-MN Witness Alvarez's inaccurate claims concerning the
3 Company's strategic capital program governance.

4 **Q7. Can you summarize your assessment of AG-MN Witness Alvarez's claims**
5 **about the Company's strategic capital program governance?**

6 A7. While not directly stating so, AG-MN Witness Alvarez testimony (pages 27-28)
7 appears to imply that all the referenced strategic capital programs are allocated a
8 budget at the program level with no expectation of how many circuit miles or units
9 of work are expected to be completed. He has also drawn the conclusion that the
10 Company does not track actual circuit miles or units completed by the programs
11 and is therefore unable to support benefit projections.

12

13 **Q8. Do you agree with AG-MN Witness Alvarez's assessment?**

14 A8. No. AG-MN Witness Alvarez's testimony concerning capital governance is more
15 comprehensively rebutted by Company Witness Kryscynski. However, I wish to
16 briefly rebut the specific topic of program work units and explain how they are
17 planned and tracked. I disagree with AG-MN Witness Alvarez's argument that
18 strategic capital programs do not establish targets for circuit miles or units of work
19 to be completed for the annual budgets they are allocated and that the Company
20 cannot therefore track program performance.

21

22 **Q9. Are the Company's programs managed with expectations for how many work**
23 **units they will perform within their budget?**

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1 A9. Yes. The Company's programs are allocated a budget (in dollars) and then based
2 on that level of funding the Company develops a targeted quantity of circuit miles
3 and/or work units to be completed.

4

5 The Company provided budget versus actual capital investment and planned versus
6 actual work units in the following discovery responses:

- 7 • NDA U-21534 MNSCDE-15.34b-01 4.8kV Hardening Program Cost per
8 Mile Analysis¹
- 9 • NDA U-21534 MNSCDE-15.37-01 PTMM Program Investment per Mile
10 Analysis²
- 11 • NDA U-21534 MNSCDE-15.38a-01 URD Program Investment per
12 Thousand Feet Analysis³
- 13 • NDA U-21534 MNSCDE-15.47-01 Breaker Program Investment per
14 Breaker Analysis⁴

15

16 **Q10. Has the Company provided information concerning work units for its**
17 **Infrastructure Resilience and Hardening programs in testimony in this instant**
18 **case?**

19 A10. Yes. I have included units of work in my revised direct testimony for the following
20 programs:

- 21 • 4.8kV Hardening: page 20, table 3 and page 22, table 4
- 22 • PTMM: page 47, table 10 and page 53, table 12
- 23 • Frequent Outage Programs (CEMI): page 80, lines 1-3 and table 13

¹ Exhibit A-51, Schedule PP1 and Exhibit A-51, Schedule PP2

² Exhibit A-51, Schedule PP4

³ Exhibit A-51, Schedule PP5 and Exhibit A-51, Schedule PP6

⁴ Exhibit A-51, Schedule PP7 and Exhibit A-51, Schedule PP8

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- 1 • Cable Replacement: page 92, table 16
- 2 • URD Replacement: page 100, table 21
- 3 • Breaker Replacement: page 105, table 23
- 4 • 40kV Automatic Pole-Top Switch: page 111, lines 11-12
- 5 • Disconnects and Switchers: page 112, lines 18-22
- 6 • Steel Pole Highway Crossings: page 113, lines 16-17
- 7 • Batteries and Chargers: page 114, lines 11-12
- 8 • SCADA Pole-Top Device Replacement: page 115, lines 10-11
- 9 • Substation Regulators: page 116, lines 3-4

10

11 **4.8kV Hardening Program**

12 Rebuttal Issue 2: AG-MN Witness Stephens's inaccurate assessment that 4.8kV
13 Hardening Program wire down benefits are overstated.

14 **Q11. What does AG-MN Witness Stephens say with regards to the Company**
15 **overstating 4.8kV Hardening benefits?**

16 A11. AG-MN Witness Stephens, on page 10, line 20 and page 11, lines 1-9, states, "...
17 while the removal of DPLD wire, which is no longer used and is thus less likely to
18 be maintained, eliminates the risk that an energized *DPLD* wire will fall to the
19 ground, it does NOT eliminate the risk that an energized *DTE* conductor will fall to
20 the ground and not be deenergized, given that the hardening program does not
21 eliminate the fact that there is no neutral wire on the 4.8kV system. In its requests
22 for approval of large amounts of funding for the 4.8kV Hardening program in prior
23 cases, DTE may have created an exaggerated impression of the safety benefits of
24 the 4.8kV Hardening program. It does not appear that DTE discouraged any

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1 exaggerated impression of safety benefit in the Technical Conference workshop
2 DTE hosted on March 22, 2023.”

3

4 **Q12. Has the Company exaggerated wire down reduction or claimed that the 4.8kV**
5 **Hardening Program eliminates all risk of wire downs?**

6 A12. No. While I agree with AG-MN Witness Stephens’s assertion that the 4.8kV
7 Hardening Program eliminates the risk of DPLD arc wire downs, the Company has
8 not claimed that 4.8kV Hardening completely eliminates the risk of wire downs of
9 DTE Electric’s overhead conductor. However, the Company has accurately stated
10 that the improvements made by this program reduces this risk.

11

12 In my revised direct testimony on page 26, in Figure 5, the Company provides
13 analysis that shows a 25% reduction in wire down events on hardened circuits when
14 comparing the three-year average before hardening to the one-year after. This 25%
15 reduction in wire downs is based on actual performance data.

16

17 Rebuttal Issue 3: AG-MN Witness Stephens’s assertion that 4.8kV Hardening
18 Program benefits are overstated due to the composition of its control group.

19 **Q13. What does AG-MN Witness Stephens’s say with regards to the control group**
20 **used to calculate benefits for the 4.8kV Hardening Program?**

21 A13. AG-MN witness Stephens says the following on page 9, lines 1-5 of his testimony,
22 “... the Company appropriately employs a “difference of differences” approach to
23 quantifying reliability improvements from various capital programs using “test”
24 and “control” groups of circuits. But the Company’s control group definition

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1 dramatically exaggerates reliability improvements from capital programs by
2 eliminating tree trimming...”

3

4 **Q14. Do you agree with AG-MN Witness Stephens that the control group**
5 **exaggerates benefits received from the 4.8kV Hardening Program?**

6 A14. No. The intent of this comparison was to show the benefits of 4.8kV Hardening
7 versus a “do-nothing scenario.” This methodology was also used in Case Nos. U-
8 20836 and U-21297 in addition to this instant case.

9

10 For All-Weather SAIDI benefits, Figure 3 on page 24 of my revised direct
11 testimony shows:

- 12 • 38% improvement when comparing three-year average performance before
13 hardening versus one-year after hardening;
- 14 • In a separate chart, it also shows a 23% worsening when comparing three-
15 year average performance before versus one-year after for the control group
16 (4.8kV circuits which have not been hardened or tree trimmed recently).

17

18 The net performance of both hardened and control group circuits is used to derive
19 a total improvement of 61% for hardened circuits on page 25, lines 1-4.

20

21 For SAIDI excluding MEDs benefits: Figure 4 on page 25 of my revised direct
22 testimony shows:

- 23 • 65% improvement in SAIDI excluding MEDs when comparing three-year
24 average performance before hardening versus one-year after hardening;

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- 1 • In a separate chart, it also shows a 3% improvement when comparing three-
- 2 year average performance before versus one-year after for the control group
- 3 (4.8kV circuits which have not been hardened or tree trimmed recently).

4

5 The net performance of both hardened and control group circuits is used to derive

6 a total improvement of 62% for hardened circuits on page 25, lines 7-10.

7

8 For wire down benefits: Figure 5 on page 26 of my revised direct testimony shows:

- 9 • 25% improvement in wire down events when comparing three-year average
- 10 performance before hardening versus one-year after hardening,
- 11 • In a separate chart, it also shows a 22% worsening when comparing three-
- 12 year average performance before versus one-year after for the control group
- 13 (4.8kV circuits which have not been hardened or tree trimmed recently).

14

15 The net performance of both hardened and control group circuits is used to derive

16 a total improvement of 47% for hardened circuits on page 26, lines 3-6.

17

18 The presented data shows that the All-Weather SAIFI, SAIDI excluding MEDs,

19 and wire down event improvements (even when ignoring the control group) from

20 the 4.8kV Hardening Program are significant and show clear and compelling

21 benefits to customers. The Company's presentation of these analyses enables the

22 Commission to make its ruling by either considering hardened circuits before-and-

23 after performance alone or by also considering the control group performance in

24 comparison.

25

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1 Rebuttal Issue 4: AG-MN Witness Stephens's inaccurate claim that the 4.8kV
2 Hardening Program scope is redundant with Tree Trimming and PTMM.

3 **Q15. What does AG-MN Witness Stephens say concerning the redundancy of the**
4 **4.8kV Hardening Program when compared to the PTMM and Tree Trimming**
5 **Programs?**

6 A15. AG-MN Witness Stephens makes two claims implying the 4.8kV Hardening scope
7 is redundant in his testimony:

- 8 • “DTE is required to complete the tree trimming in any event, meaning that
9 the reliability benefits from tree trimming should not be credited to the
10 4.8kV Hardening program.” (page 13, lines 2-4).
11 • “... replacing crossarms when defects are identified is part of the pole top
12 maintenance program in any event.” (page 12, lines 4-5).

13

14 **Q16. Do you agree that the Tree Trim and PTMM Programs make the 4.8kV**
15 **Hardening Program work redundant?**

16 A16. No. The Company disagrees with AG-MN Witness Stephens's implications that the
17 4.8kV Hardening Program is redundant because PTMM and Tree Trimming will
18 be performed on the circuits regardless.

19

20 First, it is important to note that circuits which are within the 4.8kV Hardening
21 Program scope are currently excluded from the scope of the PTMM Program. There
22 is no redundancy between the programs, and hardened circuits will later have
23 PTMM performed on them at an appropriate time in future PTMM cycles.

24

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1 Second, tree trimming is required to allow crews safe and efficient access to
2 equipment. It is not redundant to trim circuits being hardened. The 4.8kV
3 Hardening Program coordinates its work with the Tree Trimming Program and
4 circuits are trimmed before 4.8kV Hardening work begins. Hardened circuits will
5 be later tree trimmed again at an appropriate time in the maintenance tree trimming
6 cycle.

7

8 **Q17. Is there anything else you would like to add for context concerning the 4.8kV**
9 **Hardening Program as compared to the Tree Trimming Program?**

10 A17. Yes. I would also like to state that these programs are complementary in nature and
11 not direct replacements for each other.

12

13 While tree trimming is clearly a beneficial program and is necessary to continue,
14 trimming trees alone does not improve the condition of poles and pole-top
15 equipment. Replacing defective poles and pole-top equipment with newer and
16 stronger designs and materials improves the grid's ability to avoid wire downs and
17 outages from inclement weather and tree impacts. The Company is six years into
18 its Tree Trimming Surge and had 83% of its circuits on-cycle as of year-end 2023.
19 If reliability was only driven by the need for tree trimming as AG-MN Witness
20 Stephens seems to suggest, this is contradicted by the Company experiencing two
21 of its worst storm years in 2021 and 2023.

22

23 The Company presented analysis in discovery response U-21534 MNSCDE-3.6-01
24 4.8kV Hardening Data.xlsx (Exhibit A-51, Schedule PP9) which demonstrates that

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1 the 4.8kV Hardening Program provides significant safety and reliability benefits
 2 three years after work is performed (Tables 1, 2, and 3).

3

4

5

**Table 1 – All-Weather Customer Interruptions Excluding MEDs 3-
 years avg. before vs. 3-years avg. after**

4.8kV Hardening	3-years Avg. Before All-Weather Customer Interruptions	3-years Avg. After All-Weather Customer Interruptions	Difference (Better) / Worse	% (Improvement) / Worsening
Circuits Hardened 2018-2020	124,353	70,123	(54,230)	(44%)
Control Group 2018-2020	692,879	882,197	189,318	27%

6

7

8

**Table 2 – Customer Minutes Interrupted Excluding MEDs 3-years avg.
 before vs. 3-years avg. after**

4.8kV Hardening	3-years Avg. Before Customer Minutes Interrupted Excl. MEDs	3-years Avg. After Customer Minutes Interrupted Excl. MEDs	Difference (Better) / Worse	% (Improvement) / Worsening
Circuits Hardened 2018-2020	16,900,510	5,654,200	(11,246,309)	(67%)
Control Group 2018-2020	114,271,545	94,710,157	19,561,388	17%

9

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Table 3 – Wire Down Events 3-years avg. before vs. 3-years avg. after

4.8kV Hardening	3-years Avg. Before Wire Down Events	3-years Avg. After Wire Down Events	Difference (Better) / Worse	% (Improvement) / Worsening
Circuits Hardened 2018-2020	1,624	1,099	(525)	(32%)
Control Group 2018-2020	9,892	11,307	1,415	14%

2

3 Please note that these 3-year average before and 3-year average after calculated
4 benefits are even higher than the 3-year average before and 1-year after benefits
5 shown in my revised direct testimony. Please also note that this analysis includes
6 the years 2021 and 2023 which were historic storm years when overall system
7 reliability experienced the greatest impacts. Taking all these factors into account, it
8 is clear that some of the Company's most vulnerable customers in and around the
9 city of Detroit have received significant and persistent safety and reliability benefits
10 as a result of the 4.8kV Hardening Program.

11

12 Rebuttal Issue 5: AG-MN Witness Stephens's inaccurate claim that DPLD Arc Wire
13 Removal alone provides nearly all the safety benefits at half the cost of 4.8kV
14 Hardening Program.

15 **Q18. What does AG-MN Witness Stephens assert concerning DPLD Arc Wire**
16 **Removal?**

17 A18. On page 11, lines 12-17, AG-MN Witness Stephens states, "Removing the DPLD
18 wire alone will provide almost all of the safety benefits of the 4.8kV Hardening
19 program at greatly reduced cost, and with a greater deployment speed. The marginal

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1 added safety benefits of the 4.8kV Hardening program over the option to simply
2 remove the DPLD wire are due to two extra steps the 4.8kV Hardening program
3 takes over the “remove DPLD Only” option to reduce the risk that DTE conductor
4 will fall to the ground.”

5
6 **Q19. Do you agree that DPLD Arc Wire Removal alone will provide nearly all of**
7 **the benefits of the 4.8kV Hardening Program at a much lower cost?**

8 A19. No. The March 22, 2023, 4.8kV Technical Conference Presentation (Technical
9 Conference) (Exhibit A-23, Schedule M12, page 39) that Witness Stephens
10 references on page 12 of his testimony states that DPLD Arc Wire Removal would
11 provide approximately 50% as much benefit for approximately 55% as much of the
12 investment required for the 4.8kV Hardening Program (Table 4).

13

14

Table 4 – 4.8kV Technical Conference Benefits⁵

When comparing the alternative approaches, the 4.8kV Hardening program was selected originally because it strikes a balance between cost, reliability, and the timely removal of the arc wire from the DTE Electric system

	Cost per mile ¹	Wire down Reduction	SAIFI Reduction ²	CAIDI Reduction ³	Capacity Increase	Increase DER Usage	Execution Complexity	Potential Use Case
Arc Wire Removal	\$191K	13%	22%	36%	No	No	Low	Lowest overall cost to remove arc wire
4.8kV Hardening	\$353K	26%	44%	72%	No	No	Low	Highest benefit/cost for reliability improvement
Pre-conversion	\$1.7M	90%	85%	85%	No	Yes	Medium	Provides step change in reliability performance
Conversion	\$2.7M	90%	85%	85%	Yes	Yes	High	Best benefit/cost for significant capacity needs
Microgrids	\$14.6M	90%	95%	95%	Yes	Yes	Very High	Potentially application for grid areas with critical reliability needs

DTE

1. Median of cost range
2. SAIFI measures the frequency of customer interruptions
3. CAIDI measures the duration of customer interruptions

39

⁵ Please note that the header saying “CAIDI Reduction” in the 4.8kV Hardening Technical Conference Presentation should have been labeled “SAIDI Reduction”.

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1 **Q20. Do you agree that the only difference between 4.8kV Hardening and DPLD**
2 **Arc Wire Removal is “two extra steps” as alleged by Witness Stephens?**

3 A20. No. If a program was developed to narrowly limit its scope to DPLD arc wire
4 removal, the only poles and pole-tops which would have been inspected and
5 addressed were those which are collocated with DPLD arc wire (approximately half
6 as many circuit miles as under the 4.8kV Hardening Program).

7

8 The 4.8kV Hardening Program scope includes the following differences from the
9 DPLD Arc Removal option:

10 1. More intensive tree trimming (removal of all overhanging vegetation
11 and an additional 10 feet of clearance) and on twice as many circuit
12 miles,

13 2. Pole-top inspection and replacement on twice as many circuit miles,

14 3. Pole inspection and replacement on twice as many circuit miles,

15 4. Removal of abandoned service lines (reduces wire down risk),

16 5. Primary deconductoring in abandoned areas (reduces wire down risk).

17

18 Rebuttal Issue 6: AG-MN Witness Stephens’s assertion that work performed under
19 the 4.8kV Hardening Program are redundant due to later conversions to 13.2kV.

20 **Q21. What does AG-MN Witness Stephens assert with regards to 4.8kV Hardening**
21 **work being made redundant when the circuits are later converted to 13.2kV?**

22 A21. On page 14, lines 6-11, AG-MN Witness Stephens says “... most of the work
23 completed under the 4.8kV Hardening program (other than full tree trimming,
24 which must be completed irrespective of hardening) will be rendered redundant
25 when a 4.8kV circuit that has been hardened is converted to a 13.2kV circuit. DTE

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1 cannot justify the installation of fiberglass crossarms with a service life likely in
2 excess of 50 years on a circuit DTE aims to convert to 13.2kV in the next 15 years
3 or so.”

4

5 **Q22. Does the Company’s plan to convert 4.8kV circuits to 13.2kV invalidate the**
6 **investments being made in 4.8kV Hardening?**

7 A22. No. The 4.8kV Hardening Program coordinates with the 4.8kV Conversion
8 Program to ensure that circuits selected for near-term conversion (five-years) are
9 not hardened and the circuits that were selected for 4.8kV Hardening that are not
10 expected to see significant load growth are therefore unlikely to be prioritized for
11 conversion.

12

13 Per Company Witness Deol’s rebuttal testimony:

- 14 • “The 15-year conversion goal is a directional target and may change in
15 timing and priority as specific grid needs evolve in different geographic
16 areas and circuits.” (Page 7, lines 4-5)
- 17 • “Ultimately, the grid will be rebuilt at a pace required to support customer
18 needs and affordability. The conversion investments in this case are
19 supported by near-term drivers highlighted in my testimony, such as
20 capacity needs, reliability improvements, and addressing aging and end of
21 life infrastructure.” (Page 7, lines 17-21)

22

23 The pole-top equipment utilized by the 4.8kV Hardening Program is equivalent to
24 the equipment used for 13.2kV circuit configurations. The Company’s engineers

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1 will assess how much of the installed equipment can be retained for conversion to
2 13.2kV when these hardened circuits are selected for conversion in the future.
3 The Company believes it is reasonable and prudent to perform necessary work now
4 to improve safety and reliability for some of its most vulnerable customers in and
5 around the city of Detroit.

6

7 Rebuttal Issue 7: AG-MN Witness Stephens's incorrect statement that DTE Electric
8 selected the 4.8kV Hardening Program to increase its capital investment.

9 **Q23. What does AG-MN Witness Stephens say concerning the Company's selection**
10 **of the 4.8kV Hardening Program?**

11 A23. AG-MN Witness Stephens states on page 13, lines 14-15, "It may be because the
12 4.8kV Hardening program grows DTE's rate base at almost twice the cost per mile
13 as the DPLD wire removal only option."

14

15 **Q24. Was the 4.8kV Hardening Program selected over DPLD Arc Wire Removal**
16 **only to increase the Company's capital return?**

17 A24. No. The Company selected the 4.8kV Hardening Program to maximize benefits to
18 customers when considering the fixed costs associated with planning and managing
19 the work as well as mobilizing and demobilizing crews. 4.8kV Hardening Program
20 scope was designed to eliminate DPLD arc wire downs, reduce DTE Electric
21 distribution wire downs, increase reliability for customers, remove abandoned
22 service lines, and perform deconductoring in abandoned areas. Additional scope
23 beyond only removing DPLD arc wire was added to take advantage of the fact that
24 crews would already be mobilized to perform work on the circuits and because
25 customers would receive increased benefits from the added scope.

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Rebuttal Issue 8: AG-MN Witness Stephens's recommendation that 4.8kV

3

Hardening should be suspended until a BCA is performed that shows the program

4

benefits exceed the incremental costs when compared to DPLD Arc Wire Removal.

5

Q25. What does AG-MN Witness Stephens say concerning the need for a BCA to support the 4.8kV Hardening Program?

6

7

A25. AG-MN Witness Stephens says on page 13, lines 15-18, "What is needed is a risk-informed benefit-cost analysis showing that the dollar value of the incremental reliability and safety benefits of the 4.8kV Hardening program over the DPLD wire removal only option exceeds the incremental cost of the 4.8kV Hardening program."

11

12

13

Additionally, on page 13, line 21 and page 14, lines 1-3, "I recommend such an

14

approach be used to complete a benefit-cost analysis before the Commission

15

determines that the 4.8kV Hardening program provides greater safety and

16

reliability benefits per dollar than the option of removing the DPLD wire only."

17

18

Q26. Does the Company agree that a BCA should be performed for the 4.8kV Hardening Program before the Commission determines it is prudent and reasonable?

19

20

21

A26. No. The 4.8kV Hardening Program is a mature program that has been ongoing since 2018 and is scheduled to be completed in 2026. The Company has provided actual performance data in Case Nos. U-20836 and U-21297 and additionally in this instant case (pages 23 through 26, including Figures 3, 4, and 5 of my revised direct testimony and pages 13 through 14 including Tables 1, 2, and 3 of my rebuttal

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1 testimony) which show significant and persistent benefits to customers. Suspending
2 the program now to perform a BCA would cause delays and contradict the
3 Commission's order in Case No. U-21297 dated December 1, 2023 on page 93
4 where it directed the Company to accelerate the program, "... completing this work
5 is crucial to the residents and businesses located in areas that contain abandoned
6 arc wire and the Commission agrees with the Staff that the *removal of the arc wire*
7 *should be going faster* [emphasis added]."

8
9 Rebuttal Issue 9: AG-MN Witness Stephens's recommended elimination of and
10 recommended disallowances for the 4.8kV Hardening Program.

11 **Q27. What changes and disallowances does AG-MN Witness Stephens recommend**
12 **for the 4.8kV Hardening Program?**

13 A27. AG-MN Witness Stephens recommends on page 15, lines 1-8, "I recommend the
14 Commission order the Company to eliminate the 4.8kV Hardening program
15 immediately in favor of the "remove DLPD wire only" option. I also recommend
16 the Commission reduce test year spending to the amount required to complete the
17 same number of miles of DLPD wire removal that it would have hardened with the
18 \$80 million requested for 2024. As DLPD wire removal costs 46% less than 4.8kV
19 Hardening per circuit mile, I recommend the Commission reduce the Company's
20 test year capital spending for DLPD wire removal program to \$43.2 million to
21 reflect shift from Hardening to DLPD wire removal only."

22
23 AG-MN Witness Stephens also recommends on page 14, lines 8-12, "I further
24 recommend the Commission disallow \$73.333 million from the bridge period
25 (2024) as a result of DTE's excess spending above what it requested and above

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what the Commission approved in U-21297, and for the additional reason that DTE has consistently failed to evaluate and support the efficacy of Hardening independent of tree trimming” as summarized in Table 5.

Table 5 – AG-MN Proposed Disallowances for the 4.8kV Hardening Program

4.8kV Hardening Program	2024 (\$ thousands)	2025 (\$ thousands)	Source
DTE’s Requested Capital Investment	\$80,000	\$125,000	Exhibit A-12, Schedule B5.4, page 13, line 12
AG-MN Witness Stephens’s disallowances	(\$73,333)	(\$81,800)	AG-MN Witness Stephens’s testimony page 46
AG-MN Witness Stephens’s Proposed Capital Investment	\$6,667	\$43,200	

Q28. Should the Company receive a disallowance in 2024 for increasing investment in 2023 beyond what was included Case No. U-21297?

A28. No. The Commission in its order dated December 1, 2023, stated the following on page 93, “... completing this work is crucial to the residents and businesses located in areas that contain abandoned arc wire and the Commission agrees with the Staff that the *removal of the arc wire should be going faster* [emphasis added].”

The Company’s acceleration of the 4.8kV Hardening Program is consistent with the Commission’s stated support.

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1 **Q29. Do you have any additional concerns with AG-MN Witness Stephens's**
2 **proposed disallowances for the 4.8kV Hardening Program?**

3 A29. Yes. My first concern is that 4.8kV Hardening Program construction is already
4 underway this year and the program will have completed its 2024 workplan by the
5 time the Commission issues its order for this instant case. It will not be possible to
6 undo this work and the associated investment.

7
8 My second concern is that changing the program to DPLD Arc Wire Removal for
9 2025 would result in lower customer safety and reliability benefits, and would
10 require new work scope packages to be developed, which would delay the removal
11 of DPLD arc wire.

12
13 **Q30. Should the Commission adopt AG-MN Witness Stephens's proposed**
14 **disallowances for the 4.8kV Hardening program?**

15 A30. No. The 4.8kV Hardening Program is a mature program and the Company has
16 demonstrated that this program is reasonable and prudent in Case Nos. U-20162,
17 U-20561, U-20836, and U-21297 and has received Commission support and
18 approval in each of these cases.

19
20 The Company also presented an analysis of alternatives to the 4.8kV Hardening
21 Program in its March 22, 2023 Technical Conference and changes could have been
22 ordered in Case No. U-21297, but instead the Commission reiterated its desire that
23 the Company accelerate and complete the 4.8kV Hardening Program in its order
24 dated December 1, 2023, on page 94, "Finding this work to be imperative, however,
25 the Commission approves the requested bridge period and test year funding and

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1 expects to see results in DTE Electric's next rate case, including an accelerated
2 removal of the arc wire as discussed by the Staff."

3

4 **Pole and Pole Top Maintenance and Modernization Program (PTMM)**

5 Rebuttal Issue 10: AG-MN Witness Stephens's statements on PTMM benchmarking.

6 **Q31. What does AG-MN Witness Stephens say regarding the PTMM**
7 **benchmarking performed?**

8 A31. AG-MN Witness Stephens says on page 25, lines 15-20 and page 26, lines 1-3,
9 "The increase in pole inspection standards appears reasonable, though the move to
10 inspect pole tops (once every five years) more frequently than poles (once every
11 ten years) is not as common as the Company seems to imply. In my experience, it
12 is very common to inspect pole tops at the same frequency as poles, as it reduces
13 inspection costs (because poles and pole tops can be inspected at the same time).
14 While I do not oppose the five-year inspection standard for pole tops, the Company
15 should have undertaken a benefit-cost analysis comparing the increased costs of
16 more frequent inspections to the customer benefits of more frequent inspections
17 (the dollar value to customers of the expected reduction in service interruption
18 frequency) before making the change."

19

20 **Q32. Do you agree with witness Stephens' claim that the Company implied it is**
21 **common for utilities to have different cycles for pole-top and pole inspections?**

22 A32. No. Table 6 on page 33 of my testimony was not intended to be a comprehensive
23 analysis of all utilities, nor to determine how common it is to have different cycles
24 for pole-top and pole inspections. This table covers seven utilities located in the
25 Northeast and Midwest regions. The Company performed this benchmarking to

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1 identify industry best practices. This analysis shows that 10–12-year pole
2 inspection cycles are common and that at least five utilities in nearby states inspect
3 pole-top equipment every 4-5 years.

4

5 Rebuttal Issue 11: AG-MN Witness Stephens’s statements on PTMM standards
6 changes.

7 **Q33. What does AG-MN Witness Stephens say regarding PTMM standards**
8 **changes performed?**

9 A33. AG-MN Witness Stephens says, on page 26, lines 17-23, “In my experience
10 changes to construction standards have historically been preceded by workshops
11 attended by personnel from multiple operating regions and departments. Multiple
12 review rounds of edits to the existing standard are completed as the new standard
13 takes shape. Analyses are completed that estimate the incremental benefits (in
14 dollars) and incremental costs of the change to ensure the change is cost-effective.
15 All this is presented to management for formal review and approval.”

16

17 On page 28, lines 7-10, “The Company failed to provide documentation of such a
18 review or approval despite repeated requests. However, the Company hired an
19 external consultant to complete a cost-benefit analysis after the fact, while DTE
20 was preparing its instant application.”

21

22 **Q34. Did DTE perform internal analyses and cross-functional workshops before**
23 **making changes to inspection and construction standards?**

24 A34. Yes. The Company’s engineers performed analysis, and benchmarking and cross-
25 functional workshops occurred over a large span of time beginning over a decade

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1 ago. While the Company acknowledges that the documentation located and shared
2 for all of these activities during discovery was incomplete, the Company did share
3 documentation demonstrating this work was performed in discovery response U-
4 21534 MNSCE-12.5b (Exhibit A-51, Schedule PP13).

5

6 Please note that page 9 of Exhibit A-51, Schedule PP13 demonstrates that the
7 Company utilizes cross-functional teams when reviewing standards changes.

8

9 Rebuttal Issue 12: AG-MN Witness Stephens's claim that DTE performed the
10 PTMM BCA to justify its standards changes.

11 **Q35. What does AG-MN Witness Stephens say regarding with regards to the**
12 **PTMM BCA being used to justify PTMM standards changes?**

13 A35. AG-MN Witness Stephens states, on page 28, lines 12-13 and page 29, lines 1-4,
14 "DTE solicited a consultant after it decided to increase the pole construction
15 standard, and after hundreds of millions of dollars had already been spent. In my
16 experience, the purpose of completing benefit-cost analyses on spending proposals
17 is to make better decisions regarding those proposals *before* costs are incurred. In
18 this case, a benefit-cost analysis on the PTMM program was completed after the
19 fact in an apparent attempt to retroactively justify the change in standards which
20 DTE had already made."

21

22 **Q36. Do you agree that the Company performed a BCA to retroactively justify its**
23 **standards changes?**

24 A36. No. The changes made to standards were informed by benchmarking and industry
25 research (please see pages 32 through 34 of my revised direct testimony for a

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1 summary of benchmarking performed). Some of this work included the Company's
2 participation in a three-year research program with the Electric Power Research
3 Institute (EPRI) which culminated in a Distribution Grid Resiliency report⁶ (Exhibit
4 A-51, Schedule PP14). The decision to perform a BCA was made in 2023 after
5 reviewing feedback the Company received from its rate case. The BCA was not
6 performed to justify the Company's standard changes but to demonstrate that the
7 PTMM Program is beneficial to customers.

8
9 Rebuttal Issue 13: AG-MN Witness Stephens's concerns with the absence of
10 Company equipment segmented historical failure data in the PTMM BCA Model.

11 **Q37. What does AG-MN Witness Stephens say regarding the absence of equipment**
12 **segmented historical failure data within the PTMM BCA Model?**

13 A37. AG-MN Witness Stephens states on page 29, lines 6-13, "For example, the
14 Company cannot provide the historical failure rates for crossarms, porcelain
15 cutouts, and porcelain insulators, nor can it identify service interruptions, customer
16 counts, or average durations associated with failures from these equipment types.
17 Clearly, when projecting improvements relative to existing construction standards,
18 an understanding of the baseline service interruption risk is critical to have. Not
19 only does the consultant's PTMM benefit cost analysis fail to employ these values,
20 DTE does not maintain the data required to produce these values."

21
22 **Q38. Do you agree with the claim by AG-MN Witness Stephens that the PTMM**
23 **BCA rests on a "weak foundation" because the Company does not have precise**

⁶ <https://eprijournal.com/making-distribution-grids-stronger-more-resilient/>

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1 **data on the quantity of customer outages resulting from specific types of pole-**
2 **top equipment failures?**

3 A38. No. 1898 & Co. has assisted nineteen other utilities with similar projects and their
4 analysis has been used to support multi-billion-dollar investments in nine states:
5 Maryland, Illinois, Louisiana, Florida, Texas, Ohio, Indiana, Oklahoma, and
6 Missouri. They maintain a proprietary database of asset failure curves which were
7 reviewed and approved by the Company's engineering subject matter experts and
8 were applied to DTE Electric's actual asset age profiles.

9
10 Rebuttal Issue 14: AG-MN Witness Stephens's concerns with the value placed on
11 truck rolls in the Company's PTMM BCA Model.

12 **Q39. What concerns does AG-MN Witness Stephens express regarding the value**
13 **placed on truck rolls in the Company's PTMM BCA Model?**

14 A39. AG-MN Witness Stephens states on page 29, lines 14-17 and page 30, lines 1-7,
15 "... the PTMM benefit cost analysis overestimates the benefits from avoided costs
16 by assuming that every truck roll avoided (for example, to respond to a pole top
17 equipment failure or a related service interruption) reduces DTE's costs by \$2,000.
18 This appears to be a fully-loaded cost, typically estimated by dividing annual field
19 crew costs, related service center costs (such as the cost of supervisors), vehicle
20 costs, and all allocated corporate general and administrative costs (such as from
21 human resources, accounting, and regulatory services departments) by a count of
22 truck rolls completed in a year. Many if not most of these costs are fixed. What is
23 needed for this estimate is the marginal cost avoided by a truck roll, which is
24 typically gasoline (for the truck) and perhaps some overtime costs. There is no

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1 chance whatsoever that the average marginal cost avoided by a truck roll is anything
2 remotely close to \$2,000.”

3

4 **Q40. Do you agree with AG-MN Witness Stephens’s assertions that the PTMM**
5 **BCA model overstates the cost of truck rolls?**

6 A40. No. AG-MN Witness Stephens argues that only gasoline and overtime should be
7 included for truck rolls in the PTMM BCA as all other costs are fixed and fully
8 loaded. This argument is flawed because it ignores the opportunity costs associated
9 with the inefficiency of dispatching field personnel to address customer outages
10 and wire downs due to emergent pole and pole-top equipment failures, rather than
11 performing programmatic capital improvements where work is performed on the
12 entire circuit and thus a more efficient use of field personnel time.

13

14 It is important to note that the total calculated benefits derived within the PTMM
15 BCA Model from emergent reactive reductions across all circuits is \$1,734,845,577
16 whereas the total calculated benefits from customer outage reductions is
17 \$8,240,507,074 for the years 2024-2063. This means that 17% of the total modeled
18 benefits come from emergent reactive event reductions. It is also important to
19 further note that truck rolls are the smallest portion of modeled emergent reactive
20 reductions.

21

22 Emergent reactive reductions modeled values are:

- 23 • Pole Replacements: \$15,000
- 24 • Pole-top Replacements: \$8,500
- 25 • Truck Rolls: \$2,000

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The Company tested the sensitivity of truck roll cost assumptions and their impact on the PTMM benefit-cost ratios. The system-wide (all circuits) average benefit-cost ratios (BCR) calculated with three different values of truck roll estimates tested are shown below:

6

7

- \$2,000 truck roll assumption: 3.76 BCR

8

- \$350 truck roll assumption: 3.71 BCR

9

- \$0 truck roll assumption: 3.70 BCR

10

11

These results show that the PTMM BCA Model is not sensitive to the value placed on truck rolls (e.g., whether they be set to \$0, \$350, or \$2,000).

13

14

Rebuttal Issue 15: AG-MN Witness Stephens's concerns that the PTMM BCA understates customer costs.

15

16

Q41. What concerns does AG-MN Witness Stephens express that customer costs may be understated in the PTMM BCA?

17

18

A41. AG-Witness Stephens states on page 30, lines 8-17, "... the PTMM BCA also understates customer costs. The costs in the model represent the present value of the costs the Company must pay. It does not include the costs customers must pay on top of DTE capital costs, including DTE's interest expense, a rate of return for shareholders, property taxes DTE must pay to local governments, or state and federal income taxes on the profits DTE earns on PTMM capital spending. Between overstated benefits and understated costs, the Company's representation that the

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1 upgraded poletop construction standards, or the PTMM program based on those
2 standards, deliver benefits in excess of costs rests on a weak foundation.”

3

4 **Q42. Do you agree with AG-MN Witness Stephens that the PTMM BCA Model is**
5 **faulty because it does not account for interest expense, return to shareholders,**
6 **and income taxes?**

7 A42. No. The PTMM BCA Model uses as a discount rate of 6.92%, which is the
8 Company’s pre-tax weighted-average cost of capital. This weighted-average cost
9 of capital incorporates the cost of debt, the cost of equity, and the respective weights
10 of each type of capital (e.g., equity, long-term debt, and deferred taxes). The stream
11 of benefits enabled by the investment is discounted by this 6.92% rate. The benefits
12 are then compared against the capital investment required. To develop an annual
13 revenue requirement model for this required investment, one would apply the pre-
14 tax cost of capital rate (6.92%) against the investment. However, to compare this
15 stream of cash flows against that of the benefits, one would then discount the stream
16 by that same 6.92% rate, effectively resulting in the initial capital investment
17 amount. Therefore, the model’s current methodology is a valid comparison
18 between the two options.

19

20 **Q43. Do you agree with AG-MN Witness Stephens that the PTMM BCA modeled**
21 **results rest on a “weak foundation” because it does not take property taxes**
22 **into account?**

23 A43. No. While it is true that there are property tax implications for replacing poles and
24 pole-top equipment within the PTMM Program, the same is true for poles and pole-
25 top equipment replaced upon failure (Capital Emergent Replacements Storm and

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1 Non-Storm). All equipment replacements the Company performs has an impact on
2 property taxes wherein the taxable value of assets previously installed is removed
3 from the tax base and the value of the new assets installed is added to the tax base
4 and used to calculate property taxes going forward.

5
6 Precisely modeling the property tax implications requires extremely specific
7 assumptions which consider 1) the value, quantity, and timing of assets that are
8 being replaced and thus no longer subject to property tax, 2) the value, quantity,
9 and timing of assets being installed and thus subject to property tax going forward,
10 and 3) a comparison of the changes between 1 and 2 which demonstrate the
11 incremental property tax incurred for any given year.

12
13 In evaluating the model's sensitivity to property tax impacts, it is helpful to consider
14 that the PTMM BCA Model (Exhibit A-51, Schedule PP10) spans 2024-2063 and
15 its calculated outputs ("Summary" tab columns D, H, and I) are as follows:

- 16
- 17 • Total PTMM Investment Required (if all circuits were completed):
18 \$2,617,033,948
 - 19 • Total Emergent Reactive Benefit (capital replacements avoided during
20 Storm and Non-Storm by performing PTMM): \$1,734,845,477
 - 21 • Total Customer Outage Avoidance Benefit (values derived from LBNL ICE
22 Calculator methodology): \$8,240,507,074

23
24 If the Company did not perform PTMM, it would still incur incremental property
25 taxes associated with the difference between the \$1,734,845,477 in Emergent

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1 Reactive capital replacements minus the taxable value of the assets that were
2 replaced and therefore removed from tax base. Performing PTMM on all circuits
3 would require an investment of \$2,617,033,948 and the Company would incur
4 additional property taxes associated with this value minus the taxable value of the
5 assets that were replaced and therefore removed from tax base. Please note that the
6 modeled customer benefits are orders of magnitude higher than both the
7 expenditures required for Emergent Replacements and those required to perform
8 PTMM.

9

10 While there is an incremental property tax associated with performing PTMM, it is
11 not as large as AG-MN Witness Stephens seems to imply, and is only applicable to
12 the PTMM investment that is above the amount that would be incurred for
13 Emergent Capital Replacements.

14

15 I have provided an example of property tax impacts from the capital replacements
16 in Table 6. Please note that the hypothetical example provided is \$1,000,000 of
17 investment and it results in \$27,000 of taxable value in year one and diminishes to
18 \$14,000 of taxable value in year fifteen where it remains until the asset is retired
19 and replaced. In reality, the Company's incremental property tax burden would be
20 less than these totals, because the taxable value of the assets that were replaced
21 would be removed, and the incremental property tax would be the difference
22 between the new property taxes and the property taxes paid on the assets that were
23 replaced. This example holds true for both PTMM Program work and Emergent
24 Capital Replacements.

25

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1

Table 6 – Property Taxes on Capital Investments (Example)

\$ thousands	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15
Capital Invested	\$ 1,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
STC	0.96	0.93	0.90	0.86	0.82	0.78	0.74	0.70	0.67	0.64	0.61	0.58	0.55	0.52	0.50
True Cash Value	\$ 960	\$ 930	\$ 900	\$ 860	\$ 820	\$ 780	\$ 740	\$ 700	\$ 670	\$ 640	\$ 610	\$ 580	\$ 550	\$ 520	\$ 500
Tax Value Adjustment	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Taxable Value	\$ 480	\$ 465	\$ 450	\$ 430	\$ 410	\$ 390	\$ 370	\$ 350	\$ 335	\$ 320	\$ 305	\$ 290	\$ 275	\$ 260	\$ 250
Property Tax Millage	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00
Property Taxes	\$ 27	\$ 26	\$ 25	\$ 24	\$ 23	\$ 22	\$ 21	\$ 20	\$ 19	\$ 18	\$ 17	\$ 16	\$ 15	\$ 15	\$ 14

2

3 **Q44. Does AG-MN Witness Stephens express similar concerns with the Company's**
4 **Strategic Undergrounding BCA?**

5 A44. No. AG-MN Witness Stephens did not express concerns with the Strategic
6 Underground BCA, which utilized the same consultant and approach, but used the
7 modeled outputs to support his recommendation for disallowance.

8

9 Rebuttal Issue 16: AG-MN Witness Stephens's concerns that the PTMM BCA
10 Whitepaper only refers to 2,242 modeled circuits and it is not clear where benefit-
11 cost ratios are provided.

12 **Q45. What concerns does AG-MN Witness Stephens express with regards to the**
13 **quantity of circuits in the PTMM BCA Model?**

14 A45. AG-MN Witness Stephens states on page 30, lines 19-20 and page 31, lines 1-4,
15 "... the report states that of 2,242 circuits modeled, benefits exceeded costs on 95%
16 of these. However, DTE maintains 3,273 distribution circuits, and the Company's
17 confidential workpaper indicates 2,242 circuits is only about 60% of the
18 Company's total circuits. The report does not indicate what criteria the consultant
19 applied to select a subset of the Company's circuits for its stated conclusion, or why
20 they selected only a portion of circuits to summarize in its whitepaper."

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1

2 **Q46. Does the Company's PTMM BCA Model only include 2,242 circuits?**

3 A46. No. While the PTMM BCA whitepaper does have a reference to 2,242 modeled
4 circuits, the "Summary" tab of the PTMM BCA Model (Exhibit A-51, Schedule
5 PP10) that the Company shared with AG-MN Witness Stephens contains a total of
6 3,844 circuits including subtransmission circuits.

7

8 **Q47. Does the PTMM BCA Model clearly show the benefit-cost ratios for all**
9 **circuits?**

10 A47. Yes. The Company provided the PTMM BCA model in its entirety in discovery
11 response NDA U-21534 MNSCDE-3.10b-01 PTMM BCA Model.xlsm (Exhibit A-
12 51, Schedule PP10).

13

14 All circuits are shown on the "Summary" tab and the benefit-cost ratio is provided
15 for each circuit in column K titled "BCA (Emergent Reactive and Customer Outage
16 Benefit)." The "Summary" tab includes 3,844 circuits in total and 2,360 of these
17 circuits have a benefit-cost ratio at or above one.

18

19 The Company informed MNSC in discovery response U-21534 MNSCDE-15.24
20 (Exhibit A-51, Schedule PP12) that this was the field that demonstrated the benefit-
21 cost ratio for circuits and was used to determine whether a circuit was suitable for
22 selection within the PTMM Program.

23

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1 Rebuttal Issue 17: AG-MN Witness Stephens's recommendation to order the
2 Company to perform a new analysis comparing PTM to PTMM.

3 **Q48. What is AG-MN Witness Stephens's recommendation for additional PTMM**
4 **analysis beyond the PTMM BCA already performed?**

5 A48. AG-MN Stephens says on page 31, lines 13-19, "I recommend the Commission
6 order DTE to present an assessment of the reliability difference between PTM
7 circuits and PTMM circuits using historical data in a way that prevents the
8 comingling of tree trimming benefits, and to calculate the monetary value of the
9 reliability improvements relative to the incremental costs of the new pole top
10 construction and inspection standards. This information is necessary for DTE to
11 support its proposed increasing level of capital spending in the PTMM program."

12

13 **Q49. Do you agree with AG-MN Witness Stephens's recommendation to perform**
14 **additional analysis comparing PTM to PTMM?**

15 A49. No, I do not. The Company has shown that its inspection and construction standard
16 changes are supported by benchmarking and industry research. The Company has
17 also performed a benefit-cost analysis that shows the PTMM program (with new
18 standards) is cost beneficial to customers. There is no need for additional analysis
19 to support the program investments.

20

21 Rebuttal Issue 18: AG-MN Witness Stephens's recommendation to cap PTMM
22 Program investment levels at \$63.45 million for 2025.

23 **Q50. What does AG-MN Witness Stephens propose concerning PTMM Program**
24 **investments in 2025?**

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1 A50. AG-MN Witness Stephens states on page 32, lines 1-5, “Regarding test year
2 spending, DTE has not supported the request to increase spending in the PTMM
3 beyond what was approved in U-21297, which was \$63.45 million. The
4 Commission should cap test year spending accordingly. This will ensure customers
5 will not be deprived of benefits in the event the new construction standards prove
6 to be cost-effective.”

7
8 **Q51. Do you agree with AG-MN Witness Stephens’s assertion that the Company**
9 **has not supported its request to increase PTMM investments?**

10 A51. No. The Company has provided evidence that the inspection and construction
11 standard changes were in-line with benchmarking and industry research performed
12 and has supported investment increases with a benefit-cost analysis model.

13
14 **Q52. Should the Commission adopt AG-MN Witness Stephens’s recommendation**
15 **for capping 2025 PTMM investments at \$63.45 million?**

16 A52. No. The Commission should reject AG-MN Witness Stephens’s recommended cap
17 of PTMM investments.

18

19 **Breaker Replacement Program**

20 Rebuttal Issue 19: AG-MN Witness Stephens’s assessment and recommendation for
21 the Breaker Replacement Program

22 **Q53. What is AG-MN Witness Stephens’s assessment and recommendation**
23 **concerning the Breaker Replacement Program?**

24 A53. AG-MN Witness Stephens states that he found the program did not deliver benefits
25 in excess of its costs to customers in Case No. U-21297, states that the Company

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1 has not performed a benefit-cost analysis (BCA) for the program, and
2 recommended the Commission reject the proposed IRM for 2026 and 2027 on
3 pages 43 through 45 of his testimony.

4

5 **Q54. What was the Commission’s position in Case No. U-21297 regarding the**
6 **Breaker Replacement Program investments?**

7 A54. The Commission stated on page 101 in its order dated December 1, 2023, “The
8 Commission finds that the replacement of obsolete circuit breakers is the type of
9 work, like the removal of arc wire, that is necessary and lends itself to few
10 alternatives. ...The company provided evidence that 60% of breakers in the
11 distribution and subtransmission systems (including substation reclosers) are
12 beyond their life expectancy. DTE Electric provided the criteria used for selecting
13 which breakers to replace and indicated that it plans to replace 35 breakers in 2023
14 and 36 in 2024.”

15

16 Additionally, the Commission approved the inclusion of the Breaker Replacement
17 Program in the Company’s Distribution IRM for the years 2024 and 2025 in Case
18 No. U-21297.

19

20 **Q55. AG-MN Witness Stephens points out that a BCA has not been performed for**
21 **the Breaker Replacement Program, how would you respond?**

22 A55. As described by Company Witness Kryscynski in rebuttal testimony, the Company
23 has performed two BCAs (PTMM and Strategic Undergrounding) and is moving to
24 perform more BCAs as part of its overall strategy to support its investments.

25

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1 It is important to note that some of the prerequisite infrastructure investments (such
2 as breaker, URD cable, and system cable replacement), are so foundational and
3 indispensable for the continuity of electric service and the consequences of failure
4 so great (with large scale prolonged outages and the possibly of extensive system
5 damage beyond the breaker itself), that a run-to-failure approach is simply not
6 acceptable.

7

8 **Q56. Can you put the Breaker Replacement Program in context in terms of its scope**
9 **and relative size?**

10 A56. Yes. The Breaker Replacement Program is targeted at breakers that are obsolete
11 and/or have known issues which can cause failures. The Company has invested, on
12 average, approximately \$14.1 million and replaced approximately 35 breakers per
13 year over the span 2020-2023 (Table 7).

14

15 **Table 7 – Breaker Replacement Program (2020-2023)**

Breaker Replacement Program	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2020-2023 Avg
Capital Invested (\$ thousands)	\$10,931	\$17,635	\$14,415	\$13,590	\$14,143
Breakers Replaced	37	39	34	29	35

16

17 As stated in my testimony on page 101, line 9, the Company has approximately
18 6,000 breakers on its system. This average annual replacement of 35 breakers per

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1 year from 2020-2023 represents 0.6% of the Company's breakers and a 171-year
2 replacement cycle (Table 8) and the combined four-year total of 139 breakers miles
3 is 2.3%⁷ of total breakers.

4

5 **Table 8 – Breaker Replacement Program Cycle (2020-2023 Average)**

Total Breakers	2020-2023 Annual Avg. Breaker Replacements	Annual Avg. % Replaced (35 / 6,000)	Replacement Cycle (6,000 / 35)
6,000	35	0.58%	171 years

6 Please note that the Company's current breaker replacement cycle of 171 years far
7 exceeds expected useful life of breakers (30-40 years) and the Company will need
8 to increase the rate of replacement in the near future.

9

10 **Q57. Should the Commission adopt AG-MN Witness Stephens's disallowance of**
11 **capital investment for the Breaker Replacement program in the 2026 and 2027**
12 **IRM?**

13 A57. No. As I have described above, these investments are reasonable and prudent.
14 Further, the URD Replacement program meets the screening criteria used by the
15 Company to identify investment programs that are good candidates for IRM
16 treatment. Please see Company Witness Foley's testimony for additional rebuttal
17 on this topic.

18

⁷ 2020-2023 total breakers replaced divided by total breakers (139 / 6,000 = 2.3%)

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1 **Underground Residential Distribution (URD) Replacement Program**

2 **Rebuttal Issue 20: AG-MN Witness Stephens's assessment of the URD Replacement**
3 **Program.**

4 **Q58. What is AG-MN Witness Stephens's assessment and recommendation**
5 **concerning the URD Replacement Program?**

6 A58. AG-MN Witness Stephens states that he found the program did not deliver benefits
7 in excess of the costs to customers in Case No. U-21297, states that the Company
8 has not performed a benefit-cost analysis (BCA) for the program, and
9 recommended the Commission reject the proposed IRM for 2026 and 2027 on
10 pages 43 through 45 of his testimony.

11

12 **Q59. What was the Commission's position in Case No. U-21297 regarding the URD**
13 **Replacement Program investments?**

14 A59. The Commission stated on page 99 of its order dated December 1, 2023, "The
15 Commission recognizes that regular maintenance is necessary and that faulty cables
16 should be replaced, and DTE Electric provided evidence that multiple factors are
17 considered in determining where replacements are necessary including vintage,
18 number of failures, and number of affected customers, as well as safety
19 improvements."

20

21 Additionally, the Commission approved the inclusion of the URD Replacement
22 Program in the Company's Distribution IRM for the years 2024 and 2025 in Case
23 No. U-21297.

24

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1 **Q60. AG-MN Witness Stephens points out that a BCA has not been performed for**
2 **the Breaker Replacement Program, how would you respond?**

3 A60. As described by Company Witness Kryscynski in rebuttal testimony, the Company
4 has performed two BCAs (PTMM and Strategic Undergrounding) and is moving to
5 perform more BCAs as part of its overall strategy to support its investments.

6

7 It is important to note that some of the prerequisite infrastructure investments (such
8 as breaker, URD cable, and system cable replacement), are so foundational and
9 indispensable for the continuity of electric service and the consequences of failure
10 so great (with large scale prolonged outages and the possibly of extensive system
11 damage beyond the breaker itself), that a run-to-failure approach is simply not
12 acceptable.

13

14 **Q61. Can you put the URD Replacement Program in context in terms of its scope**
15 **and relative size?**

16 A61. Yes. The URD Replacement Program is targeted at URD feeders that have
17 experienced multiple failures and are known to contain URD cable that is near or
18 beyond expected useful life (40 years). The Company has invested an average of
19 \$6.3 million and replaced an average of 37 miles per year over the span 2020-2023
20 (Table 9).

21

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1

Table 9 – URD Replacement Program (2020-2023)

URD Replacement Program	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2020-2023 Avg
Capital Invested (\$ thousands)	\$964	\$4,705	\$7,043	\$12,411	\$6,281
URD Cable Miles Replaced	3.6	24.5	44.7	75.3	37

2

3 The Company has approximately 10,580 miles of URD cable on its system (Table
4 17 of my revised direct testimony). This average annual replacement of 37 miles
5 per year from 2020-2023 represents 0.35% of the Company's URD cable and a
6 286-year replacement cycle (Table 10) and the combined four-year total of 148.1
7 miles is 1.39%⁸ of total URD cable miles.

8

9

Table 10 – URD Replacement Program Cycle (2020-2023)

Total URD Cable Miles	2020-2023 Annual Avg. URD Cable Miles Replaced	Annual Avg. % Replaced (37 / 10,580)	Replacement Cycle (10,580 / 37)
10,580	37	0.35%	286 years

10

⁸ 2020-2023 total URD cable miles replaced divided by total URD cable miles (148.1 / 10,580 = 1.39%)

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1 Please note that the Company's current URD cable replacement cycle of 286 years
2 far exceeds expected useful life of URD cable (40 years) and the Company will
3 need to increase the rate of replacement in the near future.

4

5 **Q62. Should the Commission adopt AG-MN Witness Stephens's disallowance of**
6 **capital investment for the URD Replacement program in the 2026 and 2027**
7 **IRM?**

8 A62. No. As I have described above these investments are reasonable and prudent.
9 Further, the URD Replacement program meets the screening criteria used by the
10 Company to identify investment programs that are good candidates for IRM
11 treatment. Please see Company Witness Foley's testimony for additional rebuttal
12 on this topic.

13

14 **General Rebuttal Points**

15 **Q63. Have any intervenors requested that the MPSC make additional disallowances**
16 **or direct the Company to undertake any specific activities related to**
17 **distribution infrastructure or processes?**

18 A63. Yes, intervenors have suggested a collection of conceptual proposals listed in Table
19 11 below for the Company to undertake. However, as a group these suggested
20 directives are undefined and largely lack the detail requisite to be thoroughly
21 considered. The time, resources, costs, and other inputs necessary to begin these
22 tasks have neither been discussed nor even listed; the resultant values have not been
23 calculated nor considered; alternatives have not been identified nor compared. In
24 an attempt at brevity, the Company is not rebutting all the unsupported and

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1 misguided suggestions individually. All of these requested directives should be
2 denied.

3 **Table 11 – General Rebuttal Issues**

Witness	Rebuttal Point	Rebuttal
ABATE – York	Regarding distribution capital strategic replacements, on page 31, lines 6-11 of Witness York’s direct testimony, she recommends that “the Commission allow only the projected capital expenditures associated with projects that are expected to be in-service during the bridge period and projected test year. ”	Page 70 of Company Witness Uzenski’s direct testimony, lines 19-25 (Q&A 135) states that for capital expenditures on projects that will not be in service during the projected test period do not have a current revenue requirement. Additionally, the Commission found Witness York’s similar proposed adjustments in case No. U-21297 unpersuasive by stating that “the Commission does not find that the question of whether a project will be completed within the test year is dispositive as to whether that project belongs in rate base.” ⁹ The Company recommends the Commission disregard Witness York’s recommendation in the instant case.

4

5

6 **Q64. Does this conclude your testimony?**

7 A64. Yes.

⁹ Page 84 of Commission Order issued in Case No. U-21297 and dated December 1, 2023

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-21534

REBUTTAL TESTIMONY

OF

KEEGAN O. FARRELL

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF KEEGAN O. FARRELL

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Keegan O. Farrell (he/him/his). My business address is: One Energy
4 Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company as the
5 Manager of Demand Response (DR).

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my testimony is to

- 14 • Respond to testimony of Witness Matthews of the Michigan Public Service
15 Commission (MPSC or Commission) Staff (Staff) on the Company's
16 Commercial and Industrial (C&I) Battery Storage DR Pilot and the
17 proposed disallowance;
- 18 • Respond to testimony of Witness Sherman of The Michigan Energy
19 Innovation Business Council, Institute for Energy Innovation and Advanced
20 Energy United (MEIBC) on the Company's C&I Battery Storage DR Pilot;
- 21 • Respond to testimony of The City of Ann Arbor (AA) Witness Stults
22 regarding the Company's residential generator DR Pilot;
- 23 • Address DR recommendations in the testimony of Witness Richter of the
24 Great Lakes Renewable Energy Association (GLREA);

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- 1 • Address DR recommendations in the testimony of Witness Volkmann
- 2 representing The Ecology Center, Environmental Law & Policy Center,
- 3 Union of Concerned Scientists, and Vote Solar (CEO) and;
- 4 • Respond to testimony of Witness Doherty of the MPSC on the Company's
- 5 SmartCurrent expenditures and address DR recommendations.

6

7 The absence of a discussion of other matters in my testimony should not be
8 regarded as an indication that I agree with all other aspects of the Staff's and
9 intervenor's testimony. The narrow focus of my testimony is instead a
10 consequence of a focus on priority issues in recognition of the available resources.

11

12 **Q4. Are you sponsoring any exhibits in this proceeding?**

13 A4. No, I am not.

14

15 **REBUTTAL TO MPSC STAFF WITNESS MATTHEWS**

16 **Q5. Could you summarize the Company's C&I Battery Storage DR pilot?**

17 A5. Yes. The Company's C&I Battery Storage DR pilot is designed to test the ability
18 to achieve peak demand shaving or shifting during DR events. The pilot will consist
19 of two 250 kW/1 MWh behind-the-meter (BTM) lithium-ion phosphate battery
20 energy storage systems (BESS) at two customer sites. One of the two customers
21 has been identified and the Company is actively working with the customer on the
22 installation and implementation parameters for the BESS.

23

24 **Q6. What recommendation did Staff Witness Matthews' make on the Company's**
25 **C&I Battery Storage DR pilot?**

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1 A6. Witness Matthews (p. 7, lines 7-11) recommends that the Company limit the pilot
2 to a single participant, citing the Company's difficulty in finding a second
3 participant. In addition, Witness Matthews correctly states that the Company is not
4 planning to charge a fee to participating customers and therefore recommends
5 charging a fee to the second participant once the Company has determined the value
6 of the program through testing (lines 16-21).

7
8 **Q7. Why does Witness Matthews make these recommendations?**

9 A7. On page 9, lines 14-20, Witness Matthews states that by charging a fee to the
10 customer, the customer would become more accustomed to a fee and inclined to
11 leverage the battery to recoup its cost. Witness Matthews goes on to say that
12 charging a fee will make the customer more likely to retain the battery after the
13 pilot (lines 16-17) as well as stating that Staff finds it critical to test whether
14 payments for participation would impact the customer's utilization of the battery
15 (lines 18-19).

16
17 **Q8. Does Witness Matthews make any other recommendations about the**
18 **Company's C&I Battery Storage DR Pilot?**

19 A8. Yes. Witness Matthews also recommends the Commission disallow \$2 million for
20 the pilot which includes \$1.4 million in the bridge year and \$0.6 million in the
21 forecasted test year.

22
23 **Q9. How do you respond to Witness Matthews' position that the Company should**
24 **only move forward with one participant?**

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1 A9. While Witness Matthews is correct that a second participant has not yet been
2 determined, the Company is working diligently to find one. By having a second
3 customer with a different load profile and operating characteristics participate in
4 the pilot, the Company can increase its learnings such as comparing battery
5 operations, customer savings, ability to respond to a DR event and the ability to
6 shift and/or reduce load. In addition to these learnings, a second customer will help
7 the Company understand different load shapes to support load forecasting as battery
8 adoption grows. The Company continues to have conversations with interested
9 customers and has worked with its Renewables and Major Account Services Teams
10 to identify and engage potential participants. Only proceeding with one participant
11 at this time would be inappropriate and disengaging to the potential participants
12 who have already been approached by the Company and are either looking for
13 funding opportunities or seeking approval from their executive management to
14 participate. In addition, not yet having a second customer to participate in the pilot
15 is not impacting or delaying the launch of the pilot as the lead time for the ancillary
16 equipment is longer than anticipated. The battery skids will be developed
17 sequentially, and the second skid will be shipped following shipment of the first.
18 Installation for both batteries is not expected to be completed until the H2 of 2025.

19

20 **Q10. Do you agree with Witness Matthews that the Company should charge a fee**
21 **for participation?**

22 A10. No, I do not agree. Witness Matthews states in his direct testimony that the
23 Company is having difficulty finding a second participant yet recommends the
24 Company charge the second participant a fee to participate. This would only further
25 hinder the Company from finding a second participant. Participants have to pay an

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1 estimated \$100,000 to \$150,000 in up-front costs that are associated with the
2 concrete pad and the necessary electrical work. A few of the customers the
3 Company spoke to opted to turn down the Company's offer to participate, citing
4 up-front costs as a reason they choose not to participate. In addition, Witness
5 Matthews provides no evidence that participating customers who pay a fee to
6 participate would leverage the battery more efficiently to recoup the costs. If this
7 argument were to be true, the same could be said for the up-front costs that are
8 incurred by the participating customers.

9

10 **Q11. Should the MPSC disallow \$1.4 million in the bridge period and \$0.6 in the**
11 **forecasted test year associated with the C&I Battery Storage DR Pilot?**

12 A11. No. For the reasons previously discussed, the Company continues to make progress
13 in finding a second participant. In addition, the bridge period spend, and the
14 forecasted test year spend is associated with both batteries and are divided into
15 project milestone payments, not necessarily on a per battery basis. The spend in the
16 bridge period is for procurement of major equipment and implementation costs
17 associated with the pilot inclusive of installation, warranty, and maintenance.

18

19 **REBUTTAL TO MEIBC WITNESS SHERMAN**

20 **Q12. Did MEIBC Witness Sherman recommend any disallowances?**

21 A12. Yes. Beginning with line 11 on page 54 of her direct testimony, Witness Sherman
22 recommends the Commission disallow the costs associated with the C&I Battery
23 Storage Pilot due to not having a second customer identified. Witness Sherman
24 goes on to say that the spend could be approved in the next rate case if a second
25 customer is identified by then.

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1 **Q13. How do you respond to Witness Sherman's recommendations?**

2 A13. The Company appreciates the support from Witness Sherman on future rate case
3 recovery for the C&I Battery. However, for the same reasons as discussed above in
4 Question 11, the costs associated with the C&I Battery Storage pilot should be
5 considered prudent and the Company should receive full recovery.

6

7 **REBUTTAL TO AA WITNESS STULTS**

8 **Q14. Could you summarize the Company's residential home generator pilot?**

9 A14. Yes. The Company's has partnered with Generac Grid Services on the pilot to shift
10 customers' electric load to the customers' generator during peak events. The initial
11 phase of the pilot began in 2023 and the Company successfully enrolled 197
12 customers. Phase two of the pilot is scheduled for later this year which will target
13 enrolling an additional 200 participants. The main objective of the pilot is to
14 determine whether customers would be willing to actively participate and allow for
15 real-time telemetry to control their generators during an event. Pilot participants are
16 incentivized with a \$100 up-front gift card and a \$250 gift card at the end of the
17 pilot term if they stay enrolled for the entire duration.

18

19 **Q15. What position does AA Witness Stults take in regard to the Company's**
20 **residential home generator pilot?**

21 A15. Beginning with line 20 on page 3 of her direct testimony, AA Witness Stults
22 recommends that the Commission disallow all costs associated with residential
23 generator pilot.

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1 **Q16. Why does Witness Stults recommend that the Commission disallow the costs**
2 **associated with the residential home generator pilot?**

3 A16. Witness Stults states that the pilot does not align with the Company's stated climate
4 goals. On page 30, line 5, Witness Stults that "a program that explores the ability
5 to remotely shift a customer's electric load to a gas generator as a demand response
6 solution is simply not in line with the Company's stated climate goals or its claims
7 regarding protecting our planet and planning for our future."

8

9 **Q17. Does Witness Stults provide any alternative proposals to the Company's**
10 **proposed residential home generator pilot?**

11 A17. Yes. Beginning with line 9 on page 30, Witness Stults states the Company could
12 explore a similar pilot using batteries as the power source rather than generators.

13

14 **Q18. How does the Company respond to AA Witness Stults?**

15 A18. Witness Stults appears to misunderstand the purpose of the residential home
16 generator pilot.

17

18 The pilot is targeting customers who already own a whole-home generator. The
19 residential home generator DR pilot is not incentivizing customers to purchase and
20 install a natural gas generator. It is simply targeting customers who already own the
21 technology and incentivizing them to let DTE Electric shift their whole-house load
22 to their generator during DR events. The Company's use of these existing
23 generators during emergency situations lowers the amount of new firm capacity the
24 company requires which allows for additional intermittent renewable resources –
25 helping the Company achieve its clean energy goals. This pilot could become the

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1 framework for a residential battery pilot as the Company continues to understand
2 these types of whole-home resources and their value during DR events.

3

4 **Q19. How does the Company respond to AA Witness Stults's alternative proposal**
5 **to explore a similar pilot using batteries?**

6 A19. Witness Stults alternative proposal around exploring residential batteries has merit
7 as the Company continues to learn about the value of these whole home resources.
8 However, the Company is focused on learning as much as it can from the residential
9 generator pilot before turning its attention to another whole-home pilot. The
10 learnings from the residential home generator pilot may help design the framework
11 for a residential battery DR pilot. Therefore, Witness Stults' proposal to disallow
12 the residential pilot and instead focus on a residential battery pilot should be
13 rejected.

14

15 **REBUTTAL TO GLREA WITNESS RICHTER**

16 **Q20. What recommendations does GLREA Witness Richter make in regard to the**
17 **Company's DR programs?**

18 A20. Beginning on page 35 of his direct testimony, GLREA Witness Richter discusses a
19 critical peak (CP) rebate program and the benefits of such a program. Witness
20 Richter also discusses the benefits of a grid interactive water heater (GIWH) DR
21 program beginning on page 46 of his direct testimony. Ultimately, he recommends
22 the Commission direct the Company in its next rate case or demand response case,
23 to propose a CP-rebate pilot program (p. 46, lines 2-5) and a GIWH pilot program
24 (p. 52, lines 1-4).

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1 **Q21. How do you respond to Witness Richter's DR pilot recommendations?**

2 A21. The Company appreciates the testimony of Witness Richter. Witness Richter
3 discusses the benefits of DR and thoroughly explains his proposed CP-rebate pilot
4 program and GIWH pilot program. The Company will keep these suggestions in
5 mind for potential future pilot opportunities.

6

7 **Q22. Does Witness Richter make any further recommendations beyond the CP-**
8 **rebate pilot program and the GIWH pilot program?**

9 A22. Yes. In addition to recommending the Commission direct the Company to propose
10 these two types of pilot programs, he recommends the Commission create the
11 opportunity for a third-party aggregator to do so if the Company resists.

12

13 **Q23. What are your thoughts on the recommendation for the Commission to create**
14 **an opportunity for third-party aggregators to conduct pilots?**

15 A23. The Company disagrees with the recommendation that the Commission create an
16 opportunity for third-party aggregators to conduct the pilots. In Case No. U-21099,
17 the Commission partially lifted the ban on DR aggregation for bundled electric
18 customers, enacting a size minimum of 1 MW of enrolled load and keeping the ban
19 in place for residential customers. Allowing third-parties to conduct a residential
20 pilot, which would include a CP-rebate pilot and GIWH pilot would be a violation
21 of the U-21099 Order. Furthermore, in the U-21099 Order, the Commission
22 indicated its intention to work with stakeholders to develop appropriate consumer
23 protection policies for resources smaller than 1 MW. Therefore, Witness Richter's
24 recommendation of allowing a third-party to conduct a CP-rebate pilot and GIWH
25 pilot should be rejected.

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1 **REBUTTAL TO CEO WITNESS VOLKMANN**

2 **Q24. How does Witness Volkmann describe a virtual power plant (VPP)?**

3 A24. Beginning on line 1 of page 21 of his direct testimony, Witness Volkmann describes
4 a VPP as “aggregations of customer-owned DER (distributed energy resources)
5 such as rooftop solar and behind-the-meter (“BTM”) batteries, electric vehicles and
6 chargers, electric water heaters, smart buildings and their controls, and flexible
7 commercial and industrial loads that can balance electricity demand and supply and
8 provide utility-scale and localized grid services.”
9

10 **Q25. What is Witness Volkmann’s recommendation regarding VPPs?**

11 A25. On page 25, Witness Volkmann recommends that the Company work with Staff
12 and stakeholders to design a VPP pilot/demonstration for resilience and peak load
13 reduction use-cases using a third-party aggregator, and to include the
14 pilot/demonstration in its 2025 DGP.
15

16 **Q26. How does the Company respond to Witness Volkmann’s recommendation?**

17 A26. The Company appreciates Witness Volkmann’s recommendation and his
18 discussion on VPPs. As noted above, DR aggregation at the residential level is
19 currently banned in the state of Michigan. Currently, the Company offers an array
20 of DR offerings that include such pilots and programs as the residential home
21 generator pilot, Smart Charge pilot, Smart Savers (bring-your-own-thermostat or
22 BYOT), and SmartCurrents among others. The Company works with implementers
23 such as EnergyHub and Weavegrid and looks to further expand these relationships
24 with additional product offerings while also bringing any current and future
25 offerings into a single portfolio. In addition, the Company recently held a

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1 competitive request for proposal to procure 25 MWs of third-party DR as agreed
2 upon in the Company's most recent IRP, Case No. U-21193.

3

4 **REBUTTAL TO MPSC STAFF WITNESS DOHERTY**

5 **Q27. Could you provide background on the Company's SmartCurrents \$1.7 million**
6 **disallowance in 2021?**

7 A27. Yes. As described on page 24, lines 8-14 of my direct testimony, it was agreed upon
8 in the settlement of Case U-21252 (2021 DR Reconciliation) to disallow
9 \$1,672,895 in capital expenses associated with the SmartCurrents Program. The
10 MPSC Staff recommended the disallowance citing that the program was only
11 preapproved for \$3 million in 2021 through Case No. U-20471 (the Company's
12 2019 Integrated Resource Plan (IRP)). The disallowance was the difference
13 between the actual spend on SmartCurrents in 2021 and the approved \$3.3 million
14 (\$3 million plus 10%). In Case U-21242, Staff did not find the overspend to be
15 reasonable because of the lack of value of these costs as demonstrated by the Utility
16 Cost Test (UCT).

17

18 **Q28. What is Witness Doherty's position on the 2021 disallowance in the instant**
19 **case?**

20 A28. Beginning with line 20 on page of his direct testimony, Witness Doherty states that
21 the Staff's recommendation with respect to the disallowed SmartCurrents costs has
22 not changed as the Staff recommended the disallowance due to the spend exceeding
23 what was preapproved in the Company's 2019 IRP. He also states that the Company
24 failed to communicate with Staff that it was exceeding its investment in

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1 SmartCurrents by more than 10% and that the benefits from the increased
2 investment did not exist or unclear.

3

4 **Q29. How does the Company respond to Witness Doherty's recommendation that**
5 **2021 disallowance should remain?**

6 A29. While the Company acknowledges that it overspent what was preapproved in the
7 2019 IRP, the Company requests that \$914,448 be added to the projected test year
8 rate base as the overspend in SmartCurrents was reasonable and prudent. As stated
9 on page 24 of my direct testimony, the overspend was to create a new webpage for
10 the program that enhanced and streamlined the potential and existing customer
11 journey. The new webpage included the additions of allowing for self-service
12 enrollment, unenrollment and management of communication preferences.

13

14 In addition, as further described on page 25 of my direct testimony, a result of the
15 new webpage, the Company has been able to increase enrollments and improve
16 efficiencies in the enrollment process. After the spend increase in 2021, the
17 SmartCurrents program has been cost-effective on a forward looking Levelized
18 Cost of Capacity (LCOC) in 2022 and 2023. This supports the investment the
19 Company made in 2021 to enhance the SmartCurrents program and the
20 expenditures added immense customer value to the program. The \$914,448 of
21 disallowed capital should be considered reasonable and prudent and therefore
22 recoverable.

23

24 **Q30. Did Witness Doherty make any recommendations for the Company's DR**
25 **portfolio?**

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1 A30. Yes. Beginning with line 18 on page 6 of his direct testimony, Witness Doherty
2 recommends expanding the Company's analysis of the cost-effectiveness of its DR
3 programs to include all DR programs as well as interruptible rates. He further
4 recommends that the analysis should be included in its next DR Reconciliation or
5 General Rate Case, whichever happens sooner.

6

7 **Q31. How does the Company respond to Witness Doherty's recommendation?**

8 A31. The Company supports and agrees to expand its cost effectiveness test to include
9 all DR programs, including its DR tariffs. However, the Company believes that any
10 discussion of cost-effectiveness should remain within DR Reconciliation cases only
11 and not be included in rate cases. As the Company issues the results of its cost-
12 effectiveness tests in its annual DR reconciliations today, there is no reason to pull
13 them out of a dedicated DR case and into a much larger and more complex electric
14 rate case filing.

15

16 **Q32. Does this conclude your rebuttal testimony?**

17 A32. 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-21534

REBUTTAL TESTIMONY

OF

MATTHEW A. FIX

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MATTHEW A. FIX

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Matthew A. Fix (he/him/his). My business address is DTE Energy
4 Company, One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE
5 Energy Corporate Services, LLC (DTE LLC), a subsidiary of DTE Energy
6 Company (DTE Energy).

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company (DTE Electric or Company)?**

10 A2. Yes.

11

12 **Purpose of Testimony**

13 **Q3. What is the purpose of your rebuttal testimony?**

14 A3. My testimony will rebut the testimony of several witnesses, including:

- 15 • Attorney General (AG) Witness Coppola's proposal to exclude incentive
16 compensation expense related to 53% of the operating measures and
17 Association of Businesses Advocating Tariff Equity (ABATE) Witness
18 York's proposal to exclude incentive compensation expense related to
19 certain operating measures,
- 20 • Staff Witness Rueckert's proposed adjustment to the Company's projected
21 Employee Savings Plan expense,
- 22 • AG Witness Coppola's proposal to exclude the expense related to the
23 Supplemental Savings Plan, and
- 24 • AG Witness Coppola's proposal to include \$10.1 million of the potential
25 savings arising from the Company's 2024 Voluntary Separation Incentive

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1 Program (VSIP) as a reduction to the Company's total projected Operation
2 and Maintenance (O&M) expense. Also, I will rebut the Citizen Utility
3 Board of Michigan, Michigan Environmental Council and Natural Resource
4 Defense Council, collectively referred to as CUB, Witness Denzler's
5 proposal to include \$34.2 million of estimated gross savings from the VSIP
6 as a reduction to the Company's O&M expense.

7 The absence of a discussion of other matters in my testimony should not be
8 regarded as an indication that I agree with all other aspects of the Staff's and
9 intervenor's testimony. The narrow focus of my testimony is instead a consequence
10 of a focus on priority issues in recognition of the available resources.

11

12 **Q4. Are you sponsoring any exhibits in this proceeding?**

13 A4. Yes. I am sponsoring, in whole or in part, the following exhibits:

14	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
15	A-35	Z1	AIP/REP 2018-2023 Performance Weighted Results
16	A-35	Z2	Employee Savings Plan Expense: Updated Staff
17	A-36	AA5	Benefits Adjustments: Summary

18

19 **Q5. Were these exhibits prepared by you or under your direction?**

20 A5. Yes, they were.

21

22 **Incentive Compensation**

23 **Q6. What is AG Witness Coppola's proposal regarding the Company's incentive**
24 **compensation expense?**

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1 A6. Witness Coppola proposes the exclusion of 52.6% of the Company's projected
2 Annual Incentive Plan (AIP) and Rewarding Employees Plan (REP) expense
3 related to operating measures of \$20.271 million, which results in a disallowance
4 of \$10.663 million (Coppola Direct, page 123, lines 4-9).

5
6 **Q7. What is the basis for Witness Coppola's proposal to exclude 52.6% of the**
7 **incentive compensation expense related to Operating measures?**

8 A7. Witness Coppola relies on his analysis of the operating performance levels achieved
9 for the years 2019 through 2023 to conclude that 47.4% of these measures achieved
10 performance levels of Target or higher for both AIP and REP for all employee
11 groups, as reflected on Exhibit AG-21.

12
13 **Q8. Do you agree with Witness Coppola's analysis of historical operating**
14 **performance measures?**

15 A8. No. Witness Coppola's analysis of the proportion of measures that were at Target
16 or above is flawed because it fails to recognize how AIP and REP are designed.
17 While certain measures may produce results that are less than Target, other
18 measures can produce results that are greater than Target. Moreover, even those
19 measures where actual performance was less than Target can still generate payouts
20 if the actual performance was higher than the Threshold level. Under the AIP,
21 payouts range from 25% for Threshold performance to 175% for Maximum
22 performance for non-executives, and up to 200% for executives, with 100% payouts
23 for Target performance. Payouts under the REP range from 50% for Threshold
24 performance to 150% for Maximum performance, with 100% payouts for Target
25 performance. Thus, if the actual performance is less than Target but higher than

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1 Threshold, payouts under the AIP would range between 25% and 100% and the
2 REP payouts would range between 50% and 100%.

3

4 These ranges in potential payouts result in Witness Coppola's singular focus on
5 whether actual performance was at Target or above or below Target being an
6 inaccurate representation of the impact of performance on actual payouts. For
7 example, in 2019 the Customer Satisfaction Improvement Program that measures
8 the Defects Per Million Opportunities (DPMO) had a Target of 65,645 with actual
9 results of 65,794, which produced a 96.9% AIP payout and a 97.9% REP payout.
10 Had the DPMO actual results in 2019 been only 149 lower the Company would
11 have achieved Target level performance, which represents a variance from Target
12 of only 0.2%. In contrast, Witness Coppola's approach would deem DPMO results
13 of only 0.2% less than Target to result in a zero payout. This is an unreasonable
14 inference and is inconsistent with the design of the plans. Similarly, Witness
15 Coppola's method ignores the impact of performance above Target, which could
16 result in payouts of up to 150% for the REP and up to 200% for the AIP when
17 Maximum performance levels are achieved. Witness Coppola's exclusive reliance
18 on the achievement of performance relative to Target levels fails to recognize the
19 gradients of performance between Threshold and Maximum performance levels
20 that are the basis for actual payouts.

21

22 **Q9. Have you computed the actual operating performance levels for the same**
23 **period that recognizes the gradients of performance between Threshold and**
24 **Maximum levels?**

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1 A9. Yes. Exhibit A-35, Schedule Z1, shows that actual weighted performance for the
2 last five years was 79.3% for the AIP, 81.5% for the AIP Executives, and 69.2%
3 for the REP for a combined average of 76.7%.

4
5 **Q10. Is the use of average annual performance, as reflected on Exhibit A-35,**
6 **Schedule Z1, a more accurate depiction of the Company's historical**
7 **performance than the method used by Witness Coppola on Exhibit AG-49?**

8 A10. Yes. The average annual performance method reflected on Exhibit A-35, Schedule
9 Z1 is a more accurate method of measuring historic performance than the approach
10 used by Witness Coppola. Witness Coppola's approach is based on a simplistic
11 binary model, wherein either Target performance was or was not met. Whereas the
12 methodology reflected on Exhibit A-35, Schedule Z1, recognizes that actual
13 payouts can fall within a wide spectrum of performance levels, consistent with the
14 design of the program.

15

16 **Q11. Is it reasonable to assume that only 47.4% of the operating performance**
17 **measures will be achieved in the projected test year?**

18 A11. No. The establishment of costs to be reflected in the Company's revenue
19 requirement is subject to various uncertainties, but the goal is to establish expenses
20 at the levels that are most likely to be incurred. In this instance, it is reasonable to
21 assume that the Company will, on an overall basis, achieve Target performance
22 levels for both the AIP and REP and include all incentive compensation expense
23 related to the operating measures.

24

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1 **Q12. What is ABATE Witness York’s proposal regarding incentive compensation**
2 **expense related to the Operating measures?**

3 A12. ABATE Witness York proposes that the incentive compensation expense related to
4 the Operating measures that don’t have a measurable net customer benefit, to wit:
5 the Customer Satisfaction and Safety measures, be excluded. Additionally,
6 Witness York proposes the expense related to SAIDI excluding MEDs and CEMI4
7 be excluded due to the “Company’s recent failure to meet its reliability goals, as
8 well as its track record of historic revenue sufficiency amounts”. (York Direct,
9 page 16, lines 8-22 and page 17, lines 1-13).

10

11 **Q13. Do you agree with ABATE Witness York’s proposal regarding the exclusion**
12 **of incentive compensation expense related to the Customer Satisfaction and**
13 **Safety measures?**

14 A13. No. ABATE Witness York’s proposal is flawed for two reasons. First, ABATE
15 Witness York’s proposal seems to rely on the flawed premise that all of the benefits
16 of the individual measures are capable of precise quantification. Second, ABATE
17 Witness York’s proposal represents an unreasonable interpretation and application
18 of the Commission’s standard that incentive compensation expense is only
19 recoverable if the benefits of the incentive compensation plans exceed the related
20 costs. Company Witness Foley addresses why the second rationale is improper.

21

22 **Q14. What is the flaw in ABATE Witness York’s apparent assumption that all the**
23 **individual incentive compensation measures are capable of precise**
24 **quantification?**

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1 A14. The Cost/Benefit analysis reflected on Exhibit A-21 Schedule K6 represents only
2 the reasonably quantified financial benefits of the Company achieving Target
3 performance for each of the measures included in the incentive compensation plans.
4 However, some of the measures provide benefits beyond those able to be precisely
5 quantified. For example, while the quantifiable benefits of the MPSC Customer
6 Complaints measure only amount to \$29,000, which represents the savings from a
7 reduction in time spent by customers and Company employees by the Company
8 achieving Target performance, this doesn't capture the unquantifiable benefits to
9 customers such as the time and frustration leading up to the complaint with the
10 MPSC. Moreover, the benefits also exclude any quantification of the savings
11 realized by the Commission from a reduction in customer complaints. It is clear
12 that the total benefits, both quantified and unquantified, of the Company achieving
13 Target performance in a key customer satisfaction measure would exceed the \$2.3
14 million of expense.
15 Similarly, the benefits of the Company achieving its Net Promoter Score only
16 reflects the benefits of reductions in customer calls and assigns no measurable value
17 to the benefits to customers that may otherwise be inconvenienced by the
18 Company's service levels.
19 In addition, while the quantified benefits of the Company achieving its Target
20 performance for the Safety measures is \$2.585 million, this reflects only the
21 measurable benefits to the Company of improved safety performance and excludes
22 any impact on the communities the Company serves. Further, because it would be
23 callous to assign any value to fatalities, the measure of the benefits specifically
24 excludes the immeasurable benefits of avoided fatalities.

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1 In summary, ABATE Witness York argues that only measurable benefits should be
2 the basis of determining the net customer benefits of the Company achieving its
3 Operating Targets, which is improper because it presumes that all the benefits of
4 the measures are precisely quantifiable, which they are not. The absence of
5 quantification does not imply the benefits are non-existent.

6

7 **Q15. Why is ABATE Witness York's interpretation and application of the**
8 **Commission's incentive compensation Cost/Benefit test requirement**
9 **unreasonable?**

10 A15. The origins of the Commission's policies regarding the recoverability of incentive
11 compensation can be traced back to its Order in Case No. U-10150, wherein the
12 Commission concluded:

13

14 "It further finds that the utility should be placed on notice that
15 future approval of an incentive bonus like this requires a
16 showing that it will not result in excessive costs and the benefits
17 to the utility's ratepayers will be commensurate with those
18 costs." (Order, Case No. U-10150, pages 57-58)

19

20 The Commission has consistently applied the standard articulated in the Order in
21 Case No. U-10150 and assessed the net customer benefits on an aggregate basis
22 without regard to the net benefits for each measure. ABATE Witness York's
23 proposal to only allow recoverability based on each component is unreasonable
24 because it relies only on measurable benefits and is inconsistent with the
25 Commission's traditional practice without any explanation as why a change in
26 practice is either necessary or desirable.

27

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1 **Q16. Is ABATE Witness York's proposal to exclude the incentive compensation**
2 **expense related to SAIDI excluding MEDs and CEMI4 based on recent**
3 **performance appropriate?**

4 A16. No. ABATE Witness York's proposal appears to assume that if the Company does
5 not achieve Target performance levels there will not be any payout under the
6 incentive compensation plans, which is incorrect. As described regarding AG
7 Witness Coppola's proposal, any payouts are based on a range of actual
8 performance between Threshold and Maximum levels. So, while ABATE Witness
9 York observes that the Company's actual 2023 SAIDI excluding MEDs was 157
10 minutes compared to the 2023 Target of 150 minutes, the Company still had
11 payouts under its plans. That is, because the Threshold performance level for
12 SAIDI excluding MEDs was 180 minutes, for AIP the Company paid out 82.5% of
13 Target and for REP the Company paid out 88.3% of Target. ABATE Witness
14 York's singular focus on 2023 results is also misplaced. While the Company's
15 CEMI4 performance level was less than Target in 2023, the Company's 2022
16 CEMI4 performance was above Target. It is unreasonable to rely on one year's
17 performance to assess the probability of the Company achieving its Targets in the
18 projected test year.

19

20 **Employee Savings Plan**

21 **Q17. What adjustment did Staff Witness Rueckert propose to the Company's projected**
22 **Employee Savings Plan expense?**

23 A17. Staff Witness Rueckert used the Company's 2023 Employee Savings Plan (ESP)
24 expense of \$27.286 million and escalated by 4.06% annually based on a five-year
25 average of the annual change in the Company's ESP costs for the years 2018

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1 through 2023 resulting in a projected ESP expense of \$29.547 million (Rueckert
2 Revised Direct, page 7, lines 11-15).

3

4 **Q18. Do you agree with Staff Witness Rueckert's proposed adjustment to the**
5 **Company's projected ESP expense?**

6 A18. No. Staff Witness Rueckert's use of the Company's 2023 ESP expense as a starting
7 point is improper because the Company capitalized an abnormally high proportion
8 of ESP costs in 2023, as explained by Company Witness Uzenski in response to
9 Question 31 of her Rebuttal Testimony.

10

11 **Q19. Have you prepared an alternative analysis of the Company's Employee**
12 **Savings Plan expense?**

13 A19. Yes. Exhibit A-35, Schedule Z2 reflects an update of Staff Exhibit S-15.4 that
14 includes a calculation of the impact of the change in the proportion of the total
15 Employee Savings costs capitalized in 2023. Use of the 2022 percentage of ESP
16 expensed of 60.4% rather than the 2023 percentage of ESP expensed of 54.6%
17 increases the Company's 2023 ESP expense by \$2.901 million (60.4%-54.6% X
18 \$50.018 million).

19

20 **Q20. Did Staff Witness Rueckert use the 2023 percentage of benefits costs expensed**
21 **for all of his projected benefits expense?**

22 A20. No. Staff Witness Rueckert appropriately used the 2022 percentage of Active
23 Healthcare costs expensed of 60.4% in the development of projected Active
24 Healthcare expense, as reflected on Exhibit S-14.3, column (f), line 5.

25

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1 **Q21. What is your adjustment to Staff Witness Rueckert's projected Employee**
2 **Savings Plan expense?**

3 A21. Exhibit A-36, Schedule AA5 reflects the calculation of my adjustment to Staff
4 Witness Rueckert's proposed ESP Plan expense. The adjusted 2023 ESP expense
5 is escalated by the five-year average percentage increase in the Company's ESP
6 costs of 4.06% to develop the ESP expense for 2025 of \$32.688 million, which
7 represents a \$3.141 million increase to Staff Witness Rueckert's ESP projection of
8 \$29.547 million.

9

10 **Supplemental Savings Plan**

11 **Q22. What adjustment did AG Witness Coppola make to the Company's projected**
12 **Supplemental Savings Plan expense?**

13 A22. Witness Coppola proposes the elimination of the expense related to the
14 Supplemental Savings Plan (SSP).

15

16 **Q23. What was the basis for Witness Coppola's elimination of the SSP expenses?**

17 A23. Witness Coppola characterized the costs as being "for a limited number of highly
18 paid employees" and referenced the Commission's elimination of the costs of the
19 Company's Supplemental Employee Retirement Plan (SERP)" (Coppola Direct,
20 page 114, lines 6-9).

21

22 **Q24. What is the SSP?**

23 A24. As I describe in my Direct testimony (page 13, lines 7-19), the SSP is a "make-
24 whole" plan that allows employees whose annual earnings or contributions exceed
25 the limits prescribed by the Internal Revenue Service (IRS) to continue to accrue

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1 benefits that are identical to the benefits they would have accrued in the qualified
2 Employee Savings Plan.

3

4 **Q25. Does the Company offer any non-qualified pension plans?**

5 A25. Yes. The Company offers two non-qualified pension plans. Specifically, the
6 Company provides the Executive Supplemental Retirement Plan (ESRP) and the
7 Supplemental Retirement Plan (SRP). The Commission has consistently excluded
8 the cost of these non-qualified pension plans from the Company's revenue
9 requirements. I presume that AG Witness Coppola's reference to a "SERP" is a
10 reference to these non-qualified pension plans.

11

12 **Q26. Do you agree with Witness Coppola's recommendation?**

13 A26. No. Witness Coppola's proposed exclusion of the SSP expenses is apparently
14 based on his conclusion that it represents a benefit only available to a limited
15 number of highly compensated employees overlooks the fact that the benefits
16 provided through the SSP are exactly the same as those provided within the
17 Company's Qualified Savings Plan.

18

19 **Q27. Has the Commission addressed the issue of the SSP in prior cases?**

20 A27. Yes. The Commission has rejected proposals to disallow the SSP expense in its
21 Orders in Case Nos. U-15244 and U-18255. Specifically, in its Order in Case No.
22 U-18255 the Commission rejected a Staff proposal to disallow the SSP costs based
23 on the Commission's disallowance of non-qualified pension costs in its Order in
24 Case No. U-18014. Instead, the Commission concluded that the precedent of the
25 Order in Case No. U-18255, which allowed recovery of the SSP costs, was more

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1 pertinent than Staff's reliance on the disallowance of non-qualified pensions costs.
2 The circumstances that allowed for a different treatment between the SSP and the
3 non-qualified pension plans in that case have not changed.

4
5 **Q28. What is your recommendation regarding AG Witness Coppola's exclusion of**
6 **the SSP expense?**

7 A28. I recommend the Commission reject AG Witness Coppola's exclusion of \$3.207
8 million of SSP expense because it is a reasonable expense consistent with the
9 Company's qualified ESP and its inclusion in the Company's revenue requirement
10 is consistent with Commission practice.

11

12 **Voluntary Incentive Separation Program (VSIP)**

13 **Q29. What adjustment does AG Witness Coppola propose regarding the Company's**
14 **2024 VSIP?**

15 A29. AG Witness Coppola proposes to reduce the Company's total O&M expense by
16 \$10.1 million, which purports to represent half of the Company's projection of \$20.3
17 million of estimated savings in 2025 (Coppola Direct, page 105, lines 1-9).

18

19 **Q30. Do you agree with AG Witness Coppola's proposal?**

20 A30. No. It is premature to include any savings from the VSIP in the Company's revenue
21 requirement. The purpose of the VSIP was to realign the workforce to support the
22 changing nature of the Company's work and how the work is done, including an
23 increased focus on infrastructure investments, cybersecurity, and the clean energy
24 transition. Therefore, the Company continues to assess the need to fill key positions
25 which will impact any actual savings that may potentially be realized in 2025. While
26 the Company has made certain assumptions about the number of open positions as

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1 a result of the VSIP that will be filled in its estimated savings, these estimated
2 savings will continue to evolve as decisions regarding the actual number of positions
3 filled are made throughout the remainder of 2024. Rather than relying on an estimate
4 of potential savings that may be created by the VSIP, it is more prudent to wait until
5 any savings are actually realized which can then be reflected in the Company's
6 future revenue requirements.

7

8 **Q31. Does AG Witness Coppola's recommendation to include the estimated VSIP**
9 **savings as a reduction to the Company's revenue requirement reflect the costs**
10 **incurred by the Company in 2024 related to the VSIP?**

11 A31. No. Because the Company has not sought to recover the \$30.6 million in costs
12 related to the separation payments accrued in 2024, it would be unreasonable to
13 include a reduction to the Company's total O&M expense of the estimated savings
14 without any recognition of the costs incurred by the Company.

15

16 **Q32. What is CUB Witness Denzler's proposal regarding the VSIP?**

17 A32. CUB Witness Denzler proposes that all of the estimated gross savings related to the
18 VSIP of \$34.2 million be reflected as a reduction to the Company's O&M for the
19 projected test year (Denzler Direct, page. 14, lines 2-4). That is, CUB Witness
20 Denzler proposes that the labor and related savings of the employees that departed
21 under the VSIP be reflected, but not the estimated costs of the employees that will
22 be required to fill key positions.

23

24 **Q33. Is CUB Witness Denzler's proposal to include \$34.2 million of the estimated**
25 **VSIP savings as reduction to the Company's revenue requirement in this case**
26 **reasonable?**

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1 A33. No. As I explained relative to AG Witness Coppola's proposal to reflect the
2 estimated VSIP savings, it is simply premature to reflect any savings from the VSIP
3 because of the preliminary nature of the estimate. While AG Witness Coppola
4 correctly reflected the cost of new hires in his estimate of new savings, CUB
5 Witness Denzler proposes to include all of the estimated gross savings and excluded
6 any estimated costs for newly hired employees.

7
8 **Q34. What is the basis for CUB Witness Denzler's proposal to exclude the costs of**
9 **newly hired employees for those that departed under the VSIP?**

10 A34. CUB Witness Denzler claims that it is unreasonable for the Company's "rate payers
11 to bear the risk for the volatility of its staffing levels" (Denzler Direct, page 13,
12 lines 14-15).

13
14 **Q35. Do you agree with CUB Witness Denzler's proposal?**

15 A35. No. First, CUB Witness Denzler has seemingly assumed that the impetus of the
16 Company offering the VSIP was solely to reduce costs, as opposed to supporting
17 the Company's realignment of its workforce to meet changing needs, as I explained
18 relative to AG Witness Coppola's proposal. Second, while the precise number and
19 cost of employees required to meet the Company's changing workforce needs
20 continues to develop, it is patently unreasonable to assume the level of employees
21 hired between June 2024 and 2025 will be zero.

22
23 **Q36. Why is it unreasonable to assume that the Company will not fill any of the**
24 **positions vacated as a result of the VSIP?**

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1 A36. As reflected on Confidential Exhibit CUB-14C, 389 employees left the Company
2 in connection with the VSIP in the departments affected by the VSIP. In April
3 2024, it was expected that the Company would need to hire 184 new employees to
4 fill positions consistent with the realignment of the Company's workforce, as
5 described in my discussion of AG Witness Coppola's proposal. Plus, new
6 employees will continue to be added within the Company to meet changing
7 requirements, such as related to the execution of new major projects, which were
8 not reflected in the costs of the Company's new hires on Confidential Exhibit CUB-
9 14C. As the Company's workforce needs evolve during the remainder of 2024 and
10 2025, the Company will continue to add new employees to meet its requirements.
11 CUB Witness Denzler's dismissal of the Company's estimated costs of the new
12 hires based on the fact that the precise amount is uncertain ignores the dynamics of
13 on-going changes in the Company's workforce. While the hiring projections
14 included in Confidential Exhibit CUB-14C are preliminary and continue to evolve,
15 they represent the best estimate currently available.

16
17 **Q37. Are the Company's customers incurring any additional costs as a result of the**
18 **VSIP?**

19 A37. No. As explained in relation to my discussion of AG Witness Coppola's VSIP
20 proposal, the Company incurred \$30.6 million of costs in 2024 to implement the
21 VSIP but has not sought to recover that cost in its rates. Therefore, CUB Witness
22 Denzler's proposal to reflect the gross estimated savings from the VSIP while
23 ignoring both the costs to achieve incurred by the Company in 2024 and the
24 estimated costs to hire new employees would result in customers realizing all of the
25 savings of VSIP and none of the related expenses. This is clearly unreasonable.

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1 **Q38. Does this conclude your rebuttal testimony?**

2 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)
its rate schedules and rules governing the)
distribution and supply of electric energy, and)
for miscellaneous accounting authority.)

Case No. U-21534

REBUTTAL TESTIMONY

OF

NEAL T. FOLEY

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF NEAL T. FOLEY

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Neal T. Foley (he/him/his). My business address is One Energy Plaza,
4 Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC,
5 a subsidiary of DTE Energy Company as Director, Regulatory Affairs.

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to respond to certain positions taken by
14 Witnesses Evans and Duell on behalf of Michigan Public Service Commission
15 (MPSC or Commission) Staff (Staff); Witness Stults on behalf of Ann Arbor;
16 Witness Jester on behalf of the Michigan Environmental Council (MEC), Natural
17 Resource Defense Council (NRDC), Sierra Club (SC), and Citizens Utility Board
18 of Michigan (CUB) (collectively MNSC); Witness Denzler on behalf of CUB,
19 MEC, and NRDC (CUB-MN); Witness Richter on behalf of the Great Lakes
20 Renewable Energy Association (GLREA); Witnesses Koepfel and Watts on behalf
21 of Soulardarity and We Want Green, Too (collectively DAAO); Witnesses
22 Dauphinais and York on behalf of the Association of Businesses Advocating Tariff
23 Equity (ABATE); Witnesses Alvarez and Stephens on behalf of the Attorney
24 General (AG), MEC, and NRDC (collectively AG-MN); Witness Perry on behalf

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1 of Walmart; Witness Coppola on behalf of the AG; and Witness Bandyk on behalf
2 of CUB and MEC (CUB-M)

3

4 I will first provide a discussion on the impacts of capital and operating expense
5 disallowances, and then address intervenor positions related to the following topics:

- 6 • The linkage between reliability performance and capital investment,
7 including the Company's presentment of Interruption Cost Estimator (ICE)
8 Calculator output
- 9 • The Company's proposal to recover a portion of outage credits paid to
10 customers
- 11 • The Company's proposal to extend its Distribution Investment Recovery
12 Mechanism (Distribution IRM or IRM) through 2027
- 13 • The Company's proposed Storm Recovery Cost Sharing Mechanism
14 (SRCSM)
- 15 • The Company's proposed inflation rate
- 16 • The Company's proposed recovery of corporate membership dues
- 17 • The Company's use of a forward test year
- 18 • The linkage between incentive cost recovery and historical revenues

19

20 **Q4. Are you sponsoring any exhibits as part of your rebuttal testimony?**

21 A4. No.

22

23 **General impacts of capital and operating expense disallowances**

24 **Q5. What is the Company's overall reaction to Staff and intervenor testimony?**

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1 A5. As I discussed in my direct testimony, the Company is pursuing a strategic
2 imperative to rebuild, modernize, and automate its 46,000 miles of electric circuits
3 (the “grid”) such that by 2029 it can reduce the number of outages by 30% and
4 reduce the duration of outages when they do occur by 50%. This level of
5 improvement would result in better than industry average reliability. In addition,
6 the Company is continuing to modernize its power generation in pursuit of net zero
7 carbon emissions by 2050.

8

9 However, achieving these improvements requires significant capital investment –
10 roughly \$9 billion of investment in the grid and \$7 billion in investment in cleaner
11 generation between 2024 and 2028. Without timely recovery of these capital
12 investments and other operating costs, the Company’s ability to invest at planned
13 levels and meet its goals related to reliability and clean generation will be
14 challenged.

15

16 Across the testimonies filed by intervenors there were various recommended
17 disallowances of capital investment and operating expenses that would do just that
18 – challenge the ability of the Company to invest at planned levels and meet its
19 reliability and clean generation goals. The Company’s rebuttal witnesses clarify the
20 Company’s positions and discuss these proposed disallowances.

21

22 **Q6. How does the Company define “timely recovery” of capital investment and**
23 **operating expenses?**

24 A6. Timely recovery of capital investment and operating expenses means matching the
25 recovery of costs to the incurrence of those costs. Since 2008, this has been

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1 accomplished through the use of a forward test year where the Company projects
2 its costs and associated customer rates for a future 12-month period and, once
3 approved by the Commission, those rates are not implemented any earlier than the
4 start of the 12-month period. This structure allows customer rates to reflect the
5 actual costs being incurred by the Company.¹

6

7 Two dynamics can challenge the timely recovery of costs:

- 8 • A delay in recovery for otherwise prudent capital investments, creating
9 “Regulatory Lag” which can be costly to the Company
- 10 • The disallowance of unavoidable operating expenses, necessitating the
11 Company to try and absorb these costs, potentially through offsets
12 elsewhere

13

14 **Q7. How might the Company need to respond if there is not timely recovery of**
15 **costs?**

16 A7. Without timely recovery of costs the Company must consider re-timing capital
17 investment to a future period. For example, if proposed capital is disallowed in this
18 rate case, the Company must consider re-timing that capital investment to a future
19 period. If the disallowed capital is unavoidable (i.e., will be incurred regardless of
20 the outcome of this case), the Company must consider re-timing capital investment
21 elsewhere in its portfolio. For example, Company Witnesses Davis and Guillaumin
22 describe in their rebuttal testimony how certain Nuclear and Energy Supply
23 investments recommended for disallowance will in fact be incurred and why those
24 investments are reasonable and prudent.

¹ ABATE Witness Dauphinais recommends that the Commission reject the use of a forward test year starting on page 4 of his direct testimony; this is further discussed later in my rebuttal testimony

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1 Similarly, if operating expenses are disallowed but are unavoidable by the
2 Company, it must likewise consider capital investment re-timing to offset the
3 disallowed operating expense. More specifically, roughly \$15 of capital investment
4 results in \$1 of revenue requirement considering depreciation, return on rate base,
5 financing, etc.² Said differently, for every \$1 of operating costs that are disallowed
6 but cannot be avoided, the Company must consider re-timing capital investment by
7 roughly \$15 to offset the disallowance. If there are \$20 million of unavoidable
8 operating costs that the Company cannot recover from customers, it must consider
9 re-timing upwards of \$300 million of capital investment. For example, Company
10 Witnesses Hooper and Sharma describe in their rebuttal testimony how certain
11 Benefits and IT operating expenses recommended for disallowance will in fact be
12 incurred and why those investments are reasonable and prudent.

13

14 **Reliability Performance and Capital Investment**

15 **Q8. What intervenor positions related to the linkage between reliability**
16 **performance and capital investment are you addressing?**

17 A8. There are two intervenor positions I will address related to the linkage between
18 reliability performance and capital investment, both of which were presented by
19 Ann Arbor Witness Stults:

- 20 • How the Commission should address the Company's reliability
21 performance in this case
- 22 • The assertion that the Company's proposed investments will result in a "net
23 loss" of \$1 billion

² The exact revenue requirement associated with capital investment depends on the specific type of investment (e.g., IT, Distribution, etc.) given different depreciation rates and the authorized cost of capital; \$15 estimate reflects the average impact of test year capital investment

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1 **Q9. Can you summarize Ann Arbor Witness Stults’ recommendation on how the**
2 **Commission should address the Company’s reliability performance in this**
3 **case?**

4 A9. Yes. In her direct testimony, Witness Stults cites various measures of the
5 Company’s historical reliability and argues that “[c]ustomers continue to pay more
6 and more for service that is not improving.” (page 5). She goes on to recommend
7 that:

8
9 “...the Commission use its authority to consider the value of DTE’s service
10 to better tie DTE’s financial performance to its customers’ experience in
11 this case – through denying a large portion of DTE’s requested rate increase
12 and taking its performance into consideration when determining an
13 appropriate rate of return on equity (“ROE”).” (pages 8-9)

14
15 **Q10. Does the Company agree with Ann Arbor Witness Stults’ recommendation on**
16 **how the Commission should address the Company’s reliability performance**
17 **in this case?**

18 A10. No. To start, Witness Stults has not presented a specific recommendation on how
19 the Commission should “consider the value of DTE’s service” or take the
20 Company’s “performance into consideration” beyond suggesting the Commission
21 should deny a large portion of the Company’s request in this case.

22
23 The Company is committed to improving reliability such that by 2029 it will have
24 reduced the number of power outages by 30% and cut the duration of outages when

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1 they do occur by 50%. This commitment translates to better than industry average
2 All-Weather SAIDI³ performance.

3

4 However, this commitment can only be met with significant investment in the
5 Company's infrastructure supported by timely recovery of those investments.
6 Specifically, 70% of the Company's proposed revenue deficiency in this case is
7 related to capital investment, including the financing of those investments. As such,
8 denying a large portion of the Company's request because of its historic reliability
9 performance would have the exact opposite impact of what Witness Stults seeks to
10 achieve. Subjectively denying a large portion of the Company's request would
11 subsequently limit its ability to invest in its infrastructure and therefore diminish its
12 ability to realize reliability improvements.

13

14 Further, the Company notes that reliability performance is a key focus of pending
15 Case No. U-21400 regarding financial incentives and disincentives, otherwise
16 known as Performance Based Ratemaking (PBR). Through that case, in which the
17 City of Ann Arbor is a participant, the Commission is already exploring how to
18 strengthen the ties between the Company's reliability performance and its financial
19 outcomes.

20

21 As such, the Company believes the Commission should reject Witness Stults'
22 recommendation on how it should address the Company's reliability performance
23 in this case, and instead continue to address reliability performance through
24 pending Case No. U-21400.

³ System Average Interruption Duration Index

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1 **Q11. Can you summarize Ann Arbor Witness Stults' assertion that the Company's**
2 **proposed investments will result in a "net loss" of \$1 billion?**

3 A11. Yes. In her direct testimony on page 6, Witness Stults compares the Company's
4 total projected 2024-2028 capital investment of \$16 billion to the Interruption Cost
5 Estimator (ICE) Calculator output of \$15 billion presented by the Company and
6 concluded the Company's investments would result in a net loss of \$1 billion.

7
8 **Q12. Does the Company agree with Ann Arbor Witness Stults' assertion that the**
9 **Company's proposed investments will result in a "net loss" of \$1 billion?**

10 A12. No. Witness Stults is comparing two unrelated numbers. The \$16 billion represents
11 total Company 2024-2028 capital investment across cleaner generation and
12 distribution infrastructure (e.g., Energy Supply, Strategic Distribution, etc.). The
13 more than \$15 billion dollars of positive economic impact estimated using the ICE
14 Calculator is driven by reliability improvements realized through only a portion of
15 this investment. As such, comparing total cleaner generation and distribution
16 infrastructure investment to the ICE Calculator output which considers only a
17 portion of this investment is not a relevant comparison.

18

19 **Outage Credit Recovery**

20 **Q13. What Staff and intervenor positions related to the Company's proposal to**
21 **recovery certain outage credits are you addressing?**

22 A13. There are three Staff and intervenor positions I will address related to the
23 Company's proposal to recover certain outage credits:

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- 1 • Staff Witness Evans', MNSC Witness Jester's, and GLREA Witness
- 2 Richter's recommendations that recoverability of outage credits be more
- 3 limited than originally proposed by the Company
- 4 • DAAO Witness Koeppel's, DAAO Witness Watt's, and Ann Arbor Witness
- 5 Stults' recommendations to reject the Company's proposal to expand the
- 6 recoverability of outage credits
- 7 • DAAO Witnesses Koeppel's and Watt's recommendation to establish an
- 8 hourly outage credit

9

10 **Q14. Can you summarize Staff Witness Evans', MNSC Witness Jester's, and**
11 **GLREA Witness Richter's recommendations that recoverability of outage**
12 **credits be more limited than originally proposed by the Company?**

13 A14. Yes. In his direct testimony starting on page 8, Staff Witness Evans recommends
14 that the recoverability of outage credits be limited to the following:

- 15 • Duration-related outage credits:
 - 16 ○ Transmission operator
 - 17 ○ Another utility
- 18 • Frequency-related outage credits:
 - 19 ○ Transmission operator
 - 20 ○ Another utility
 - 21 ○ Public interference

22

23 Staff Witness Evans goes on to propose a methodology for calculating the specific
24 amount of frequency-related outage credits that would be recoverable in a specific

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1 year, and highlights Staff's openness to collaborating with the Company and other
2 intervenors on finalizing calculation methodology.

3
4 Similarly, MNSC Witness Jester argues:

5 "An outage attributable to a transmission operator or other utility must be fixed
6 by that party. It is therefore reasonable to provide a limited recoverability of bill
7 credits due to such outages, though the proper public policy would be that DTE
8 Electric must recover that cost from the responsible party." (page 10)

9
10 Besides outages caused by a transmission operator or other utility, MNSC Witness
11 Jester recommends rejecting the Company's proposal to recover outage credits paid
12 due to weather and animal interference.

13
14 Finally, GLREA Witness Richter takes a similar approach by recommending that
15 the Commission reject the Company's proposed recovery of outage credits caused
16 by weather events, and instead "[stick] to the very limited list of outage causes that
17 warrant recovery, enumerated in its order in U-20386 [sic]..." (page 67). He cites
18 the order in Case No. U-20836 page 367, which specifically identifies "customer
19 negligence" and "the transmission system operator" as outage causes where it is
20 reasonable for the Company to recover outage credits. He does not specifically
21 address the Company's proposed recoverability of outage credits paid as a result of
22 another utility or animal interference.

23
24 In summary, all three witnesses opposed the recoverability of outage credits related
25 to weather-driven events, but supported limited recoverability related to other

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1 events. The three witnesses differed somewhat in which outage codes they
2 specifically addressed in their testimonies and their final recommendations.

3

4 **Q15. Does the Company agree with Staff Witness Evans', MNSC Witness Jester's,**
5 **and GLREA Witness Richter's recommendations that recoverability of outage**
6 **credits be more limited than originally proposed by the Company?**

7 A15. Partially. The Company maintains its original proposal for outage credit recovery,
8 however it believes that the recommendation put forth by Staff Witness Evans is
9 reasonable.

10

11 In the Company's reading, Staff Witness Evans' recommendation does not seem to
12 be in conflict with either MNSC Witness Jester's or GLREA Witness Richter's
13 recommendations except potentially the inclusion of public interference as a
14 recoverable outage code for frequency-related outages recommended by Staff
15 Witness Evans. It is unclear if MNSC Witness Jester and/or GLERA Witness
16 Richter support this based on their direct testimony.

17

18 **Q16. Can you summarize DAAO Witness Koeppel's, DAAO Witness Watt's, and**
19 **Ann Arbor Witness Stults' recommendations to reject the Company's**
20 **proposal to expand the recoverability of outage credits?**

21 A16. Yes. DAAO Witness Koeppel recommends that the Commission fully reject the
22 Company's proposal and not allow for any recoverability of outage credits. He
23 argues "DTE Electric's proposed changes to its outage credit mechanism would
24 undermine the company's incentive to improve its reliability." (page 28)

25

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1 Similarly, DAAO Witness Watts recommends that the Commission fully reject the
2 Company's proposal and not allow for any recoverability of outage credits. She
3 argues that "[i]t is the Company's job to keep the lights on, and it should be
4 responsible for compensating us when it fails to do so." (page 9)

5
6 Finally, Ann Arbor Witness Stults recommends that the Commission fully reject
7 the Company's proposal and not allow for any recoverability of outage credits. She
8 argues that "[i]t is particularly unreasonable that DTE is asking to recover credits
9 for outages caused by weather or animal interference, which a better maintained
10 grid would withstand..." (page 14)

11
12 Ann Arbor Witness Stults allows for the possibility that some outage credit
13 recovery may be appropriate, but states "those circumstances would be extremely
14 limited and should be reviewed on a case-by-case basis." (page 15) She cites the
15 Commission's November 18, 2022, Order in Case No. U-20836 (November 2022
16 Order), page 367, which identifies "customer negligence" and "the transmission
17 system operator" as outage causes where recovery may be reasonable. However,
18 she concludes that "...attempting to recover a \$38 credit does not seem like the best
19 use of the Company's time...the outage credit amount is comically small in
20 comparison to the actual costs a customer incurs as a result of an outage, so perhaps
21 the Company should consider the rare cases where an outage may have been due to
22 a customer's negligence as a cost of doing business." (page 16)

23

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1 **Q17. Does the Company agree with DAAO Witness Koepfel's, DAAO Witness**
2 **Watt's, and Ann Arbor Witness Stults' recommendations to reject the**
3 **Company's proposal to expand the recoverability of outage credits?**

4 A17. No. The recommendations to reject all recoverability of outage credits conflicts
5 with the Commission's November 2022 Order which states:

6

7 "...it is reasonable that the company have the ability to recover outage credits
8 when the outage was caused by customer negligence or the transmission system
9 operator, among other limited circumstances as developed in collaboration with
10 the Staff." (page 367)

11

12 As such, the focus of outage credit recovery in this case should not be if
13 recoverability is appropriate since that has already been ordered upon by the
14 Commission. Instead, the focus should be on which outage credits are appropriate
15 for recovery. As such, the Commission should reject DAAO Witness Koepfel's,
16 DAAO Witness Watt's, and Ann Arbor Witness Stults' recommendations to deny
17 recoverability of all outage credits.

18

19 **Q18. Can you summarize DAAO Witnesses Koepfel's and Watt's recommendation**
20 **to establish an hourly outage credit?**

21 A18. Yes. In his direct testimony, Witness Koepfel recommends that the Commission
22 "...reconsider the establishment of hourly, progressive, automatic credits as DAAO
23 has previously argued for before the Commission." (page 28)

24

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1 Similarly, Witness Watts recommends that “[o]utage credits should be more
2 frequent and in higher dollar amounts.” (page 7) She specifically recommends that
3 “[i]nstead of the current flat rate, I support mandating an hourly credit, which would
4 make the credit more proportionate to the scale of the outage and subsequent costs.”
5 (page 8; footnote omitted)

6

7 **Q19. Does the Company agree with DAAO Witnesses Koeppel’s and Watt’s**
8 **recommendation to establish an hourly outage credit?**

9 A19. No. Service Quality and Reliability Standards (SQRS) for electric distribution
10 systems, and any credits to be paid to customers as a result of not meeting those
11 standards, are established through rulemaking and not through general rate cases.
12 Furthermore, hourly credits were specifically contemplated during rulemaking and
13 rejected by the Commission in its March 24, 2023, Order in Case. No. U-20629.
14 As such, not only is Witnesses Koeppel’s and Watt’s recommendation not
15 appropriate for this case, but it has also previously been considered and rejected by
16 the Commission. As such, it should be rejected in this case.

17

18 **Distribution Investment Recovery Mechanism (IRM)**

19 **Q20. What Staff and intervenor positions related to the Company’s Distribution**
20 **IRM proposals are you addressing?**

21 A20. There are four Staff and intervenor positions I will address related to the Company’s
22 IRM proposals:

- 23 • Staff Witness Evans’ recommendation to not extend the IRM as proposed
24 by the Company

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- 1 • ABATE Witness Dauphinais' recommendation to only extend the IRM
- 2 through 2026 with total authorized capital investment of \$275.0 million in
- 3 2026
- 4 • AG-MN Witnesses Alvarez's and Stephens' recommendation to not extend
- 5 the IRM as proposed by the Company
- 6 • Walmart Witness Perry's recommendation related to the timing of rate case
- 7 filings and IRM capital recovery
- 8

9 **Q21. Can you summarize Staff Witness Evans' recommendation to not extend the**
10 **Company's IRM?**

11 A21. Yes. In his direct testimony, Staff Witness Evans states that Staff does not support
12 extending the IRM through calendar year 2027. He explains:

13
14 "Staff does not want to have the Company locked into spending specific
15 amounts in those IRM programs for all of 2026 and 2027...when the U-21305
16 audit report, authored by the Liberty Consulting Group, will be finished
17 sometime in late summer or the fall, and the Commission may issue an order in
18 Case No. U-21400 regarding financial incentives and disincentives. The Liberty
19 audit report may have recommendations that could cause DTE Electric to
20 change spending amounts and programs included in the IRM." (page 13)

21
22 As it pertains to a potential gap in the implementation of the IRM, Staff Witness
23 Evans describes an example in which the Company would file a rate case on June
24 2, 2025, and receive an order in that case on April 1, 2026. He indicates that:

25

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1 “...a gap can be accommodated. Using the scenario described above, the
2 Company would receive the results of the Liberty audit later in 2024,
3 incorporate findings as appropriate into the partial year 2026 and likely calendar
4 year 2027 IRM Plans, and then include those plans and the IRM authorization
5 requests in the rate case filed on June 2, 2025. Knowing that an order would be
6 issued around April 1, 2026, and assuming that the 2026 IRM Plan Year would
7 start that same day, the Company could send the Partial Year 2026 IRM
8 Investment Plan out to Staff and intervenors on December 1, 2025, and then
9 schedule the forum on or before February 1, 2026.” (pages 14-15)

10

11 **Q22. Does the Company agree with Staff Witness Evans’ recommendation to not**
12 **extend the IRM?**

13 A22. The Company appreciates the balance Staff Witness Evans seeks to strike a balance
14 between incorporating the findings from pending Case No. U-21305 (Distribution
15 Audit) and pending Case No. U-21400 (PBR) into potential future iterations of the
16 IRM while also ensuring the benefits of the IRM do not lapse. The Company
17 supports both Staff’s and the Commission’s desire to incorporate the findings from
18 these cases in future iterations of the IRM⁴ and will seek to do so at the earliest
19 opportunity. However, the Company respectfully disagrees with Staff’s position
20 that the most appropriate path forward is to let the IRM lapse at the end of 2025
21 only to potentially be re-authorized several months later at the conclusion of the
22 Company’s next general rate case.

23

⁴ In its Order in Case No. U-21297 which originally authorized the IRM, the Commission cited pending Case No. U-21305 and Case No. U-21400 as reasons to only authorize the first two years of the IRM.

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1 More specifically, the Company does not believe that extending the IRM would
2 result in it being “locked into specific spending amounts.” Instead, as indicated in
3 my direct testimony on page 60, adjustments to 2026 and/or 2027 IRM
4 authorization could be made in future general rate cases, even if IRM authorization
5 for those years is granted in the current case. For example, IRM authorization could
6 be granted in this case for 2026 and 2027 at the investment levels proposed by the
7 Company. Then, in a future general rate case (e.g., filed on June 2, 2025 in Staff
8 Witness Evans’ example) adjustments to that authorization could be made based on
9 the findings of Case No. U-21305 and Case No. U-21400. This updated
10 authorization would become effective at the conclusion of that rate case (e.g., April
11 1, 2026 in Staff Witness Evans’ example). The Company believes such an
12 approach, which would potentially update the amount authorized for IRM treatment
13 mid-year, is preferable to allowing the IRM to lapse at the end of 2025.

14

15 In addition, the Company has concerns about how a lapse in the IRM would be
16 accommodated. In his example, Staff Witness Evans suggests that the Company
17 could file a partial-year 2026 IRM Investment Plan in December 2025, and
18 schedule a subsequent stakeholder forum in February 2026, before the IRM is
19 authorized at the conclusion of the Company’s next rate case.

20

21 Such an approach, which has the Company submitting an IRM Investment Plan
22 before IRM authorization is granted by the Commission, would lead to
23 inefficiencies in the process. The Company would need to prepare the plan
24 assuming a certain level of future IRM authorization, and Staff and other
25 stakeholders would need to invest significant resources to review the plan. If a

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1 Commission Order differed from the assumed level of IRM authorization in the
2 plan, the Company would need to develop a revised plan and conduct new
3 stakeholder reviews, a process that would likely require several months.

4

5 **Q23. What does the Company recommend in response to Staff Witness Evans’**
6 **testimony?**

7 A23. The Company maintains its original proposal to extend the Company’s IRM
8 through 2027 at the proposed investment levels. As discussed above, such
9 authorization would not preclude the Commission from ordering adjustments to the
10 authorized amounts in a future rate case once pending Case Nos. U-21305 and. U-
11 21400 have concluded. Importantly, such an approach would ensure the ongoing
12 and efficient operation of the IRM and avoid the challenges and complexities that
13 a lapse in its operation would introduce. In addition, an extension will ensure the
14 customer benefits realized through the IRM do not lapse. These benefits include
15 certainty of investment for its originally intended purpose, customer protections in
16 the event of underinvestment, and additional opportunities for Staff and other
17 intervenors to review and provide feedback on the Company’s investment plans
18 and the execution of those plans.

19

20 However, if the Commission does not find it appropriate to approve a two-year
21 extension at the proposed investment levels, the Company recommends at a
22 minimum that the Commission approve a one-year extension at the investment
23 levels previously authorized for 2025 (i.e., IRM Year 2). It is valuable to the
24 Company to have clear visibility and certainty of the work it can execute in a
25 specific year well in advance of project execution. Such certainty allows the

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1 Company to procure the appropriate resources, materials, permits, etc. to ensure
2 efficient and timely execution.

3

4 While not preferred by the Company, a one-year extension would provide it with
5 that certainty and allow it to develop a robust IRM Investment Plan for 2026.

6

7 **Q24. Can you summarize ABATE Witness Dauphinais' recommendation to only**
8 **extend the IRM through 2026 including \$275 million of 2026 investment?**

9 A24. Yes. In his direct testimony, ABATE Witness Dauphinais argues that the
10 Commission should only authorize Year 3 (i.e., 2026) of the Company's IRM and
11 that IRM treatment for Year 3 should be capped at \$275 million. Witness
12 Dauphinais argues:

13

14 "DTE's distribution IRM should not at this time be dramatically expanded and
15 extended as proposed by DTE given DTE's distribution IRM is still in its
16 infancy. Year 1 just barely commenced seven months prior to the filing of this
17 testimony and the first DTE distribution IRM reconciliation will not commence
18 until sometime in 2025" (pages 15-16)

19

20 and

21

22 "The term of the authorized distribution IRM for DTE should at this time be
23 limited to no longer than truly necessary, as the Commission concluded in its
24 Final Order in Case No. U-21297, until potential insights from Case Nos. U-

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1 21400 and U-21305 are gained to better inform continuation of the distribution
2 IRM.” (page 16)

3
4 ABATE Witness Dauphinais goes on to acknowledge the Company’s concerns
5 related to “stopping and starting” of the IRM and states he does not oppose a one-
6 year extension of the IRM through 2026 with only the following four programs
7 authorized for IRM treatment in 2026 at the Company’s proposed investment
8 levels:

- 9 • Conversions (\$190 million of 2026 investment)
- 10 • Subtransmission Redesign and Rebuild (\$55 million of 2026 investment)
- 11 • Breaker Replacement (\$15 million of 2026 investment)
- 12 • URD Replacement (\$15 million of 2026 investment)

13

14 **Q25. Does the Company agree with ABATE Witness Dauphinais’ recommendation**
15 **to only extend the IRM through 2026 including \$275 million of 2026**
16 **investment?**

17 A25. Partially. While the Company agrees that the IRM is still in its early stages, the
18 Company does not believe this is a compelling reason to limit its growth if IRM
19 investments are otherwise warranted. Subjectively limiting the size of the IRM also
20 limits the benefits that can be realized through its use such as the additional
21 certainty of investment for its originally authorized purpose, customer protections
22 in the event of underinvestment, and additional opportunities for Staff and
23 intervenor input.

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1 In addition, like Staff Witness Evans discussed previously, ABATE Witness
2 Dauphinais cites pending Case Nos. U-21305 and U-21400 as reasons to limit the
3 term of the IRM. As described previously in my rebuttal testimony, authorizing an
4 extension of the IRM as proposed by the Company does not preclude the
5 Commission from ordering adjustments to that authorization in future rate cases
6 once pending Case Nos. U-21305 and U-21400 have concluded. As such, the
7 Company does not believe this is a compelling reason to limit the term or scope of
8 the IRM.

9
10 With that said, as described previously in my rebuttal testimony, if the Commission
11 does not find it appropriate to approve a two-year extension at the proposed
12 investment levels, the Company recommends at a minimum that the Commission
13 approve a one-year extension of the IRM at the investment levels previously
14 authorized for 2025 (i.e., IRM Year 2). This is similar to the recommendation put
15 forth by ABATE Witness Dauphinais and represents a better, more efficient path
16 forward than allowing the IRM to lapse at the end of the 2025.

17

18 **Q26. Can you summarize AG-MN Witnesses Alvarez's and Stephens'**
19 **recommendation to not extend the IRM through 2027?**

20 A26. Yes. In his direct testimony, Witness Alvarez recommends that the Commission
21 reject the Company's proposal to extend the IRM through 2027. He first asserts:

22

23 "Rider cost recovery shifts capital spending risk from shareholders to
24 customers, shifts prudence responsibilities from utilities to intervenors, and
25 introduces moral hazard into utility distribution grid investment plan

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1 development. I discussed these unintended consequences at length in my
2 testimony in U-21297...” (page 29; footnote omitted)

3

4 He goes onto argue, starting on page 29, that the IRM limits the Commission’s
5 “practical ability to order a cost disallowance” which results in a moral hazard since
6 “utilities have nothing to lose, and everything to gain, by proposing more capital
7 spending than they would otherwise spend under traditional ratemaking.”

8

9 As it relates to the IRM procedural mechanisms approved by the Commission in
10 Case No. U-21297, AG-MN Witness Alvarez argues they are not sufficient to
11 address his concerns. He states:

12

13 “These two procedural mechanism – the preview and reconciliation – offer little
14 more than lip service to capital spending governance. Since the Commission set
15 a cap on spending, providing intervenors with a list of planned projects up to
16 the authorized IRM spending level conceivably *might* allow participating
17 intervenors with technical expertise to advocate for shifted projects – *e.g.*, start
18 PTMM on a particular circuit sooner – but changes seem unlikely (DTE is
19 unlikely to shift course so close to start of the IRM year). Moreover, the preview
20 process still leaves the burden on the intervenors to counter DTE’s plan, not the
21 other way around. The reconciliation contested proceeding is similarly
22 unredeeming – the money will already have been spent.” (page 33)

23

24 In his testimony, AG-MN Witness Stephens discusses the appropriateness of IRM
25 treatment for the specific programs proposed by the Company. In summary, he

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1 argues that none of the programs proposed by the Company are suitable for IRM
2 treatment in 2026 and 2027.

3

4 **Q27. Does the Company agree with AG-MN Witnesses Alvarez's and Stephens'**
5 **recommendation to not extend the IRM through 2027?**

6 A27. No. To start, and as admitted by Witness Alvarez on page 29 of his direct testimony,
7 much of his argument against the use of the IRM is simply a restatement of the
8 arguments that were made in Case No. U-21297 when the Commission originally
9 authorized the IRM. Witness Alvarez presents no new arguments or evidence that
10 suggests the Commission erred when it was originally presented these same
11 arguments in Case No. U-21297 and ultimately concluded that authorizing the IRM
12 was the appropriate path forward.

13

14 The Company also disagrees that the IRM planning and reconciliation processes
15 approved by the Commission in Case No. U-21297 are simply "lip service" to
16 capital spending governance as asserted by AG-MN Witness Alvarez. To the
17 contrary, as stated by the Commission in its December 1, 2023, Order in Case No.
18 U-21297:

19

20 "The filing of the IRM Investment Plan at least four months prior to the start of
21 each plan year will allow for a more meaningful review by both the Staff and
22 other interested stakeholders. Further, the submission of the plan to all
23 intervening parties, along with providing a forum for interested parties to raise
24 concerns, will allow for additional collaboration and input into the proposed
25 investments." (page 289)

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4

“In addition to plan review, a contested reconciliation process will provide additional opportunities for input from interested parties. Further, developing a record in a contested proceeding will provide even greater transparency and opportunity for review of the reasonableness and prudence of the company’s expenditures, as well as accept input to address equity concerns such as those raised by the DAAOs to avoid racialized disparities in service.” (page 290)

10

11

Simply put, AG-MN Witness Alvarez’s assertion on page 33 of his direct testimony that “the preview process still leaves the burden on the intervenors to counter DTE’s plan” is unfounded. Not only is IRM authorization granted in a contested rate case, both in terms of the programs and investment levels, the Company must provide an annual forum before execution begins where intervenors can raise concerns with the Company’s plans and then defend those investments in a contested reconciliation proceeding.

18

19

AG-MN Witness Stephens’ arguments related to the specific capital programs proposed for IRM treatment in 2026 and 2027 are addressed by the Company’s witnesses that sponsor those programs.

22

23

Q28. Can you summarize Walmart Witness Perry’s recommendations related to the timing of rate case filings and IRM capital recovery?

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1 A28. Yes. Walmart Witness Perry recommends that if the Commission authorizes the
2 extension of the IRM:

3

4 "...it should also require the Company to file a base rate case at the earliest
5 possible date when the assets can be included in the Company's test year.
6 Additionally, the Commission should deny recovery of any costs exceeding
7 what was approved in the Company's last rate case for IRM plan years 2024
8 and 2025, requiring the Company to recover these additional costs through base
9 rates instead." (page 22)

10

11 **Q29. Does the Company agree with Walmart Witness Perry's recommendations**
12 **related to the timing of rate case filings and IRM capital recovery?**

13 A29. No. The Company believes the recommendations put forth by Walmart Witness
14 Perry are unnecessary. As ordered by the Commission, the IRM includes an annual
15 contested reconciliation that addresses the prudence of IRM investments made in
16 the previous year. If the Commission were to find that a particular investment was
17 not prudent, then the Company would return collected funds to ratepayers and no
18 longer recover that investment through the IRM surcharge. As such, there is no
19 need to subjectively define the timing of future rate cases since IRM investment
20 prudence and recovery is already being addressed using the currently approved
21 processes.

22

23 Further, as proposed by the Company and ordered by the Commission, the
24 Company cannot unilaterally increase the size of the IRM surcharge for 2024 and
25 2025. The recovery of any investment made in those years above what was

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1 authorized for the IRM would need to be sought by the Company in a general rate
2 case.

3
4 Said differently, the concerns raised by Walmart Witness Perry are already being
5 addressed under the existing processes and therefore his specific recommendations
6 should be rejected.

7

8 **Storm Recovery Cost Sharing Mechanism (SRCSM)**

9 **Q30. What Staff and intervenor positions related to the Company's proposed**
10 **SRCSM are you addressing?**

11 A30. There are three Staff and intervenor positions I will address related to the
12 Company's proposed SRCSM:

- 13 • Staff Witness Duell's recommendation to reject the Company's proposed
14 SRCSM
- 15 • CUB-MN Witness Denzler's recommendation to reject the Company's
16 proposed SRCSM
- 17 • Ann Arbor Witness Stults' recommendation to reject the Company's
18 proposed SRCSM

19

20 **Q31. Can you summarize Staff Witness Duell's recommendation to reject the**
21 **Company's proposed SRCSM?**

22 A31. Yes. In her direct testimony, Staff Witness Duell recommends the SRCSM not be
23 approved, stating in part:

24

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1 “Staff believes this mechanism should not be approved because 1) Staff is
2 supporting the full-service restoration expense for the test year; 2) the
3 Commission rejected similar mechanisms in prior cases U-20963, U-20697,
4 and U-21389; and 3) Staff would like to see results from the third-party audit
5 to further determine cost savings in storm restoration expenses.” (page 10)

6

7 Staff Witness Duell goes on to argue that customers may never see a benefit from
8 the proposed SRCSM and that it would weaken the incentives for the Company to
9 control storm restoration costs.

10

11 **Q32. Does the Company agree with Staff Witness Duell’s recommendation to reject**
12 **the Company’s proposed SRCSM?**

13 A32. No. To start, while the Company appreciates Staff’s support of the projected test
14 year storm restoration expense, the Company does not believe that support is a
15 justification to reject the proposed SRCSM. As described in my direct testimony,
16 the current approach to storm restoration O&M expense recovery (which Staff is
17 supporting) does not address the uncertainty and variability of these expenses in
18 any given year and exposes both customers and the Company to financial risk. The
19 proposed SRCSM is designed to address this uncertainty and variability by
20 *enhancing* the existing approach to recovering storm restoration expenses, not by
21 replacing it.

22

23 Next, the Company disagrees that the Commission has rejected similar mechanisms
24 in cases U-20963, U-20697, and U-21389. In all three of those cases, Consumers
25 Energy proposed a *cost tracker*. In this case the Company has proposed a *cost*

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1 *sharing mechanism*, which is fundamentally different. This fundamental difference
2 provides sufficient justification for the Commission to assess the Company's
3 proposal on its own merits and not base its decision on previous orders.

4 Further, the Company disagrees that reviewing the findings of the pending Case
5 No. U-21305 related to the Company's Distribution Audit should be a prerequisite
6 to approving the SRCSM proposed by the Company. The SRCSM is designed to
7 address the uncertainty and volatility of storm restoration O&M costs and doesn't
8 preclude the Company from using the findings of the Distribution Audit to pursue
9 cost savings in the future. If the findings of the Distribution Audit suggest areas of
10 cost savings, the Company can pursue those savings which would ultimately be
11 incorporated into its forecasts of future storm restoration O&M costs. These
12 activities are unrelated to the SRCSM which would immediately improve upon the
13 current approach to storm restoration O&M cost recovery.

14

15 The Company also disagrees with the suggestion that customers may never see a
16 benefit from the proposed SRCSM. The only way for such an outcome to occur
17 would be if actual storm restoration costs were *always* above the projected level of
18 costs. Given the volatility of these costs as discussed in my direct testimony, this
19 outcome is unlikely to occur.

20

21 Finally, the Company believes that the 50% of sharing of costs that deviate from
22 projections maintains a significant incentive to control these costs.

23

24 In summary, the Company continues to believe that implementing the SRCSM
25 would improve upon the existing approach to storm restoration O&M recovery by

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1 maintaining a strong incentive to control costs while also better protecting
2 customers and the Company against financial risks.

3

4 **Q33. Can you summarize CUB-MN Witness Denzler's recommendation to reject**
5 **the Company's proposed SRCSM?**

6 A33. Yes. In his direct testimony, CUB-MN Witness Denzler recommends that the
7 Commission reject the Company's proposed SRCSM. He first asserts that the
8 proposed SRCSM "skews the share of risk significantly in favor of the Company,
9 at the expense of ratepayers." (page 3) He goes on to explain "[i]f the increased
10 storm severity projected by the Company are realized, it is much more likely for
11 costs to exceed projections than to be under projections." (page 4)

12

13 CUB-MN Witness Denzler also asserts that the proposed SRCSM "creates a strong
14 misalignment of incentives, when the Company's historical storm performance is
15 already very poor." (page 3) He goes on to explain

16

17 "...the Company would be more incentivized to control costs if it had to absorb
18 100% of every incremental dollar that is spent...the Company's proposal would
19 mean that every incremental restoration dollar spent now would cost the
20 Company only \$0.50, when that dollar falls into the Storm category. This would
21 create a financial incentive for the Company to extend the duration of Storms
22 and perform additional work under the Storm umbrella as it would be 50%
23 cheaper than if performed after Storm-close." (page 6)

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1 CUB-MN Witness Denzler further argues that “[f]urther misalignment of
2 incentives would be driven by the fact that failure to keep storm restoration costs
3 down would increase the size of the five-year trailing average storm cost projection
4 that customers must pay.” (page 7)

5 In addition to rejecting the proposed SRCSM, CUB-MN Witness Denzler
6 recommends:

7

8 “...the Commission order DTE to develop Storm performance criteria that
9 include outage restoration, estimate accuracy, resource productivity, and
10 financial responsibility specific to Storm scenarios and tie-bar financial
11 recovery of excess Storm restoration costs to the Company’s performance in
12 these areas.” (page 8)

13

14 and

15

16 “In light of the fact that the Company effectively receives compensation for
17 weather volatility, should the Commission approve the Company’s storm
18 recovery cost sharing proposal despite my recommendation, I recommend the
19 Commission reduce the rate of return it authorizes on these costs.” (page 8)

20

21 **Q34. Does the Company agree with CUB-MN Witness Denzlers’s recommendation**
22 **to reject the Company’s proposed SRCSM?**

23 A34. No. To start, the Company disagrees with CUB-MN Witness Denzler’s assertion
24 that the proposed SRCSM skews the share of risk in favor of the Company. As
25 discussed in my direct testimony starting on page 63, storm restoration O&M costs

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1 are uncertain and volatile. The proposed SRCSM protects both customers and the
2 Company from financial risk through the equal sharing of costs that deviate from
3 projections.

4

5 Further, if the Company consistently spends more on storm restoration O&M than
6 is projected as discussed by CUB-MN Witness Denzler, this will have the impact
7 of raising those projections and the amount recovered from customers in future
8 years under the current approach. If this were to occur, the SRCSM would offer
9 even greater protections than it does today since the amount being recovered
10 through rates would be greater than it is today. Based on both historical costs and
11 the mechanics of the current approach, the suggestion that the SRCSM would skew
12 the share of risk in favor of the Company is unfounded.

13

14 As it pertains to incentives, CUB-MN Witness Denzler's assertion that the
15 Company would be incentivized to extend the duration of a storm reflects a
16 fundamental misunderstanding of how storm cost accounting works in practice.
17 Storms are well-defined events that have an identifiable start, end, and impacted
18 population of customers. When a storm occurs, any costs incurred restoring
19 impacted customers are accounted for as a storm expense⁵, and storm expenses
20 continue to accumulate until all customers are restored. Expenses incurred for
21 reasons other than restoring impacted customers are not considered storm expenses.
22 Therefore, the Company cannot elect to extend the duration of storm to ensure
23 increased cost recovery.

24

⁵ This includes both initial temporary repairs to ensure customers are restored, and follow-up permanent repairs

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1 In response to CUB-MN Witness Denzler's recommendation that the Company
2 create storm performance criteria and link storm expense recovery to performance
3 against those criteria, the Company notes that storm performance is already being
4 addressed in the following two areas:

- 5 • The SQRS, which sets standards of service related to the frequency and
6 duration of storm-related outages
- 7 • Pending Case No. U-21400 related to financial incentives and disincentives,
8 otherwise referred to as PBR; an order in this case is still pending

9

10 Further, CUB-MN Witness Denzler's recommendation that the "Commission
11 reduce the rate of return it authorizes on these costs" if it were to approve the
12 SRCSM is irrelevant. The SRCSM only addresses storm restoration O&M
13 expenses, for which the Company earns no return. As such, the Commission cannot
14 reduce the rate of return on these costs.

15

16 In summary, the Company disagrees with CUB-MN Witness Denzler's
17 recommendations and instead recommends that the Commission approve the
18 SRCSM and continue to address storm restoration performance through the SQRS
19 and pending Case No. U-21400.

20

21 **Q35. Can you summarize Ann Arbor Witness Stults' recommendation to reject the**
22 **Company's proposed SRCSM?**

23 A35. Yes. In her direct testimony, Ann Arbor Witness Stults recommends that the
24 Commission reject the Company's proposed SRCSM. First, Ann Arbor Witness
25 Stults argues that the Company's proposal "...creates problematic incentives for

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1 the Company, including motivating the Company to play a shell game with capital
2 recovery for repairs, because repairs done before a storm or after a storm would be
3 recovered differently from those that took place immediately after a storm.” (page
4 17)

5 Ann Arbor Witness Stults goes on to argue that the proposed SRCSM would
6 “...reward the Company for projecting very high estimates of storm restoration
7 costs, so it appears to “underspend” its target. Overestimations would allow the
8 Company to recover some monies that were never spent and thus would normally
9 not be properly included in rate recovery.” (pages 17-18)

10

11 Finally, Ann Arbor Witness Stults argues the proposed SRCSM “...creates a
12 situation in which ratepayers will be paying for investments to improve the
13 resiliency of the grid...which should result in lower storm restoration costs, and
14 then when those investments are successful in reducing such costs, half of the
15 benefit of reduced storm restoration costs (i.e., reduced rates) will not flow to the
16 ratepayers.” (page 18) In addition, Witness Stults asserts the proposed SRCSM:

17

18 “...would allow the Company to keep half of the savings that result from
19 coming up to normal maintenance standards. It would be unreasonable for the
20 Company not to pass these savings on to the ratepayers who funded the more
21 resilient grid and suffered due to DTE’s decisions to underspend on O&M for
22 more than a decade.” (page 18)

23

24 **Q36. Does the Company agree with Ann Arbor Witness Stults’ recommendation to**
25 **reject the Company’s proposed SRCSM?**

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1 A36. No. Ann Arbor Witness Stults' testimony reflects a fundamental misunderstanding
2 of both how storm restoration O&M costs are recovered today and how the
3 Company is proposing to improve that process through the SRCSM. First, Ann
4 Arbor Witness Stults suggests the Company could play a "shell game with capital
5 recovery" if the SRCSM were to be approved. However, the SRCSM does not
6 impact capital recovery. It is a mechanism to address the uncertainty and variability
7 of O&M expenses only. Capital investment and the recovery of that investment are
8 unaffected by the Company's proposed SRCSM.

9
10 Second, Ann Arbor Witness Stults suggests the SRCSM would "reward the
11 Company for projecting very high estimates of storm restoration costs." However,
12 the current approach to projecting storm restoration O&M expenses is formulaic
13 based on historical average spending adjusted for inflation. Based on this, the
14 Company cannot simply project a very high estimate as suggested by Witness
15 Stults.

16
17 Finally, Ann Arbor Witness Stults argues that the proposed SRCSM "...would
18 allow the Company to keep half of the savings that result from coming up to normal
19 maintenance standards. It would be unreasonable for the Company not to pass these
20 savings on to the ratepayers." However, this argument fails to acknowledge that
21 under the current approach the Company is allowed to keep *all* savings if actual
22 storm restoration O&M expenses are less than projected. Under the proposed
23 SRCSM, more savings would be returned to customers than the current approach.

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1 In addition, over time if the Company reduces storm restoration O&M costs, as
2 suggested by Ann Arbor Witness Stults, customers would *fully* capture these
3 savings through lower projected costs that are recovered through rates.

4

5 **Inflation Rate**

6 **Q37. What intervenor positions related to the Company's proposed inflation rates**
7 **are you addressing?**

8 A37. There are two intervenor positions I will address related to the Company's proposed
9 inflation rates:

- 10 • AG Witness Coppola's and ABATE Witness York's recommendation to
11 reject the Company's proposed "blended" inflation rate and instead use an
12 alternative rate
- 13 • CUB-M Witness Bandyk's recommendation to reduce the Company's
14 proposed inflation rates to account for productivity improvements

15

16 **Q38. Can you summarize AG Witness Coppola's and ABATE Witness York's**
17 **recommendation to reject the Company's proposed "blended" inflation rate**
18 **and instead use an alternative rate?**

19 A38. Yes. In his direct testimony, AG Witness Coppola argues:

20

21 "The use of a "blended rate" inclusive of wage increases has been rejected in
22 recent general rate cases and the Commission should do so again in this rate
23 case. Instead, the Commission has previously adopted the use of the CPI-Urban
24 area inflation rates to forecast future cost increases when warranted." (page
25 102)

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Instead, he recommends the use of CPI-Urban inflation rates of 2.4% for 2024 and

3

2.2% for 2025 based on the “February 2024 Blue Chip Report.”

4

5

Similarly, ABATE Witness York recommends that the Commission reject the

6

Company’s 3% labor inflation rate, arguing that “[t]here are many moving pieces

7

with respect to the Company’s labor expense.” (page 12) She specifically cites the

8

number of employees and employees leaving and being replaced by lower wage

9

employees as variables that could impact labor wage escalation. Instead, she

10

recommends the use of the Real GDP Chained Price Index for both labor and non-

11

labor costs, arguing it is superior to the CPI as proposed by the Company for non-

12

labor costs because:

13

14

“...the basket of goods and services is updated to reflect what people are

15

actually buying. This is unlike the CPI, which uses a fixed basket for a set

16

period. This makes the Real GDP index more responsive to consumer

17

substitution – if prices of certain goods rise, people might switch to less

18

expensive alternatives, and the index will reflect that change. In addition, the

19

CPI can be heavily weighted by the cost of medical expenses, which is not

20

reflective of the cost of utility expenses.” (page 13)

21

22

ABATE Witness York concludes by highlighting that her recommended approach

23

“...does not cure the deficiency for changes in the tenure of employees, but at least

24

relies on independent factors to project escalations in labor costs.” (page 13)

25

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1 **Q39. Has ABATE Witness York proposed her recommended methodology in past**
2 **cases?**

3 A39. No. In the Company's last general rate case (i.e., Case No. U-21297), ABATE
4 Witness York proposed using the Company's average growth rate of normalized
5 annual O&M expenses to project future escalations.

6

7 In the Company's general rate case before Case No. U-21297 (i.e., Case No. U-
8 20836), ABATE Witness York advocated for the use of the projected CPI increases
9 as published by Blue Chip Economic Indicators for escalating both non-labor and
10 labor O&M.

11

12 **Q40. Does the Company agree with AG Witness Coppola's and ABATE Witness**
13 **York's recommendations to reject the Company's proposed "blended"**
14 **inflation rate and instead use an alternative rate?**

15 A40. No. To start, the Company disagrees with AG Witness Coppola's assertion that
16 "[t]he use of a "blended rate" inclusive of wage increases has been rejected in recent
17 general rate cases." The Commission approved the use of a composite inflation rate
18 in its November 18, 2022 Order in Case No. U-20836 and subsequently maintained
19 its approval of this approach in its December 1, 2023 Order in Case No. U-21297.

20

21 Furthermore, the use of a composite rate continues to best reflect the inflationary
22 pressures faced by the Company. It rightfully separates labor inflation, which is
23 subject to Company-specific dynamics like collective bargaining agreements, from
24 non-labor inflation. Neither AG Witness Coppola nor ABATE Witness York

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1 provide evidence that suggests the Commission erred when it approved the use of
2 a composite rate in the Company's most recent general rate cases.

3

4 As it relates to the specific inflation rates proposed by the witnesses, the Company
5 notes that AG Witness Coppola's recommended use of the CPI-Urban rate is
6 similar to the CPI-Urban rate proposed by the Company for escalating non-labor
7 costs. The only difference is the source of the rate – the Company proposed the
8 CPI-U rate as published by S&P/IHS Markit and approved in previous cases, while
9 AG Witness Coppola proposed the CPI-U rate as published in the "Blue Chip
10 Report." AG Witness Coppola has not provided any evidence as to why the rate
11 published in the "Blue Chip Report" is superior to the rate published in by S&P/IHS
12 Markit previously approved by the Commission for escalating non-labor costs.
13 Further, the CPI-U rate proposed by AG Witness Coppola, captured in Exhibit AG-
14 2, appears to only reflect the first half of 2025. This is inappropriate since the
15 Company's forward test year in this case extends for full year 2025.

16

17 Similarly, while ABATE Witness York provides a description of the Real GDP
18 Chained Price Index, she has not provided compelling evidence that it is superior
19 to the CPI-Urban rate in projecting *utility-specific* non-labor costs. She discusses,
20 for example, how the Real GDP Chained Price Index accounts for consumer
21 substitution, but it is not clear that this is appropriate for utility-specific costs,
22 especially considering the potentially limited ability a utility has for substitution.

23

24 Further, the CPI is a well-established and widely used measure of inflation. The
25 basket of goods incorporated in the CPI is updated periodically. According to the

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1 U.S. Bureau of Labor Statistics (BLS), these updates are made to “reflect more
2 recent consumer spending patterns; this provides a logical opportunity to rework
3 the item classification scheme so that it will recognize the emergence of new items,
4 the changes to existing items and their relative importance, and the ways that people
5 view consumer goods and services.”⁶

6

7 Given the lack of evidence that the proposed rate is superior to the previously
8 approved CPI-Urban rate used for escalating non-labor costs, ABATE Witness
9 York’s recommendation should be rejected.

10

11 **Q41. Can you summarize CUB-M Witness Bandyk’s recommendation to reduce to**
12 **the Company’s proposed inflation rates to account for productivity**
13 **improvements?**

14 A41. Yes. In his direct testimony, CUB-M Witness Bandyk argues that the Company’s
15 proposed inflation rates should be reduced to account for potential productivity
16 gains. He explains:

17

18 “While it is prudent to expect that costs will be affected by inflation, it is also
19 prudent to factor in how productivity gains may mitigate inflation. Ms. Uzenski
20 does not make any adjustment for productivity. It is reasonable to expect that a
21 business will, on average, make some productivity gains year to year.” (page 3)

22

23 CUB-M Witness Bandyk goes on to cite Bureau of Labor Statistics (BLS) on
24 multifactor productivity for the private nonfarm sector and labor productivity for

⁶ <https://www.bls.gov/cpi/additional-resources/revision-1998-item-structure.htm> (accessed August 13, 2024)

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1 Michigan. He argues that DTE “does not face the competitive pressures to improve
2 productivity that can be found in non-regulated industries” (page 4) and reducing
3 inflation to account for productivity gains “would simulate the effect of
4 productivity improvements on DTE’s costs” (page 4).

5

6 He ultimately recommends that the Company’s inflation rates be reduced based on
7 the historical BLS productivity improvement data cited previously in his testimony.

8

9 **Q42. Does the Company agree with CUB-M Witness Bandyk’s recommendation to**
10 **reduce the Company’s proposed inflation rates to account for productivity**
11 **improvements?**

12 A42. No. Through its Continuous Improvement (CI) program, the Company strives to
13 identify and execute sustainable productivity improvements and leverage new
14 technology to help control the Company’s cost structure over the long term. Any
15 known and measurable cost reductions related to productivity gains would be
16 embedded in each business unit’s financial exhibits.

17

18 As such, adjusting the Company’s inflation rates downward to account for potential
19 productivity gains when productivity gains are already embedded in each business
20 unit’s financial exhibits would represent a “double counting” of productivity
21 improvements. In addition, applying a blanket productivity adjustment as suggested
22 by CUB-M Witness Bandyk is akin to setting a long-term productivity target that
23 conflicts with the “known and measurable” nature of forward test year projections.
24 Instead, the current approach to embedding productivity gains into each business

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1 unit's financial exhibits based on what is achievable by the forward test year is
2 more appropriate.

3

4 **Corporate Memberships**

5 **Q43. What intervenor positions related to the Company's proposed recovery of**
6 **corporate membership expenses are you addressing?**

7 A43. There is one intervenor position I will address related to the Company's proposed
8 recovery of corporate membership expenses:

- 9
 - DAAO Witness Koeppel's recommendation to disallow a portion or all of
- 10 the Company's proposed corporate membership expenses

11

12 **Q44. Can you summarize DAAO Witness Koeppel's recommendation to disallow a**
13 **portion or all of the Company's proposed corporate membership expenses?**

14 A44. Yes. In his direct testimony, DAAO Witness Koeppel recommends that the
15 Commission "disallow recovery of a significant portion, if not all, of the company's
16 requested corporate membership expenses in this case." (page 51) DAAO Witness
17 Koeppel argues that the Company did not follow the Commission's guidance from
18 its December 1, 2023, Order in Case No. U-21297 that stated:

19

20 "DTE Electric shall provide in its next general rate case a detailed description
21 of how these organizations specifically impact/benefit customers as outlined by
22 the DAAOs, which will convey DTE Electric's roles and responsibilities in
23 advancing ratepayer interests through its participation in each organization."
24 (page 221)

25

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1 DAAO Witness Koeppel specifically addresses the Company's membership of the
2 Edison Electric Institute (EEI) and argues that "distinction between lobbying and
3 non-lobbying activities is often blurry and subjective and may not fully capture the
4 scope and influence of EEI's advocacy and outreach efforts" (page 58) and that
5 "[t]he Commission should also be concerned about its own conflicts of interest."
6 (page 59). He captures several areas where he believes the positions taken by EEI
7 are not in customers' best interests.

8

9 DAAO Witness Koeppel concludes by recommending the disallowance of EEI
10 membership dues in addition to process-oriented recommendations around the
11 examination of proposed membership dues and the Company's presentment of
12 customer benefits.

13

14 **Q45. Does the Company agree with DAAO Witness Koeppel's recommendation to**
15 **disallow a portion or all of the Company's proposed corporate membership**
16 **expenses?**

17 A45. No. To start, the Company disagrees that it did not follow the Commission's
18 guidance in its December 1 Order. In the current case, the Company updated
19 Exhibit A-27, Schedule Q1, to capture *specific* customer benefits related to each of
20 its corporate memberships.

21

22 As it relates to DAAO Witness Koeppel's assessment of EEI, the Company notes
23 that positions taken by industry organizations like EEI do not necessarily reflect the
24 positions of its member companies simply because those companies pay
25 membership dues. In addition, the fact that DAAO Witness Koeppel believes that

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1 EEI has taken positions that are not in the best interest of customers does not negate
2 the benefits of EEI membership⁷ or provide sufficient justification to disallow the
3 Company's proposed membership dues.

4

5 Finally, DTE Electric urges the Commission to consider the *reasonableness* of
6 DAAO Witness Koeppel's recommendations. DAAO Witness Koeppel suggests
7 the Commission should consider the "...lack of detail about what specific activities
8 are funded at what levels with DTE's contributions and lack any specific examples
9 or quantitative evidence of how these benefits have actually translated into
10 improved service quality, reliability, affordability, or other tangible outcomes for
11 customers." (page 62)

12

13 The Company does not have ready access to a detailed list of all activities
14 undertaken by the industry associations of which it is a member. Similarly, the
15 industry associations of which the Company is a member do not designate the
16 Company's membership dues for a particular purpose or purposes. As such, the
17 Company simply does not have the level of detail suggested by DAAO Witness
18 Koeppel. Attempting to compile such information (assuming industry associations
19 have it available) would be costly in terms of the Company's time and resources
20 required, and DAAO Witness Koeppel has not provided compelling evidence that
21 such an undertaking would result in conclusive evidence supporting his position.
22 These costs would ultimately be passed onto customers.

23

⁷ The Company highlights access to benchmarking, best practices, networking, and research as benefits of EEI membership (Exhibit A-27, Schedule Q1, Page 3)

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1 As such, the Company maintains its proposed recovery of corporate membership
2 dues, including the use of the Exhibit A-21, Schedule Q1 as presented in this case.

3 **Projected Test Year**

4 **Q46. What intervenor positions related to the Company's use of a forward test year**
5 **are you addressing?**

6 A46. There is one intervenor position I will address related to the Company's proposed
7 use of a forward test year:

- 8 • ABATE Witness Dauphinais' recommendation that the Commission reject
9 the use of a forward test year

10

11 **Q47. Can you summarize ABATE Witness Dauphinais' recommendation that the**
12 **Commission reject the use of a forward test year?**

13 A47. Yes. In his testimony ABATE Witness Dauphinais recommends that the
14 Commission reject the Company's use of a forward test year, asserting that the use
15 of a forward test year:

- 16 • "...has caused and continues to cause customers to experience rate increases
17 sooner because rates are being based on future projections". (page 6)
- 18 • "...has resulted in higher rates for customers than if rates were based on the
19 historical test year." (page 6)
- 20 • "...has allowed and continues to allow DTE to fill its projections with
21 proposed capital expenditures and expenses that either DTE has not
22 irrevocably committed to making or otherwise can avoid if it finds it
23 advantageous to do so to improve its realized rate of return for its
24 shareholders." (page 6)

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- 1 • “...greatly handicaps the Commission Staff and intervenors in reviewing
2 DTE’s rate filings to ensure the projected capital expenditures and expenses
3 are reasonable because they are not actual capital expenditures and expenses
4 reflected on DTE’s books, but rather projections developed over many
5 separate cost subaccounts and revenue categories.” (page 6)

6

7 Further, on page 7 of his direct testimony Witness Dauphinais offers a definition of
8 “known and measurable changes” by suggesting such changes to costs are
9 “inescapable and precisely identifiable in amount and timing.” He goes onto argue
10 that “[f]uture capital expenditures and projected expenses are often not inescapable,
11 not precisely identifiable in amount and timing, or both.”

12

13 If the Commission decides to allow DTE the use of a forward test year in this
14 proceeding, ABATE Witness Dauphinais recommends the following:

15

16 “First, I recommend the Commission, be much more vigilant and aggressive
17 with respect to ensuring the expenses and investments being projected by DTE
18 for its projected test year are truly expenses and investments that are necessary
19 to provide reliable electric service at lowest reasonable cost. The Commission
20 should also ensure that DTE is irrevocably committed to incur its projected
21 expenses and investments or otherwise cannot avoid them. Finally, the
22 Commission should ensure that DTE’s projected investments and expenses are
23 precisely quantified by DTE with respect to both amount and the specific
24 quarter in which DTE will incur these investments and expenses.” (page 11)

25

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1 **Q48. Does the Company agree with ABATE Witness Dauphinais' recommendation**
2 **that the Commission reject the use of a forward test year?**

3 A48. No. To start, the Company has utilized, and the Commission has approved, the
4 current projected test year methodology for all the Company's rate cases filed
5 dating as far back as 2008.

6
7 In addition, the Company disagrees with ABATE Witness Dauphinais' definition
8 of "known and measurable changes". The forward test year is a projection of the
9 expenditures that are likely to be made given the information known at the time of
10 the rate case filing. Some of these costs will not occur for more than 20 months
11 after the Company filed this case and are subject to factors outside of the
12 Company's control. The Company's witnesses in this case provide testimony and
13 other support for the known (i.e., likely to occur) and measurable (i.e., can be
14 estimated with reasonable accuracy) nature of its proposed costs.

15
16 Further, the Company believes ABATE Witness Dauphinais' assertions that the use
17 of a forward test year results in customers experiencing "rate increases sooner
18 because rates are being based on future projections" and "has resulted in higher
19 rates for customers than if rates were based on the historical test year" are
20 misleading. Under a forward test year, base rates are proposed for a future twelve-
21 month period and, once approved by the Commission, go into effect no earlier than
22 the start of that future period. As such, the implementation of new rates matches
23 the projected costs approved by the Commission. This matching of costs and rates
24 supports the timely recovery of costs and helps ensure the Company can continue

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1 investing in projects and programs that deliver benefits to customers, such as
2 improvements in reliability.

3
4 Withholding rate increases until after costs have incurred would create an
5 unreasonable and unjust mismatch between when costs are incurred and when they
6 are recovered from customers. This is otherwise known as “Regulatory Lag” and
7 would challenge the Company’s ability to execute capital investments and realize
8 reliability improvements and other benefits, such as supporting the transition to
9 cleaner generation.

10
11 As it pertains to ABATE Witness Dauphinais’ concerns related to the Commission
12 approving capital investment that the Company has not “irrevocably committed to
13 making”, the Company disagrees that an “irrevocable commitment” is needed for
14 the Commission to approve capital investments for recovery. As discussed above,
15 the forward test year is a projection of the expenditures that are likely to be made
16 given the information known at the time of the rate case filing. The Company’s
17 witnesses in this case support the reasonableness and prudence of these
18 investments, including the timing and estimated cost of investments.

19
20 The Company further highlights that in this case it has proposed an extension and
21 expansion of its Distribution IRM. The IRM ensures that the Company invests
22 authorized amounts for their intended purposes or returns recovered investment to
23 customers – an irrevocable commitment. This directly addresses ABATE Witness
24 Dauphinais’ concerns, and yet he opposes the expansion of the IRM elsewhere in
25 his direct testimony.

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2

Finally, the Company disagrees with ABATE Witness Dauphinais' assertion that the use of a forward test year "greatly handicaps the Commission Staff and intervenors in reviewing DTE's rate filings to ensure the projected capital expenditures and expenses are reasonable." The burden of proof within a rate case falls on the Company to prove the reasonableness and prudence of its proposed investments and operating expenses, and the Company notes the Commission's May 18, 2023, Order in Case No. U-18238 which adopted new rate case filing requirements. Commission Staff and intervenors can challenge the recovery of any of the Company's proposed investments, as many intervenors have done in this case. The suggestion that they are somehow handicapped is unfounded.

12

13 **Incentive Compensation and Historic Revenues**

14 **Q49. What intervenor positions related to the Company's incentive compensation**
15 **and historic revenues are you addressing?**

16 A49. There is one intervenor position I will address related to the linkage between
17 incentive cost recovery and historical revenues:

- 18 • ABATE Witness York's recommendation that a portion of the Company's
19 proposed incentive compensation be disallowed given purported historic
20 revenue sufficiencies

21

22 **Q50. Can you summarize ABATE Witness York's recommendation to tie incentive**
23 **compensation recovery to historic revenues?**

24 A50. Yes. In her direct testimony, ABATE Witness York recommends:

25

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1 “In light of the Company’s recent failure to meet its reliability goals, as well as
2 its track record of historic revenue sufficiency amounts, the incentive
3 compensation associated with achieving these distribution reliability metrics
4 should not be recovered from ratepayers.” (page 17)

5

6 **Q51. Does the Company agree with ABATE Witness York’s recommendation to tie**
7 **incentive compensation recovery to historic revenues?**

8 A51. No. The Company’s historical revenue is irrelevant to the Company’s proposed
9 recovery of incentive compensation. Like it has dating back to 2008, the Company
10 in this case uses a forward test year in which it projects costs, such as incentive
11 compensation, and proposes recovery of those costs. The Company’s projection of
12 incentive compensation costs that it is proposing for recovery is developed
13 independently from the Company’s overall revenue in historic years. Linking them
14 together as recommended by ABATE Witness York would be inappropriate as it
15 would suggest that the Company’s projected costs for a specific cost item is
16 somehow informed by the Company’s overall revenue position in previous years.
17 As such, ABATE Witness York’s recommendation should be rejected.

18

19 Company Witness Fix further addresses ABATE Witness York’s recommendation
20 that incentive compensation recovery should be contingent upon the Company
21 meeting reliability targets.

22

23 **Q52. Does this conclude your rebuttal testimony?**

24 A52. 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)
its rate schedules and rules governing the)
distribution and supply of electric energy, and)
for miscellaneous accounting authority.)

Case No. U-21534

REBUTTAL TESTIMONY

OF

MARGARET E. GUILLAUMIN

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MARGARET E. GUILLAUMIN

Line
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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Margaret E. Guillaumin (she/her/hers). My business address is One
4 Energy Plaza, Detroit MI, 48226. I am employed by DTE Electric Company (DTE
5 Electric or Company) as Plant Director in the Energy Supply organization.

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to correct errors and rebut unjustified
14 recommendations for disallowances of capital projects as recommended by
15 multiple witnesses that provided direct testimony in the instant case. These
16 witnesses include:

- 17 • Attorney General (AG) Witness Coppola;
- 18 • Association of Businesses Advocating Tariff Equity (ABATE) Witness
- 19 York;
- 20 • Michigan Public Service Commission (MPSC) Staff (Staff) Witnesses
- 21 Kindschy and DeCooman.

22

23 I will also address Great Lakes Renewable Energy Association (GLREA) Witness
24 Richter's request for a battery energy storage system (BESS) siting analysis.

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1 The absence of a discussion of other matters in my rebuttal testimony should not
2 be taken as an indication that I agree with all other aspects of any intervenor's
3 testimony.

4

5 **Q4. Are you sponsoring any exhibits in this proceeding?**

6 A4. Yes. I am sponsoring the following exhibits:

7 Exhibit Schedule Description

8 A-34 Y1 BWEC Conference Room Building Discovery Responses

9 STDE-2.5, STDE-3.6b-d, STDE-10.1a-c

10 A-34 Y2 Power Generation 2023-2024 Non-Routine Capital

11 Expenditure Projections and Actuals from Discovery

12 Responses STDE-2.1a and STDE-2.1b

13

14 **Q5. Were these exhibits prepared by you, under your direction, or are you**
15 **otherwise familiar with their contents as part of your job responsibilities?**

16 A5. Yes.

17

18 **Q6. How is your rebuttal testimony organized?**

19 A6. My rebuttal testimony consists of the following ten (10) parts:

20 Part I The Company's routine capital maintenance projections for Belle River
21 and Greenwood Power Plant are based on specific approved and justified
22 projects. This is in contrast to the AG witness's use of multi-year
23 historical averages of total project spending levels to support his
24 generalized disallowance recommendations

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- 1 Part II The Blue Water Energy Center (BWEC) Conference Room Building
2 project is cost-effective and adequately supported
- 3 Part III The Company's newly-available actual capital expenditure data for
4 November 2023 through April 2024 does not warrant a disallowance as
5 proposed by Staff
- 6 Part IV Staff's assignment of cost estimate class accuracy range factors to the
7 Company's routine capital projects is inappropriate in its application and
8 is driving flawed disallowance recommendations
- 9 Part V The Company's black start projects are justified, and the Company took
10 balanced, reasonable, and necessary steps to be transparent while
11 protecting security sensitive information in this instant case
- 12 Part VI Staff's recommended reductions on Trenton Channel BESS non-contract
13 spend projections are not well-supported
- 14 Part VII ABATE's proposed disallowance related to River Rouge
15 Decommissioning based on minor paperwork differences is unwarranted
- 16 Part XIII The Company appropriately calculated overheads on the Slocum Battery
17 Pilot
- 18 Part IX The Trenton Channel Seawall project is worthy of recovery in the instant
19 case
- 20 Part X GLREA's request for an electrical distribution system-connected BESS
21 analysis is unnecessary

Line
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1 **Part I – The Company’s routine capital maintenance projections for Belle River and**
2 **Greenwood Power Plant are based on specific approved and justified projects. This**
3 **is in contrast to the AG witness’s use of multi-year historical averages of total**
4 **project spending levels to support his generalized disallowance recommendations**

5
6 **Q7. What does AG Witness Coppola recommend with respect to the Company’s**
7 **projected routine capital expenditures for its Belle River and Greenwood**
8 **Power Plants?**

9 A7. Witness Coppola recommends removal of \$30.1 million¹ of projected 2024-2025
10 routine capital expenditures. His \$30.1 million recommended adjustment is
11 comprised of \$13.3 million of 2024 capital expenditures at Belle River Power Plant
12 and \$16.8 million total in 2024-2025 capital expenditures at Greenwood Power
13 Plant.

14
15 **Q8. What is the basis of Witness Coppola’s proposed removal adjustment of Belle**
16 **River Power Plant and Greenwood Power Plant routine capital expenditures?**

17 A8. Witness Coppola compares the Company’s 2024 and 2025 total projected routine
18 capital expenditures for the Belle River and Greenwood Power Plants against an
19 average of the last three years of actual project expenditures for these plants. He
20 then applies inflation to his historic average and indicates project funding levels
21 above the inflated historic averages should be removed from the forecasted capital
22 expenditures². Witness Coppola makes these disallowance recommendations
23 without any evaluation of the Company’s justified and internally approved projects

¹ Witness Coppola DT, page 36, lines 13-14 (\$8.585m in 2024; \$8.223m in 2025) and page 37, lines 1-2 (\$13.270m in 2024).

² Witness Coppola DT, page 36, lines 9-14 and page 36, line 15 through page 37, line 2.

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1 for these two power plants. He apparently determines that historical plant project
2 funding levels should set a limit for future funding levels despite equipment
3 condition, changing circumstances, and continuing electrical system reliance on
4 these power plants.

5

6 **Q9. How do you respond to Witness Coppola's use of historical spending averages**
7 **to establish the next two years of routine capital maintenance at the Belle River**
8 **and Greenwood Power Plants?**

9 A9. The Company disagrees with Witness Coppola's approach. DTE Electric does not
10 use historical spending averages to establish the next two years of routine capital
11 maintenance at its power plants. The level of capital project work needed, justified,
12 planned, and approved is required to maintain safe, reliable, and environmentally
13 compliant future plant operations. Using historical averages ignores the specific
14 work necessary, including increased project work expected due to planned outage
15 schedules. These projects include the 2024 and 2025 capital projects listed on
16 Exhibit A-12, Schedule B5.1, pages 6 and 7 for Belle River and Greenwood Power
17 Plant that exceed \$1 million.

18

19 **Q10. What is requiring the Belle River and Greenwood Power Plants' planned**
20 **routine capital maintenance expenditures to exceed the 2021-2023 average**
21 **amount?**

22 A10. In the 2021-2023 timeframe utilized by Witness Coppola to establish his average
23 historical spending levels, Belle River Power Plant only had one major maintenance
24 outage and Greenwood Power Plant had a partial maintenance outage. For 2024
25 and 2025 in the instant case, two major maintenance outages are planned for Belle

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1 River Power Plant and one full major maintenance outage for Greenwood Energy
2 Center. The historical spending level identified by Witness Coppola does not
3 support execution of the identified, justified, and approved capital projects planned
4 for completion during these outages in 2024 and 2025.

5

6 **Q11. Why are planned outage schedules an important consideration for projected**
7 **routine capital maintenance?**

8 A11. The Company's steam generation units are typically taken offline at least once
9 every 3-5 years for several months in order to perform major maintenance. During
10 these planned major maintenance outages, large capital projects are completed to
11 keep the units running safely, reliably, efficiently, and environmentally compliant
12 until the next major maintenance. This results in variability in annual spend levels,
13 with some years being much higher than others, based on the amount and
14 complexity of required power plant work, not by calendar year or funding utilized
15 in past years.

16

17 **Q12. Are there other reasons that can cause routine capital expenditures to be**
18 **higher in one year compared to an average historical annual value?**

19 A12. Every major maintenance outage includes differing work activities and supportive
20 capital projects. Project scope and required funding levels can increase greatly
21 when major work on the turbine-generator and/or boiler key components is
22 required. For example, the Company is replacing the low pressure (LP) turbines
23 on Belle River Unit 2 in 2024 and Greenwood Unit 1 in 2025 due to industry-wide
24 concerns with stress corrosion cracking as further discussed in my revised direct
25 testimony, pages 88-89 and 102. This turbine maintenance is routine in nature but

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1 infrequent as evidenced by this being the first time the LP turbines have been
2 replaced in the history of these plants. The LP turbine rotors were original
3 equipment and installed approximately 40 years ago. In total, each turbine
4 replacement project exceeds \$20 million. Infrequent but routine in nature, large
5 capital maintenance projects, such as the replacement of the LP turbines, lead to
6 lumpy annual capital expenditure levels. Witness Coppola fails to acknowledge
7 this expected variability when he recommends limiting future capital project
8 funding approvals based on the funding required during the 2021-2023 period.

9

10 **Q13. What should the Commission find with respect to Witness Coppola's**
11 **recommendation to remove portions of the planned capital routine**
12 **maintenance at the Belle River and Greenwood Power Plants simply based on**
13 **historical average spend?**

14 A13. The Commission should find the Company's use of specific project plans is
15 appropriate and required. Witness Coppola's use of historical averages to limit
16 projected routine capital expenditures for 2024 and 2025 is not prudent or logical
17 and his recommended \$30.1 million disallowance, which includes no engineering
18 analysis, should carry no weight.

19

20 **Part II – The Blue Water Energy Center (BWEC) Conference Room Building**
21 **project is cost-effective and adequately supported**

22

23 **Q14. What does ABATE Witness York recommend with respect to the Company's**
24 **projected capital expenditures for the BWEC Conference Room Building**
25 **project?**

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1 A14. Witness York recommends removal of \$3.3 million of projected 2024 capital
2 expenditures for the BWEC Conference Room Building project³.

3

4 **Q15. What is the basis of Witness York's proposed disallowance of BWEC**
5 **Conference Room Building project capital expenditures?**

6 A15. Witness York argues the Company has not adequately justified the cost or necessity
7 of the new conference room building and questions why adequate office space to
8 support site workforce during routine and major maintenance activities was not
9 included in the original design of the site⁴.

10

11 **Q16. Has the Company provided additional justification for the necessity of the**
12 **BWEC conference room building after its need was previously questioned?**

13 A16. Yes. In response to the December 1, 2023, Commission Order from the last rate
14 case, Case No. U-21297, further explanation was provided for the project in my
15 revised direct testimony, pages 117-118 in the instant case. This explanation
16 describes the need for additional workspaces during routine and major maintenance
17 activities because a high number of support personnel are onsite during this time.
18 All Company power plants have either constructed or repurposed available space
19 over the years to create large meeting spaces to accommodate workforce surges
20 during routine and major outages or construction activities. In addition, it was
21 explained that this building was not required during initial construction of the plant
22 because short-term rental trailers were utilized by the project construction firm,
23 Kiewit, for the purpose of hosting and onboarding the large workforce during
24 project construction.

³ Witness York DT, page 25, line 18 through page 26, line 3.

⁴ Witness York DT, page 25, line 20 through page 26 line 3.

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1

2 **Q17. Has the Company provided justification supporting the cost-effectiveness of**
3 **adding the BWEC conference room building?**

4 A17. Yes. Exhibit A-34, Schedule Y1 includes several discovery responses related to
5 the BWEC Conference Room building. Included in the responses is an analysis of
6 the BWEC Conference Room Building project versus other options including
7 purchasing and renting trailers. This analysis indicates that the new conference
8 room project will save the Company \$10+ million over the life of the plant as
9 compared to purchasing and renting trailers to support plant needs.

10

11 **Q18. What should the Commission find with respect to Witness York's**
12 **recommendation to remove projected 2024 capital expenditures for the**
13 **BWEC Conference Room Building project?**

14 A18. The Commission should find the Company properly supported the cost
15 effectiveness and necessity of the BWEC Conference Room Building project in
16 revised direct testimony and discovery responses in the instant case. Witness
17 York's recommendation to disallow \$3.3 million of project expenditures associated
18 with the BWEC Conference Room Building should be rejected.

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**Part III – The Company’s newly-available actual capital expenditure data for
November 2023 through April 2024 does not warrant a disallowance as proposed by
Staff**

Q19. Based on monthly actual capital expenditures that post-date the data relied upon to develop the instant case, what do Staff Witnesses Kindschy and DeCooman recommend?

A19. For routine capital projects, Staff Witness Kindschy recommends a \$21.3 million reduction in capital project expenditures based on the difference between November 2023 through April 2024 actual expenditures and the projected amounts included in my exhibits⁵.

Similarly, for non-routine capital projects, Staff Witnesses Kindschy and DeCooman collectively recommend a \$5.1 million reduction to capital expenditures. The \$5.1 million reduction includes Witness Kindschy’s review of lines 1-18 of Exhibit A-12, Schedule B5.1, page 2, in which she identifies \$0.6 million of reduction for 2023 expenditures and \$3.1 million of reduction for 2024 expenditures⁶. Also included in the \$5.1 million is Witness DeCooman’s recommended \$1.4 million reduction to 2023 expenditures on the Company’s blackstart projects lines 37-39 of Exhibit A-12, Schedule B5.1, page 2⁷.

Q20. Does the fact that there is a difference between the *monthly* forecast for capital spend levels in exhibits compared to the actual spending levels for November

⁵ Witness Kindschy DT, page 7, line 14 through page 8, line 2.

⁶ Witness Kindschy DT, page 6, lines 16-19.

⁷ Witness DeCooman DT, page 8, lines 19-21.

Line
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1 **2023 through April 2024 justify Witness Kindschy's and Witness DeCooman's**
2 **disallowance recommendations?**

3 A20. No. The variance between exhibit and actual project spends for these short few
4 months is not a proper metric for measuring the performance of project execution,
5 nor an adequate projection of final project results. Those referenced differences
6 evidence nothing with regard to reasonableness and prudence of the projects.
7 Capital projects are managed on a total beginning-to-end basis with monthly
8 estimates developed to track general project evolution and annual total budget
9 targets. Monthly work scope plans and associated spend are developed at the start
10 of the project and updated periodically throughout the project timeline. There can
11 be monthly timing variances within the project execution that shift spend between
12 months across the duration of the project. Timing variances mean work has
13 completed or will be completed sooner or later than initially forecasted. The
14 Company expects the portfolio of projects to meet the overall projected spend as
15 represented in this instant case.

16

17 **Q21. How are capital projects measured?**

18 A21. Capital projects are measured against the total project scope, the planned schedule,
19 and the total funding level requested in the project approval documents. The end
20 result of scope and cost are important, not the day-by-day or month-by-month
21 journey taken to reach project completion.

22

23 **Q22. Following Witness Kindschy's and Witness DeCooman's analyses of monthly**
24 **expenditure variance, what would one find if all the non-routine capital**
25 **project forecasts included in Exhibit A-12, Schedule B5.1, page 2 were**

Line
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1 **compared to the actual expenditures for the period November 2023 through**
2 **April 2024, instead of the partial subset of line items Witness Kindschy and**
3 **Witness DeCooman chose?**

4 A22. The Company's non-routine Power Generation expenditures for all the non-routine
5 projects for November 2023 through April 2024 are \$123.6 million, which exceeds
6 the \$109.3 million projected in Exhibit A-12, Schedule B5.1, page 2 for those
7 months in the instant case. Please refer to the rebuttal Exhibit A-34, Schedule Y2
8 for additional details. Based on following Witness Kindschy's and Witness
9 DeCooman's approach, those monthly expenditure variances alone would justify a
10 positive adjustment, with the Company's non-routine capital expenditures needing
11 to be increased by \$14.4 million in the instant case.

12

13 **Q23. What should the Commission find with respect to Witness Kindschy's and**
14 **Witness DeCooman's use of monthly capital spend variances to justify \$26.4**
15 **million⁸ of reductions to the Company's projects?**

16 A23. The recommendations to disallow project funding based on recent actual monthly
17 project spends should be disregarded. Just because a variance between forecast and
18 actual data can be found on a recent and short-term basis does not mean that the
19 projects are over-funded or are not being executed properly. The total result of a
20 project is the proper basis for scrutiny, not the day-by-day or month-by-month
21 journey of project planning and execution. Additionally, selection of only a subset
22 of projects in which the total actual spend is lower than the forecast is not a balanced
23 approach and should therefore be rejected.

⁸ The \$26.4 million of reductions is comprised of \$21.3 million of routine capital expenditures and \$5.1 million of non-routine capital expenditures.

Line
No.

1 **Part IV – Staff’s assignment of cost estimate class accuracy range factors to the**
2 **Company’s routine capital projects is inappropriate in its application and is driving**
3 **flawed disallowance recommendations**
4

5 **Q24. What is the Association for the Advancement of Cost Engineering (AACE)**
6 **International Cost Estimate Classification System and how has Staff Witness**
7 **Kindschy utilized it in the instant case?**

8 A24. The International Cost Estimate Classification System focuses primarily on the
9 level of project definition with secondary consideration on the purpose of the
10 estimate, typical estimating method, expected accuracy range, and the expended
11 effort of the estimate compared to the final project estimate. The AACE Cost
12 Estimate Classification System is referenced by Staff Witness Kindschy and
13 utilized as her stated source for recommending a 15% capital project funding
14 disallowance for 2024 Power Generation projects and a 20% capital project funding
15 disallowance for 2025 Power Generation projects⁹.
16

17 **Q25. Why does Witness Kindschy recommend disallowances for routine**
18 **maintenance projects, including the use of different funding disallowance rates**
19 **for 2024 work versus 2025 work on the same project?**

20 A25. Witness Kindschy indicates the later year (2025) work is mostly at an earlier stage
21 of development, is further in the future, and should therefore carry a higher
22 disallowance factor when compared to nearer term (2024) work¹⁰.

⁹ Witness Kindschy DT, pages 8-9. Witness Kindschy reduces the Company’s routine maintenance capital projects greater than \$1 million that are in a PAT-0 or PAT-1 state.

¹⁰ Witness Kindschy DT, page 9, lines 1-3.

Line
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1 **Q26. How does AACE address the typical variation in actual costs as compared to**
2 **what Witness Kindschy has done?**

3 A26. The AACE guidelines clearly state, as can be found on Staff Exhibit S-16.3, page
4 3 of 10, Note A: “The state of process technology and availability of applicable
5 reference cost data affect the range markedly. The +/- value represents typical
6 variation of actual costs from the cost estimate *after application of contingency ...*
7 *for the given scope* (emphasis added).” Witness Kindschy has applied her
8 disallowance factors to funding requests made by the Company that have already
9 been “de-risked” because all contingency funding has been excluded from the
10 amounts being requested in the instant case.

11

12 **Q27. Do you have any concerns regarding the application of the AACE cost estimate**
13 **classification system by Witness Kindschy?**

14 A27. Witness Kindschy’s application of the AACE cost estimate classification is flawed
15 because it applies her 15% and 20% reduction factors without recognizing or
16 acknowledging that the Company’s projects do not include requests for project
17 contingency funding. She utilizes the 15% and 20% factors, indicates she has
18 followed the AACE guidelines, then incorrectly applies the adjustments to the
19 Company’s projected capital expenditures without adding in project contingency
20 as directed in the AACE guidelines.

21

22 **Q28. What is the impact of applying reduction factors to projections without adding**
23 **contingency?**

24 A28. Applying reduction factors to projections that exclude contingency inflates Witness
25 Kindschy’s disallowance recommendations. Below is a simplified example on a

Line
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single project that illustrates the calculation error behind Witness Kindschy's recommendations.

Table 1 AACE Method versus Witness Kindschy's Method

Method	Project Cost	Reduction Factor	Reduction	Remaining
AACE Method	\$4 + \$1 of contingency	20%	$\$5 \times -20\% =$ -\$1	$\$5 - \$1 =$ \$4
Kindschy Method	\$4 + \$0 of contingency	20%	$\$4 \times -20\% =$ -\$0.8	$\$4 - \$0.8 =$ \$3.2

As shown in Table 1 above, proper application of the AACE method and applying a 20% reduction factor results in an amount remaining (\$4) near the base project spend excluding contingency (\$4). However, applying Witness Kindschy's method of excluding contingency in the project cost, which is not consistent with AACE cost estimate standards, results in an amount remaining (\$3.2) well less than the base project spend excluding contingency (\$4). In other words, Witness Kindschy's method inappropriately reduces projected capital expenditures more than the AACE method would have one do.

Q29. Why has this error not been previously recognized?

A29. To the best of my knowledge, the MPSC Staff has not previously utilized the AACE methodology to make any specific Energy Supply project funding adjustments in a Company rate case.

Line
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1 **Q30. How do you respond to Witness Kindschy's claim that a short-term variance**
2 **between a forecast and actual expenditure supports the use of specific**
3 **accuracy range adjustment factors to project estimates as the basis to**
4 **recommend project disallowances¹¹?**

5 A30. A variation between actual and forecasted spend over a 6-month period is not
6 indicative of total performance over the entire project duration. As discussed
7 above, capital projects are managed on a total beginning-to-end basis with monthly
8 estimates only developed to track general project evolution and annual total budget
9 targets. A project being underspent (actual expenditures were less than a forecast)
10 in the past does not justify reductions to future projections. On the contrary, if
11 project spending is lower than expected due to a timing variance, the future
12 spending will likely be higher than the original monthly forecast as a result of
13 spending milestones shifting to the future.

14

15 **Q31. What should the Commission find with respect to Witness Kindschy's**
16 **application of AACE cost estimate standards to the Company's routine capital**
17 **expenditures?**

18 A31. The Commission should find Witness Kindschy misapplied her 15% and 20%
19 reductions by using the Company's projections that already exclude contingency as
20 is the Company's practice, which is inconsistent with the AACE instructions
21 provided in her own exhibit. Also, since Witness Kindschy relied, at least in part,
22 on timing variances to justify further reductions in projected routine capital projects
23 that are at a PAT0 or PAT1 as described above in my testimony, Witness
24 Kindschy's proposed reductions for the 7-month period ending December 31, 2024

¹¹ Witness Kindschy DT, page 9, lines 4-7.

Line
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1 and 12-month period ending December 31, 2025 of \$39.1 million¹² should be
2 dismissed.

3

4 **Part V – The Company’s black start projects are justified, and the Company took**
5 **balanced, reasonable, and necessary steps to be transparent while protecting**
6 **security sensitive information in this instant case**

7

8 **Q32. What does ABATE Witness York recommend with respect to the Company’s**
9 **projected test year capital expenditures for the black start projects?**

10 A32. Witness York recommends removal of \$34.4 million of 2023-2025 projected
11 capital expenditures for five black start projects¹³. The \$34.4 million is comprised
12 of \$12.6 million of 2023-2024 expenditures on Project 10570 & 20255 (Exhibit A-
13 12, Schedule B5.1 page 2, line 37), \$8.1 million of 2023-2024 expenditures on
14 Project 17611 (Exhibit A-12, Schedule B5.1 page 2, line 38), \$4.4 million of 2023-
15 2024 expenditures on Project 18320 (Exhibit A-12, Schedule B5.1 page 2, line 39),
16 \$2.8 million of 2025 expenditures on Project 19737 (Exhibit A-12, Schedule B5.1
17 page 7, line 225 - Blackstart Peaker Unit 2 Starting System), and \$6.4 million of
18 2025 expenditures on Project 18090 (Exhibit A-12, Schedule B5.1 page 7, line 231
19 - Blackstart Unit Major Overhaul).

20

21 **Q33. What is the basis of Witness York’s proposed removal of black start project**
22 **capital expenditures?**

23 A33. Witness York states that because the supporting Project Management Process
24 (PMP) documents for the projects are redacted, the parties cannot independently

¹² Witness Kindschy DT, page 9, lines 7-11.

¹³ Witness York DT, page 19, Table JAY-3 (lines 3-7).

Line
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1 review and assess the scope of this project, the project timeliness, or any revisions
2 that have occurred¹⁴.

3

4 **Q34. Did the Commission address the issue of redacted black start project details**
5 **in the last DTE Electric rate case, Case No. U-21297?**

6 A34. Yes. In the Case No. U-21297 Order dated December 1, 2023, the Commission
7 found inclusion of the majority of expenditures associated with the black start
8 projects in rate base to be appropriate¹⁵. After considering the project evidence the
9 Company provided and the International Transmission Company's (ITC¹⁶) support
10 for both the absolute necessity of black start units and the need to keep the project
11 information on a highly confidential basis, the Commission agreed with the
12 Company's position and did not adopt the disallowances recommended by ABATE
13 and the AG which were based on the Company not disclosing detailed project
14 information.

15

16 **Q35. What should the Commission find with respect to Witness York's proposed**
17 **disallowance of black start project capital expenditures?**

18 A35. The Commission should find the Company properly protected the security sensitive
19 information in the instant case, just as it did in Case No. U-21297. Witness York's
20 direct testimony essentially reiterates arguments that were already considered and
21 rejected in the Company's previous rate case and her \$34.4 million disallowance
22 recommendation should be rejected.

¹⁴ Witness York DT, pages 22-25.

¹⁵ Case No. U-21297 Order dated December 1, 2023, pages 40-44.

¹⁶ ITC is the owner of the grid blackout restoration plan and tightly controls information on black start assets (see ITC Witness Chindhade's DT, pages 3-5).

Line
No.

1 **Q36. What does Staff Witness DeCooman recommend with respect to the**
2 **Company's bridge period capital expenditures for the black start projects?**

3 A36. Witness DeCooman recommends partial disallowance of \$1.4 million and \$1.2
4 million in capital expenditures in 2023 and 2024¹⁷, respectively. This
5 recommended disallowance is comprised of \$0.3 million of capital expenditures for
6 Project #10570 & 20255 in 2023, \$0.3 million of capital expenditures for Project
7 #10570 & 20255 in 2024, \$0.1 million of capital expenditures for Project #17611
8 in 2023, \$0.9 million of capital expenditures for Project #17611 in 2024, \$1.0
9 million of capital expenditures for Project #18320 in 2023, and \$0.1 million of
10 capital expenditures for Project #18320 in 2024¹⁸.

11

12 **Q37. What is the basis of Witness DeCooman's proposed partial disallowance of**
13 **bridge period black start project capital expenditures?**

14 A37. For 2023, Witness DeCooman bases his proposed adjustments on variances
15 between actual project capital expenditures and the amounts projected in Exhibit
16 A-12, Schedule B5.1, page 2. This adjustment related to 2023 capital expenditures
17 is addressed in Part III of my rebuttal testimony.

18

19 For 2024, Witness DeCooman calculates the 2-year percentage difference between
20 the amounts forecasted in the Company's last case, Case No. U-21297, and the
21 actual capital expenditures incurred for each black start project. Based on an
22 average 14% difference between the amounts forecasted and the actual capital
23 expenditures, he reduces the Company's 2024 projections by 14%¹⁹.

¹⁷ Witness DeCooman DT, page 10, lines 5-7.

¹⁸ Witness DeCooman DT, page 9, lines 7-8.

¹⁹ Witness DeCooman DT, page 8, line 1 through page 9, line 4.

Line
No.

1 **Q38. How do you respond to Witness DeCooman’s recommendation to reduce the**
2 **black start project capital expenditures in 2024 based on the percentage**
3 **variance between what was requested in the last rate case and the actual**
4 **capital expenditures?**

5 A38. I disagree. I do not find it reasonable to assume that because a group of projects in
6 total were underspent (actuals were less than a forecast) in the past, future
7 projections for those projects should be reduced. On the contrary, if certain project
8 spending is lower than expected in a given year, the future year spending may be
9 higher than the original forecast as a result of spending milestones shifting to future
10 years. Additionally, Witness DeCooman does not consistently apply this spend
11 forecast adjustment logic to projects which saw higher capital expenditures than
12 forecasted which would otherwise adjust such projects’ spending forecasts higher.

13

14 **Q39. What should the Commission find with respect to Witness DeCooman’s**
15 **proposed partial disallowance of black start project capital expenditures?**

16 A39. The Commission should find the fact that a project or group of projects underspent
17 during a period compared to a forecast does not demonstrate future project
18 expenditures should be reduced and therefore Witness DeCooman’s \$1.2 million
19 2024 disallowance recommendation should be rejected.

20

21 **Part VI – Staff’s recommended reductions on Trenton Channel BESS non-contract**
22 **spend projections are not well-supported**

23

24 **Q40. What does Staff Witness DeCooman recommend with respect to the Trenton**
25 **Channel BESS non-contract spend?**

Line
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1 A40. Witness DeCooman recommends removing \$9.9 million of 2024 and 2025 capital
2 expenditures from the Company's projections based on uncertainty in the estimates
3 for work that does not have established contracts²⁰.
4

5 **Q41. How did Witness DeCooman calculate a \$9.9 million reduction?**

6 A41. Witness DeCooman's calculation can be found in his Exhibit S-10.6. In that
7 exhibit, he subtotals certain lines of expenditures in 2024 and 2025. His
8 recommended removal includes 10% of the 2024 subtotaled amount and 20% of
9 the 2025 subtotaled amount.
10

11 **Q42. What is the basis of the specific 10% and 20% multipliers utilized in Witness**
12 **DeCooman's removal adjustment?**

13 A42. Witness DeCooman does not explain how he arrived at the specific 10% and 20%
14 reductions for 2024 and 2025, respectively.
15

16 **Q43. Do you have any observations concerning Witness DeCooman's calculations?**

17 A43. It appears Witness DeCooman was attempting to calculate expenditures that are not
18 associated with an existing contract. However, in Witness DeCooman's calculation
19 of non-contracted work in Exhibit S-10.6 (the row below row 11), he inconsistently
20 includes line 8 (owner's engineer and expert support) in his calculation, even
21 though that line item is listed as being subject to a contract. Witness DeCooman
22 also includes all the funding shown in lines 9 and 10 (project overheads and
23 AFUDC), even though the majority of the expenditures on these lines are dictated
24 by direct spend for which contracts exist. In short, Witness DeCooman's

²⁰ Witness DeCooman DT, page 17, line 11 through page 18, line 4.

Line
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1 calculation of non-contract spend, which he relies on to develop his capital
2 reduction recommendation, inconsistently includes spend associated with
3 contracts.

4

5 **Q44. What should the Commission find with respect to Witness DeCooman's partial**
6 **removal of Trenton Channel BESS non-contract spend projections?**

7 A44. The Commission should find Witness DeCooman's adjustment factors lack specific
8 explanation and justification. Additionally, inconsistencies are included in the
9 calculation. Accordingly, his recommendation to remove \$9.9 million from the
10 Trenton Channel BESS projection should be dismissed.

11

12 **Part VII – ABATE's proposed disallowance related to River Rouge**

13 **Decommissioning based on minor paperwork differences is unwarranted**

14

15 **Q45. What is the basis of ABATE Witness York recommending a partial reduction**
16 **for 2024 expenditures on the River Rouge Decommissioning project (Exhibit**
17 **A-12, Schedule B5.1, page 2, line 25)?**

18 A45. In reviewing the Company's project documentation, Witness York identified an
19 annual difference for 2024 between the capital expenditures included in my exhibits
20 and the Company's CARF retiming form.²¹ Exhibit A-12, Schedule B5.1, page 2,
21 line 25 projects \$12.8 million of expenditures in 2024. The CARF retiming form,
22 included as Witness York's Exhibit AB-2, page 3, shows \$8.4 million in 2024.
23 Based on this difference, Witness York recommends disallowing the \$4.4 million

²¹ Witness York DT, page 21 line 9 through page 22 line 7 and York DT page 19, Table JAY-3.

Line
No.

1 difference between the annual amount in the exhibit and the annual amount in the
2 CARF retiming form.

3

4 **Q46. How do you respond to Witness York's recommended disallowance for the**
5 **River Rouge Decommissioning project?**

6 A46. A closer look at the CARF retiming form (Witness York's Exhibit AB-2, page 3)
7 shows a total authorized funding amount of \$94.9 million for the River Rouge
8 Decommissioning project. This includes \$48.3 million of projected expenditures
9 in 2025 associated with continuing the demolition of the now-retired power plant.
10 As discussed further on page 38 of my revised direct testimony, the Company will
11 address and request the remaining decommissioning expenditures in a future rate
12 case. There is more than enough funding authorized and anticipated for this long-
13 term project to cover the \$4.4 million difference Witness York identifies.

14

15 **Q47. What should the Commission find with respect to Witness York's**
16 **recommendation related to a partial removal of River Rouge**
17 **Decommissioning expenditures?**

18 A47. The Commission should find the Company's approval documents have sufficient
19 approved funding to cover the 2024 difference in paperwork that Witness York
20 points out for this long-term project. Accordingly, Witness York's \$4.4 million
21 disallowance recommendation should be rejected.

Line
No.

1 **Part XIII – The Company appropriately calculated overheads on the Slocum**

2 **Battery Pilot**

3

4 **Q48. What is the basis of Staff Witness DeCooman's recommendation to reduce the**
5 **projected capital expenditures for the Slocum Battery Pilot project (Exhibit**
6 **A-12, Schedule B5.1, page 2, line 40) by \$2.2 million²²?**

7 A48. Witness DeCooman recommends reducing the projected capital expenditures for
8 the Slocum Pilot by the amounts the overheads increased from the Company's
9 previous rate case, Case No. U-21297, because he claims the Company did not
10 adequately support the nature of this cost increase²³.

11

12 **Q49. How did the Company explain the cost increase in overheads from the last case**
13 **to the instant case?**

14 A49. As shown in Witness DeCooman's Exhibit S-10.3, page 5, the Company explained
15 the increase in overheads was driven by increases in material and labor costs on
16 which the indirect overheads are calculated and applied.

17

18 **Q50. How are overheads allocated to capital projects?**

19 A50. The allocation of overheads to the Slocum Battery pilot, as with all other Company
20 capital projects, is done on a monthly basis. Overhead costs are charged to all
21 capital projects based on actual direct costs. Direct costs include costs like labor,
22 material, and contract labor that are charged directly to the projects.

23

24 **Q51. How did the overhead charges change from the last case to the instant case?**

²² Witness DeCooman DT, page 12, lines 16-17.

²³ Witness DeCooman DT, page 13, lines 5-6.

Line
No.

1 A51. In Case No. U-21297, the Slocum Battery pilot projected cost was \$34.7 million.
2 This was comprised of \$30.9 million of direct costs and \$4.8 million of indirect
3 (overhead) costs as shown in Witness DeCooman's direct testimony, page 12.
4 Overhead costs represented 14% (\$4.8 million / \$34.7 million) of the total project
5 in Case No. U-21297.

6

7 In the instant case, the Slocum Battery pilot is projected to be \$44.7 million as
8 shown in Witness DeCooman's direct testimony, page 12. This is comprised of
9 \$37.8 million of direct costs and \$6.9 million of indirect (overhead) costs.
10 Overhead costs represent 15% (\$6.9 million / \$44.7 million) of the total project in
11 the instant case.

12

13 As shown above, the overhead costs, as a percentage of the total project, have
14 remained consistent between the previous case and the instant case. The increase
15 in indirect overhead costs between the two cases is a result of increased direct
16 project costs.

17

18 **Q52. What should the Commission find with respect to Witness DeCooman's**
19 **recommendation to exclude the difference in Slocum Battery Pilot overheads**
20 **from the last case to the instant case?**

21 A52. The Commission should find the Company appropriately estimated the indirect
22 project overheads in the instant case for the Slocum Battery Pilot. Witness
23 DeCooman's \$2.2 million reduction recommendation should be rejected.

24

Line
No.

1 **Part IX – The Trenton Channel Seawall project is worthy of recovery in the instant**
2 **case**

3
4 **Q53. What is the basis of ABATE Witness York recommending full disallowance of**
5 **the Trenton Channel Seawall project (Exhibit A-12, Schedule B5.1, page 2, line**
6 **28)?**

7 A53. Witness York recommends excluding the entire Trenton Channel Seawall project
8 (\$10.9 million²⁴) from rates at this time because the Company provided an
9 Appropriation Request document that does not support the level of expenditures
10 shown in the Company's Exhibit A-12, Schedule B5.1.²⁵

11

12 **Q54. What is prompting the Company to complete the Trenton Channel Seawall**
13 **project?**

14 A54. The project is required to restore the seawall's integrity at the Trenton Channel
15 Power Plant site. The existing infrastructure is at its end of life and must be
16 replaced to ensure the stability of the land surrounding the riverfront. Additionally,
17 the City of Trenton stipulated the Company develop a pedestrian greenway path
18 that provides access to the Detroit River riverfront as part of the approved
19 demolition permit for the Trenton Channel Power Plant. Trenton Channel Power
20 Plant was recently demolished in anticipation of construction of the new Trenton
21 Channel BESS.

²⁴ Witness York DT, page 20, line 16 through page 21, line 1.

²⁵ Witness York DT, page 19, Table JAY-3 line 1 and York DT, page 21, lines 3-8.

Line
No.

1 **Q55. How is the Trenton Channel Seawall Project progressing?**

2 A55. Thus far, the Company has spent over \$500 thousand to support engineering and
3 design work. The full project is scheduled to be completed in 2025 and is
4 progressing as planned.
5

6 **Q56. How do you respond to Witness York's statement that the Company's**
7 **appropriation request does not support the level of expenditures in Exhibit A-**
8 **12, Schedule B5.1²⁶?**

9 A56. Witness York's Exhibit AB-2 page 1 shows a signed appropriations request for \$1.1
10 million for the Trenton Channel Seawall project. This funding supports the design
11 and engineering work for the project. An appropriations request that includes the
12 full project budget will be executed once the design and engineering is complete.
13

14 **Q57. What should the Commission find with respect to Witness York's proposed**
15 **exclusion of the Trenton Channel Seawall project?**

16 A57. The Commission should find there is no reason to expect the Trenton Channel
17 Seawall project will not be completed. The project is required to restore sections
18 of the seawall that are in a failing state to ensure the protection of the waters of the
19 state and to maintain a safe condition. The project is in the best interest of the
20 community and continues to make progress as demonstrated by actual expenditures
21 and scope completed. Witness York's \$10.9 million disallowance recommendation
22 should be rejected.

²⁶ Witness York DT, page 21, lines 5-7.

Line
No.

1 **Part X – GLREA’s request for an electrical distribution system-connected BESS**
2 **analysis is unnecessary**
3

4 **Q58. What does Witness Richter recommend with respect to the Company’s plans**
5 **for future BESS capacity?**

6 A58. Witness Richter recommends that the Commission, “direct the Company to
7 carefully consider the benefits of installing future BESS capacity in smaller,
8 distribution-connected units, and that any future BESS proposal should include an
9 analysis of opportunities for distribution-connected BESS, and why that option
10 was, or was not, selected by the Company.”²⁷
11

12 **Q59. Did the DTE Electric Integrated Resource Plan (IRP) Case No. U-21193**
13 **indicate anything that is relevant to the procurement of new energy resources**
14 **by the Company?**

15 A59. The Order dated July 26, 2023, from the Company’s latest IRP case, Case No. U-
16 21193, states on page 5, “In acquiring the renewable and storage resources...the
17 Company will comply with the MPSC’s Competitive Procurement Guidelines for
18 Rate-Regulated Electric Utilities...” These Competitive Procurement Guidelines
19 were approved by the Commission via the September 9, 2021, Order in Case No.
20 U-20852.
21

22 **Q60. How do the Competitive Procurement Guidelines apply to the consideration**
23 **and evaluation of distribution-connected units?**

²⁷ Witness Richter DT, page 62 line 22 through page 63 line 2.

Line
No.

1 A60. The Competitive Procurement guidelines state, “Utilities should conduct an open,
2 non-discriminatory Competitive Procurement process that fairly considers both
3 third-party and utility ownership structures, resource types or combinations of
4 resource types, sizes/capacities, ancillary services, and cost reducing grid benefits
5 with transparency on how they will be evaluated.”²⁸ Additionally, the Competitive
6 Procurement Guidelines provide considerations for utilities in evaluating bids,
7 including but not limited to “...reductions in transmission congestion and loss
8 costs, reduced distribution system losses, deferred or avoided transmission or
9 distribution investments, and other locational benefits as applicable.”²⁹

10

11 **Q61. What do you conclude about Witness Richter’s recommendations?**

12 A61. The Competitive Procurement guidelines already require the open and transparent
13 consideration and evaluation of distribution-connected resources, including
14 different ownership structures and the benefits that different projects can provide,
15 including distribution-level benefits. Thus, no further action is necessary by the
16 Commission and Witness Richter’s recommendation should be disregarded.

17

18 **Q62. Does this conclude your rebuttal testimony?**

19 A62. Yes, it does.

²⁸ Case No U-20852 Order dated September 9, 2021, Exhibit A, Competitive Procurement Guideline 3.a.

²⁹ Case No U-20852 Order dated September 9, 2021, Exhibit A, Competitive Procurement Guideline 4.f.

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-21534

REBUTTAL TESTIMONY

OF

SHANNEN M. HARTWICK

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF SHANNEN M. HARTWICK

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Shannen M. Hartwick (she/her/hers), Director of Conversion Projects,
4 One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy
5 Corporate Services, LLC, a subsidiary of DTE Energy Company.

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to refute certain positions of the Attorney
14 General (AG), Michigan Environmental Council (MEC), and Natural Resource
15 Defense Council (NRDC), collectively referred to as “AG-MN” Witnesses
16 Stephens and Alvarez, and Michigan Public Service Commission (MPSC or
17 Commission) Staff (Staff) Witness DeCooman. The absence of a discussion of
18 other matters in my testimony should not be taken as an indication that I agree with
19 all other aspects of intervenor testimony.

20

21 **Q4. Are you sponsoring any exhibits in this proceeding?**

22 A4. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-53	RR1	Discovery Response – MNSCDE-7.1(c)
A53	RR2	Automation Prioritization Tool

Line
No.

1 **Q5. Were these exhibits prepared by your or under your direction?**

2 A5. Yes, they were.

3

4 **Q6. How is your testimony organized?**

5 A6. There are twelve specific issues I will rebut in my testimony, as listed below. A
6 detailed discussion of why the intervenor's recommendations should not be
7 accepted by the Commission follows.

8

9

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7		

8 **Part I - Distribution Automation**

9 **Q7. What are AG-MN Witness Stephens' recommendations regarding the**

10 **Company's Distribution Automation program?**

11 A7. On page 41, lines 1-13, AG-MN Witness Stephens recommends the Commission
 12 should require the Company to deploy a benefit-cost model to govern Distribution
 13 Automation deployment on a circuit-specific basis. He further recommends on
 14 page 41, lines 14-19, that until a circuit-specific Distribution Automation model
 15 can be developed the Commission limit the Distribution Automation deployment
 16 budget to the annual amount the Commission approved in U-21297 (\$27.167
 17 million less a 10% reduction recommended by Staff in that case).

18

19 **Q8. Why does Witness Stephens make these recommendations?**

20 A8. Witness Stephens provides a variety of reasons summarized below:

- 21 1) DTE Electric provides no measurable safety basis to support investments.
- 22 a) DTE Electric provides no measurable safety basis to support the investment
- 23 request for Distribution Automation.¹
- 24 b) The wire down risk on DTE Electric's 4.8kv circuits has existed for 75-120
- 25 years.²

¹ Stephens DT, p. 40, lines 6-9.

² Stephens DT, p. 40, lines 11-12.

Line
No.

- 1 c) A 4.8kV automated switch cannot be used on a 13.2kV circuit and could
2 render money spent on 4.8kV circuits being converted in the next 15 years
3 largely wasted.³
- 4 2) Drawbacks of Automation
- 5 a) Automated switches may operate incorrectly.⁴
- 6 b) In storm situations, where damage is widespread, intact circuits from which
7 to reroute power may not be available, negating Distribution Automation
8 value.⁵
- 9 c) The switches are costly and in his experience he believes one tie line/switch
10 per circuit is typically optimum.⁶
- 11 d) Distribution Automation is most often cost-effective when tie lines between
12 circuits have already been built.⁷
- 13 e) Distribution Automation is a solution that addresses a symptom, not root
14 causes and is not a cure-all, and is only appropriate for some circuits.⁸
- 15 3) The Company's automation prioritization tool is not designed to quantify
16 benefits in dollars.
- 17 a) The Automation Prioritization tool is not designed to quantify benefits in
18 dollars, enabling a comparison to cost and a risk-informed, dollar-
19 denominated benefit-cost analysis is what is needed.⁹
- 20 b) The Distribution Automation circuit model should reflect all costs,
21 including the cost to construct tie-lines between circuits.¹⁰

³ Stephens DT, p. 40, lines 17-19.

⁴ Stephens DT, p. 38, lines 20-21.

⁵ Stephens DT, p. 38, lines 21-22.

⁶ Stephens DT, p. 39, lines 1-3.

⁷ Stephens DT, p. 39, lines 4-7.

⁸ Stephens DT, p. 39, lines 9-12.

⁹ Stephens DT, p. 39, lines 14-21.

¹⁰ Stephens DT, p. 41, 9-13.

Line
No.

1 Rebuttal Issue 1: AG-MN Stephens' claim that DTE provides no measurable safety basis
2 to support investments is incorrect based upon the safety data provided

3 **Q9. How does Witness Stephens describe DTE Electric's Distribution Automation**
4 **Program?**

5 A9. Witness Stephens summarizes¹¹ the purpose and benefits of distribution
6 automation, when he states "Distribution Automation employs sophisticated
7 switches which automatically reconfigure the grid, avoiding time spent by
8 dispatchers (trying to figure out the best reconfiguration) and crew travel time (to
9 throw the switches). Distribution Automation can therefore reduce the duration of
10 service interruptions for some customers initially impacted by a fault. The
11 sophistication of the switches adds some value too; remote communication and
12 control are standard, and the switches incorporate line sensors for monitoring grid
13 status with precision (voltage, current, frequency, phase balance, etc.)."

14

15 **Q10. Do you agree with Witness Stephens summary of Distribution Automation**
16 **benefits?**

17 A10. Yes, although he does not mention all of the benefits of Distribution Automation.
18 In addition to improving reliability and shortening duration of outages, there are
19 safety benefits the sophisticated switches (i.e., reclosers) provide on the Company's
20 4.8kV delta system.

21

22 **Q11. What is Witness Stephens' claim regarding Automation safety benefits?**

23 A11. Witness Stephens claims that DTE Electric provides no measurable safety basis to
24 support the investment request for Distribution Automation.¹²

¹¹ Stephens DT, p. 38, lines 11-18.

¹² Stephens DT, p. 40, lines 6-9.

Line
No.

1 **Q12. Does the Company agree with Witness Stephen' claim that the Company has**
2 **not provided support for the measurable safety benefit of automation in the**
3 **4.8kV delta system?**

4 A12. No. As mentioned in my direct testimony,¹³ the Company has included a unique
5 consideration when deploying its Distribution Automation strategy due to the
6 nature of the ungrounded 4.8kV delta system. The Distribution Automation
7 program includes start of circuit reclosers on the 4.8kV circuits that provide new
8 capability to detect when a ground occurs on a circuit, as well as the ability to isolate
9 the grounded circuit. Having the start of circuit reclosers with the ground detection
10 capability allows the Company to quickly detect and mitigate potential safety
11 hazards due to energized downed wires through automated isolation. Without these
12 devices and the ground detection capability, field crews would need to patrol to
13 locate and mitigate the safety hazards of downed wires that could potentially remain
14 energized for a longer period of time.¹⁴

15

16 **Q13. Did the Company quantify the estimated safety benefits of Distribution**
17 **Automation?**

18 A13. Yes. On page SMH-15 lines 1-4 of my direct testimony, the Company states the
19 circuits being automated in 2025 see an average of 17 downed wires per year. With
20 the start of circuit recloser, these potentially energized downed wires would be
21 detected and isolated very quickly. Additionally, the Company submitted the
22 Distribution Automation Prioritization tool¹⁵ in discovery, as well as the list of

¹³ Hartwick DT, p. SMH-13, lines 12-21.

¹⁴ Hartwick DT, p. SMH 14, lines 4-25.

¹⁵ Ex. A-53, Sch. RR2

Line
No.

1 circuits planned for automation in 2025 in discovery response MNSCDE-7.1(c).¹⁶

2 The tool shows the historical wire downs associated with each specific circuit.

3

4 **Q14. Witness Stephens includes a statement that since the energized wire down risk**
5 **on DTE Electric's 4.8kv circuits have existed for the last 75-120 years and**
6 **automated switches have been available for more than a decade, DTE**
7 **Electric's sudden sense of urgency is unconvincing and warrants scrutiny.¹⁷**
8 **Does the Company agree that the current long lifespan of the 4.8kV circuits is**
9 **inconsistent with a sense of urgency to invest in this technology with known**
10 **safety benefits ?**

11 A14. No. While automated switches have been available for years, the ground detection
12 capability has recently been enabled by advancements in the logic algorithm
13 capability of the SEL651R relay, that is the G&W viper recloser controller. This
14 new logic algorithm, combined with the G&W Viper, is now able to derive safety
15 benefits in terms of ground detection, that were not previously available. The G&W
16 recloser with the SEL651R relay is now able to detect and isolate grounds on 4.8kv
17 circuits, mitigating potential safety hazards. The Company believes that improving
18 safety risk associated with potential energized downed wires is an important part of
19 the Distribution Automation program.

20

21 **Q15. What does Witness Stephens claim about the automated switches the**
22 **Company is using?**

23 A15. On page 40, lines 17-21, he appears to claim that the automated switches are voltage
24 specific when he says, "[a] 4.8kv switch cannot be used on a 13.2kv circuit".

¹⁶ Ex. A-53, Sch. RR1.

¹⁷ Stephens DT, p. 40, lines 11-14.

Line
No.

1 **Q16. Does the Company agree with this claim?**

2 A16. No. The Company has purchased and installed reclosers that are classified with
3 voltage capability of 15kV, which therefore can be used on both the 4.8kV and
4 13.2kV systems. Investments in reclosers today will be able to continue to be used
5 when circuits are converted from 4.8kV to 13.2kV.

6

7 Rebuttal Issue 2: AG-MN Stephens' claim that there are five Drawbacks of Automation

8 **Q17. What does Witness Stephens describe as the first drawback regarding**
9 **Distribution Automation?**

10 A17. He claims that automated switches may operate incorrectly, requiring crews to
11 drive from switch to switch anyway.¹⁸

12

13 **Q18. Does the Company Agree with Witness Stephens claim that Automated**
14 **switches may operate incorrectly?**

15 A18. While automated devices can have the remote possibility to operate incorrectly, the
16 G&W Viper is an industry proven and reliable device. DTE Electric follows a
17 robust process every time a new device is being evaluated to be approved for
18 deployment. In the case of the G&W Viper reclosers, this process included working
19 with Electric Power Research Institute (EPRI) to perform a thorough testing and
20 evaluation of the device,¹⁹ alongside with a live field installation and performance
21 evaluation before the device is formally approved to be used on the system.

22

¹⁸ Stephens DT, p. 38, lines 20-21.

¹⁹ EPRI. (2023, Oct 13). *Recloser Life-Cycle Management: G&W Viper ST 15kV Recloser*. EPRI.
<https://www.epri.com/research/products/000000003002027884>

Line
No.

1 **Q19. What does Witness Stephens describe as the second drawback regarding**
2 **Distribution Automation?**

3 A19. He claims that in storm situations, where system damage is widespread, intact
4 circuits from which to reroute power may not be available, negating Distribution
5 Automation value²⁰.

6
7 **Q20. Does the Company Agree that the benefits of distribution automation may not**
8 **apply to storm situations?**

9 A20. No. In fact, during storm situations, where damage may be widespread, reclosers
10 are well suited to automatically identify and isolate damaged areas without
11 intervention, thus enabling very fast restoration for portions of circuits, thereby
12 freeing crews up to perform other restoration jobs. The reclosers at the start of the
13 4.8kv circuits will detect and automatically isolate potentially energized downed
14 wires. The midpoint reclosers will operate when a fault is detected and isolate the
15 outage to a smaller area, impacting fewer customers. The reclosers at the tie points
16 provide the ability to remotely reconfigure circuits and reroute power around
17 damaged sections by connecting to adjacent circuits. Witness Stephens concern
18 was that these tie reclosers may not be able to operate during storms if the adjacent
19 circuit does not have power. In my direct testimony, SMH-15, lines 18-22, this
20 concern was addressed; the Company states their projected benefits of tie locations
21 were adjusted to account for catastrophic storm conditions during which adjacent
22 circuits may be impacted, thereby reducing the benefits. This condition was
23 addressed through a reduction to overall benefits of the Distribution Automation
24 Program, rather than on an individual circuit basis.

²⁰ Stephens DT, p. 38, lines 21-22.

Line
No.

1 **Q21. What does Witness Stephens describe as the third drawback regarding**
2 **Distribution Automation?**

3 A21. Witness Stephens claims the switches are costly, and in his experience, because of
4 the cost he believes that one tie line/switch per circuit is typically optimum. He
5 states he has observed investor-owned utilities install automatic switches beyond
6 the point of diminishing return.²¹

7
8 **Q22. Does the Company agree that one tie-line /recloser is optimal in all cases?**

9 A22. No. The Company's plan is to reduce the number of customers impacted by outages
10 and eliminate safety concerns due to potential energized downed wires. As
11 mentioned above, adding a recloser at the start of the 4.8kV circuits addresses safety
12 related issues due to potential energized wire down events. The optimal number of
13 devices installed on each circuit depends on the specific characteristics of each
14 unique circuit such as the circuit configuration, how many customers the circuit
15 serves, historical reliability performance of the circuit. The Company reviews each
16 circuit and performs an engineering review to determine the optimal number of
17 devices to install, specific to the characteristics of each circuit.

18
19 **Q23. What does Witness Stephens describe as the fourth drawback regarding**
20 **Distribution Automation?**

21 A23. Witness Stephens states that Distribution Automation is most often cost-effective
22 when tie lines between circuits have already been built,²² and care should be taken
23 to ensure tie lines are not being built where the benefits fail to outweigh the costs.

24

²¹ Stephens DT, p. 39, lines 1-3.

²² Stephens DT, p. 39, lines 4-7.

Line
No.

1 **Q24. Does the Company agree that Automation is most cost-effective when tie lines**
2 **between circuits have already been built?**

3 A24. While this statement made by Witness Stephens is not supported with specific data
4 or analysis for the Company to evaluate, the Company generally agrees that circuits
5 with established tie points are likely lower in cost to automate than a circuit where
6 a tie point has to be built. However, that does not imply that locations without an
7 established tie point are not cost-effective to automate. In addition, when
8 considering the full benefit-cost analysis, cost is not the only factor to consider,
9 benefits must also be considered. As mentioned in my direct testimony,²³
10 approximately 48% of the Company's distribution circuits already have established
11 tie points. "An additional 40% of the circuits either require some investment to
12 establish a tie point or require a detailed evaluation to determine if investment is
13 needed to increase emergency capacity needed to support service restoration."²⁴
14 The remaining 12% of circuits have physical restrictions making establishing tie
15 points difficult. In summary, the Company does not plan on building tie points on
16 every single circuit, but rather plans to evaluate each circuit individually to identify
17 if a tie point needs to be established and automated.

18

19 **Q25. What does Witness Stephens describe as the fifth drawback regarding**
20 **Distribution Automation?**

21 A25. Witness Stephens states that Distribution Automation is a solution that addresses a
22 symptom, not root causes and therefore is not a cure-all, and is only appropriate for
23 some circuits.²⁵

²³ Hartwick DT, p. SMH-15, lines 10-18.

²⁴ Hartwick DT, p. SMH-15, lines 12-15.

²⁵ Stephens DT, p. 39, lines 9-12.

Line
No.

1 **Q26. Does the Company agree with this statement?**

2 A26. The Company agrees that Distribution Automation is not a cure-all solution for all
3 grid problems, and additionally does not imply the program addresses root causes
4 of grid outages. Rather, the Distribution Automation program is designed to reduce
5 the number of customers impacted by an outage, shorten outage duration, and
6 mitigate potential safety hazards when there has been an outage on the system.

7

8 **Q27. Can you summarize the Company's support for the Distribution Automation**
9 **Program?**

10 A27. The Company's Distribution Automation program is designed to reduce the number
11 of customers impacted by an outage, shorten outage duration, and mitigate potential
12 safety risks on the 4.8kv system. The program was designed to address the unique
13 characteristics of the Company's distribution system. Distribution automation has
14 been proven to be an effective reliability improvement strategy that has been
15 utilized across the industry. As mentioned in my direct testimony, page SMH-11 to
16 SMH-12, the Distribution Automation technologies and Smart Grid Investment
17 Grant Projects discussed by the DOE in a 2016 report on the benefits of distribution
18 automation highlight five utilities who reported a 50-55% reduction in the number
19 of customer interruptions and customer minutes of interruptions per outage event
20 after deploying distribution automation. The estimated benefits from this program
21 are a significant part of the Company's plan to reduce customer interruptions and
22 restore customers faster when there has been an interruption. As stated in my direct
23 testimony, SMH-20, lines 3-10, the Company expects to reduce SAIDI on circuits
24 automated in 2025 by 47% and reduce system SAIDI by 45 minutes.

25

Line
No.

1 Rebuttal Issue 3: AG-MN Stephens' specific recommendation for a Distribution
2 Automation benefit-cost model, as opposed to the currently used prioritization tool
3 supporting Distribution Automation

4 **Q28. What does Witness Stephens recommend regarding a benefit-cost model?**

5 A28. Witness Stephens recommends the Commission should require the Company to
6 develop a benefit-cost model to govern Distribution Automation deployment on a
7 circuit-specific basis.²⁶

8

9 **Q29. How does Witness Stephens support his recommendation?**

10 A29. Witness Stephens does not explicitly state the reason for this recommendation,
11 although he provides details on what he believes should be in such a model. Earlier
12 in his testimony Witness Stephens describes many of the benefits of Distribution
13 Automation, including a reduction in service interruptions for customers²⁷. Based
14 on comments throughout his testimony, as I have discussed above, his concerns
15 appear to be mostly centered around ensuring the company deploys the program in
16 a cost-effective manner and believes a circuit-by-circuit benefit-cost model is
17 required to do so.

18

19 **Q30. Does the Company agree with Witness Stephens recommendation that DTE**
20 **Electric be required to develop a benefit-cost model to govern automation**
21 **deployment on a circuit-specific basis?**

22 A30. No. At this time the Company has a tool, the Distribution Automation Prioritization
23 tool, which was utilized to determine automation deployment for the test year. On

²⁶ Stephens DT, p. 41, lines 1-4.

²⁷ Stephens DT, p. 38, lines 11-18.

Line
No.

1 page 39, lines 14-18, Witness Stephens states that the Automation Prioritization
2 Tool is a step in the right direction, but that it does not quantify benefits in dollars.

3

4 **Q31. Can you please describe the Distribution Automation Prioritization tool?**

5 A31. The Distribution Automation Prioritization tool uses historical reliability and safety
6 data (wire downs), along with the unique topology of each circuit to determine the
7 projected reliability and safety benefits that Automation will provide for each
8 specific circuit. The tool assigns points to each circuit based on four key weighted
9 benefit criteria and divides the points by the estimated circuit investment dollars.
10 The circuits are then ranked by points per dollar, which the Company uses to
11 prioritize selection of circuits for Distribution Automation.

12

13 **Q32. Does this tool quantify the reliability and safety benefits of distribution**
14 **automation?**

15 A32. Yes. The tool projects the reliability and safety benefits from Distribution
16 Automation at a specific circuit level. The tool measures reliability in terms of
17 customer minutes of interruption, and safety benefits in number of potential live
18 wire downs avoided.

19

20 **Q33. Are these benefit projections utilized by the Company beyond**
21 **selecting/prioritizing circuits in the Distribution Automation program?**

22 A33. Yes. These benefit projections at a circuit specific level are inputs into the
23 Reliability model supported by Company Witness Kryscynski.

24

Line
No.

1 **Q34. What are the benefits of Distribution Automation projected by the Company**
2 **in the test year?**

3 A34. As stated in my direct testimony, pages SMH-15, lines 1-4 and SMH-20, lines 3-
4 10, based on the circuit specific model and circuits selected for 2025, the Company
5 expects to address ground detection and isolation for 149 4.8kv circuits, which see
6 an average of 17 downed wires per year, and is expected to reduce SAIDI on
7 impacted circuits by 47% reducing system SAIDI by 45 minutes.

8

9 **Q35. Can you provide any additional evidence that Distribution Automation has**
10 **measurable benefits?**

11 A35. Yes. The US Department of Energy (DOE), as part of the ARRA funding in 2008,
12 tracked the metrics of the equipment those grants provided, which included
13 distribution automation (DA) equipment. A DOE 2016 report titled “Distribution
14 Automation”²⁸ published the resulting improvements to metrics due to Distribution
15 Automation equipment investments. The DOE report, page 5, states “DA
16 technologies provided advanced capabilities for operators to detect, locate, and
17 diagnose faults. Fault location, isolation and service restoration (FLISR)
18 technologies can automate power restoration in seconds by automatically isolating
19 faults and switching some customers to adjacent feeders.” In a call out box on page
20 5, the DOE summarizes the impact of the \$7.9 billion in grants that deployed over
21 82,000 automation devices: “Per outage event, FLISR operations reduced number
22 of customers interrupted by 53% and reduced customer minutes of interruption by
23 53%”. Further, it goes on to state “[i]n 2013, 3 utilities reported System Average

²⁸DOE. (2016, Sep.). *Distribution Automation: Results from the Smart Grid Investment Grant Program*.
<https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report%2009-29-16.pdf>

Line
No.

1 Interruption Frequency Index (SAIFI) improvements of 17 to 58% from pre-
2 deployment baselines.” The study goes on to point to a massive storm related
3 outage in Chattanooga, TN during a derecho weather event in July of 2012, where
4 FLISR “helped operators restore system-wide power about 17 hours earlier than
5 without DA.” In a second storm in Chattanooga, TN two years later, FLISR “was
6 able to restore power 36 hours faster and reduce affected customers from 70,000
7 down to 33,000.” As demonstrated in the DOE study, Distribution Automation
8 equipment investments improved reliability, in that less customers were affected
9 by outages and outages were shorter in duration.

10

11 **Q36. Does the Company plan to make enhancements to the Automation**
12 **Prioritization tool in the future?**

13 A36. Yes. The Company plans to make enhancements to the Automation Prioritization
14 tool as part of an overall company effort discussed by Witness Kryscynski to further
15 advance BCAs to enhance our already strong investment analysis.²⁹ The
16 Automation Prioritization tool has all the foundational data and components already
17 established that the company will build upon to work towards a broader BCA
18 framework. Any effort to create an entirely new BCA for Distribution Automation
19 would duplicate extensive effort already put forth to develop the Automation
20 Prioritization tool.

21

22 **Q37. Does the Company agree with Witness Stephens recommendation that until a**
23 **circuit-specific Distribution Automation model can be developed the**
24 **Commission should limit the Distribution Automation deployment budget to**

²⁹ See further discussion on the Company’s plan for BCA improvements in Kryscynski Rebuttal
Testimony: Rebuttal Issue 5 “Benefit Cost Analysis”

Line
No.

1 **the annual amount the Commission approved in U-21297 (\$27.167 million less**
2 **a 10% reduction recommended by Staff)?**

3 A37. No. The Company's planned Distribution Automation investments provide clear
4 and compelling reliability and safety benefits to customers, as detailed above. The
5 entire automation program will take many years to implement and given that we
6 are in the very early stage of this automation journey, the prioritized initial
7 deployment is a clear no-regret investment that the company should aggressively
8 pursue. Furthermore, the Company's Distribution Automation Prioritization tool
9 prioritizes circuits based on benefits per dollar as detailed above. The benefits per
10 dollar were primarily considered in selecting which circuits to automate. This
11 current approach addresses circuits where Automation will provide the greatest
12 benefits to customers. Lastly, as mentioned above, the Company is working toward
13 a cost-benefit analysis.

14

15 **Part II - Grid Automation Telecommunications**

16

17 Rebuttal Issue 4: AG-MN Witness Stephens and Alvarez's recommendation to disallow
18 strategic capital associated with Grid Automation Telecommunications is inappropriate
19 due to prior approvals and support for 2024 and 2025 investments.

20 **Q38. What is AG-MN Witness Stephens' recommendation regarding Grid**
21 **Automation Telecommunications investments?**

22 A38. In the table on page 46 of his direct testimony, as well as in his unmarked Exhibit
23 MEC-11, Witness Stephens recommends a disallowance of \$16,900,000 for the
24 Bridge Period ending December 31, 2024, and \$15,000,000 for the Test Year, 12
25 months ending December 31, 2025.

Line
No.

1 **Q39. Does AG-MN Witness Stephens’ provide any other discussion of the proposed**
2 **disallowance for Grid Automation Telecommunications?**

3 A39. Witness Stephens’ only support is Witness Alvarez’s testimony. Witness Stephens
4 does not provide any additional support of his own.

5

6 **Q40. What is AG-MN Witness Alvarez’s recommendation regarding Grid**
7 **Automation Telecommunications investments?**

8 A40. On page 64, lines 1-2, of his direct testimony, Witness Alvarez recommends “that
9 the Commission disallow Telecommunications Plan costs incurred in 2022 and
10 remove Plan spending from the 2023-2024 bridge period and 2025 test year.”

11

12 **Q41. Is AG-MN Witness Alvarez’s recommendation regarding disallowance of Grid**
13 **Automation Telecommunications investments consistent with AG-MN**
14 **Witness Stephens?**

15 A41. No, Witness Stephens only proposes disallowance for 2024 of the bridge and test
16 year, while Witness Alvarez proposes disallowance of all Grid Automation
17 Telecommunications incurred to date.

18

19 **Q42. Does AG-MN Witness Alvarez’s provide any support or explanation for his**
20 **broader disallowance including historical investments?**

21 A42. No. There is no additional explanation or rationale provided and no exhibit or table
22 detailing this is provided.

23

24 **Q43. What is the purpose and necessity of telecommunications in supporting the**
25 **more safe, reliable grid of the future?**

Line
No.

1 A43. As described in my testimony,³⁰ the telecommunications network is the backbone
2 system that connects the distribution automation equipment in the field to the
3 System Operations Center (SOC). The network enables two-way communication
4 that provides visibility into grid conditions and SOC the ability to remotely operate
5 grid devices. An advanced telecommunications infrastructure plays a crucial role
6 in grid automation by providing reliable and secure communication channels for
7 data exchange between various grid devices such as sensors, meters, switches, and
8 control centers. These secure and reliable data exchanges enable programs like
9 Distribution Automation, Conservation Voltage Reduction (CVR), Volt-Var
10 Optimization (VVO), Advanced Metering Infrastructure, demand response, along
11 with other core components and advanced applications described in the Distribution
12 Grid Plan (DGP).³¹

13
14 **Q44. Have Grid Automation Telecommunications investments been approved by**
15 **the Commission in prior cases?**

16 A44. Yes. The December 1, 2023 order in U-21297 on page 121, “[t]he Commission
17 finds the ALJ’s recommendation to fund the bridge period but not the test year to
18 be well-reasoned and supported by the record and adopts the ALJ’s findings and
19 conclusion on this issue”. In Case No. U-21297, the Commission approved
20 \$14,206,000 for the 12 months ending December 31, 2022, and \$17,508,000 for the
21 11 months ending November 30, 2023. Since these investments have been approved
22 in the past, these investments are not being requested in the instant case and
23 therefore should not be retroactively disallowed.

24

³⁰ Hartwick DT, p. SMH-21 and SMH-24 through 26.

³¹ Kryscynski Exhibit A-23, Sch. M8

Line
No.

1 **Q45. What investments are being requested in the instant case?**

2 A45. In the instant case, the Company is requesting \$35,738,000 of investment beyond
3 prior rate case approvals to continue investments in this vital part of building the
4 grid of the future. In Table 1 below, the amount requested in the instant case,
5 column (d), is the Grid Automation Telecommunications Investments in column
6 (c) less the amount approved in Case No. U-21297 in column (b).

7

8 **Table 1 - Grid Automation Telecommunications Request (000s)**

(a)	(b)	(c)	(d) = (c) - (b)
Period	Approved in U-21297	Investment in U-21534	Request in U-21534
11 mos. Ending Nov 30, 2023	17,508	19,770	2,262
Dec 2023	0	1,576	1,576
2024	0	16,900	16,900
2025	N/A	15,000	15,000
Total	17,508	53,246	35,738

9

10 **Q46. What reasons does AG-MN Witness Alvarez offer to support his**
11 **recommended Grid Automation Telecommunication disallowance?**

12 A46. Witness Alvarez states three reasons for his recommendation on page 64, lines 3-7
13 of his direct testimony: “1) That DTE has not developed a benefit-cost or make vs.
14 buy analysis that supports its spending or Plan; 2) That the Company has not
15 complied with the Commission’s Order to analyze alternatives to its Plan; and 3)
16 That DTE refused to provide the Plan, of which the historical and proposed
17 spending in its Application constitute a foundational part”.

18

Line
No.

1 Rebuttal Issue 6: AG-MN Witness Alvarez states “DTE refused to provide the [Grid
2 Automation Telecommunication] Plan” despite the Company providing details for our
3 2024 and 2025 investments.

4 **Q47. What does AG-MN Witness Alvarez conclude about the overall Grid**
5 **Automation Telecommunication plan?**

6 A47. Witness Alvarez concludes that the 2025 investments cannot be evaluated without
7 understanding the entire plan.³²

8
9 **Q48. Does the Company agree with AG-MN Witness Alvarez in his conclusion?**

10 A48. No. The clear distinction between investments in the instant case and those that are
11 planned for beyond 2025 has been stated in both testimony³³ and discovery³⁴. The
12 investments in this case have definitive purpose to connect critical sites such as
13 generation sites, subtransmission stations, substations, service centers and
14 communications towers, with high-speed, high-bandwidth, and reliable connection.
15 Witness Alvarez ignores any inherent benefit in providing connectivity to critical
16 sites and fails to acknowledge there are current benefits from fiber standalone
17 investments, such as optionality and flexibility for the future. For the investments
18 beyond 2025, the telecommunications plan will shift focus and scope of
19 investments to remaining substations and last mile investments that will be
20 presented in the 2025 DGP and the next rate case.

21

³² Alvarez DT, p. 59 lines 15-17 and p.60 lines 1-2

³³ Hartwick DT, p. SMH-27, lines 15-21

³⁴ Alvarez Ex MEC-8, Company response to MNSCDE-7.4(c)

Line
No.

1 **Q49. What is the AG-MN Witness Alvarez’s first concern made regarding the scope**
2 **of future Telecommunications Investments of DTE Electric’s Grid**
3 **Automation Telecommunications Plan?**

4 A49. Witness Alvarez states on page 59 of his direct testimony, lines 11-12, that “[t]he
5 Company refused to provide details for the plan beyond 2025, citing that details for
6 the Plan beyond 2025 are beyond the scope of the Company’s application.”

7
8 **Q50. Does this statement accurately reflect what the Company has provided in the**
9 **instant case?**

10 A50. No. While the Company did state in discovery response MNSCDE-7.4(b), which
11 is provided in Witness Alvarez’s Exhibit MEC-8, that the “deployments in 2026
12 and beyond are outside of the instant case”. The Company provided a list of our
13 2024 and 2025 fiber deployments by route and identified the substations associated
14 with each route.

15
16 The absence of exact routes to be deployed beyond 2025 does not warrant
17 disallowance in the instant case, as they are distinct from the instant case
18 investments to connect critical distribution sites. However, the absence of the exact
19 routes beyond 2025 can be understood as explained in my direct testimony on page
20 SMH-27, lines 19-20, the plan beyond the instant case “will continue to expand the
21 telecommunication network to the next tier of locations that are prioritized from a
22 resiliency perspective.” Page SMH-48, lines 1-3 of my testimony also explains that
23 “[i]n 2026 and through the end of the program, fiber routes will run through a cost
24 benefit analysis to support the selection of the appropriate future technology to be
25 used.” Both sentiments were reiterated in the Company’s MNSCDE-7.4(c)

Line
No.

1 discover response, provided in Witness Alvarez's Exhibit MEC-8, along with the
2 acknowledgement that the tool for determining deployments beyond 2025 is not yet
3 complete.

4

5 **Q51. What is AG-MN Witness Alvarez's second concern regarding the scope of**
6 **future Telecommunications Investments of DTE Electric's Grid Automation**
7 **Telecommunications Plan?**

8 A51. Witness Alvarez states on page 59, lines 12-14, of his direct testimony that "[t]he
9 Company's 2023 Distribution Grid Plan³⁵ provides no additional information on
10 the Telecommunications Plan."

11

12 **Q52. Does the 2023 Distribution Grid Plan have information on Grid Automation**
13 **Telecommunications?**

14 A52. The Company's 2023 Distribution Grid Plan (DGP) does in fact provide additional
15 information on the Telecommunications Plan. A graphical overview of DTE
16 Electric's Future Network Technology Landscape is presented in DGP Exhibit
17 10.1.5.2 on page 141 of Exhibit A-23, Schedule M8 (sponsored by Company
18 Witness Kryscynski) along with a general summary work between 2024 and 2028.
19 Additionally, projected yearly investments from 2024 through 2028 is provided in
20 Exhibit 10.1.3 on page 137 of Exhibit A-23, Schedule M8. It is worth noting that
21 Witness Alvarez's statement about the cost of the telecommunications plan
22 referenced Exhibit A-23, Schedule M8, page 137 in his summary of the plan.³⁶

23

³⁵ Kryscynski Ex. A-23, Sch. M8

³⁶ Alvarez DT, p. 58, line 18.

Line
No.

1 **Q53. Has the Company provided the overall plan for Telecommunications and**
2 **appropriate support for the requested Telecommunications investments that**
3 **are included instant case?**

4 A53. Yes. For clarity I will provide a brief overview here. The general
5 Telecommunications plan scope as stated in the DGP, Exhibit A-23, Schedule M8,
6 page142-143, is as follows: “Between 2024 and 2028 fiber routers will be installed
7 to complete fiber loops and provide communications to end points. This work will
8 include installing communication poles, fiber entrances and taps along installed
9 routes to make final connections into substations and support the advanced mesh
10 network deployment with additional mesh nodes.”

11
12 Testimony, pages SMH-25 through SMH-28, segregates the plan into three general
13 phases. (1) Installation and commissioning of the fiber backbone to critical sites
14 will continue through 2025. (2) Investments in 2026 through 2028 will focus on
15 extending of the backhaul network to next tier locations that cannot be sufficiently
16 served by existing deployed technologies or currently do not have communications
17 capabilities. (3) Finally, future investments beyond 2028 in grid
18 telecommunications will focus on building out the last mile network to pole top
19 devices.

20
21 For the instant case, the first phase, the installation of the backbone to critical sites,
22 will run through the end of the test year—2025. A listing of more detailed work
23 scope planned and installed between 2022 and 2025 is listed on pages SMH-42
24 through SMH-45. Additionally, exact routes were provided in MNSCDE-7.4(b),
25 presented in Witness Alvarez’s Exhibit MEC-8, for 2024 and 2025.

Line
No.

1 Rebuttal Issue 7: AG-MN Witness Alvarez’s opinion that the Alternative Analysis
2 provided in the instant case failed to meet the Commission’s previous request is incorrect
3 based upon the record.

4 **Q54. What did the Commission order the Company to do in U-21297 in regard to**
5 **analysis supporting Grid Automation Telecommunications?**

6 A54. The Commission ordered DTE Electric to analyze a variety of alternatives before
7 advancing its Grid Automaton Telecommunications Plan further by agreeing with
8 the ALJ’s recommendation, affirming “[the ALJ] further found that the company
9 should be required to provide an analysis of alternatives when requesting further
10 extensions of the fiber network.”³⁷

11

12 **Q55. Did the Company comply with the Commission’s order to provide an analysis**
13 **of alternatives to support the continued investments in the backhaul fiber**
14 **network?”**

15 A55. Yes. As provided in my direct testimony, pages SMH-29 to SMH-42, I presented
16 an assessment of communication alternatives for the backhaul network investments
17 through 2025. The assessment evaluates Public Cellular, Private Long-Term
18 Evolution (LTE) Cellular, Point-to-Multipoint and Point-to-Point Microwave,
19 Wireless Mesh, Leased fiber, and Company-owned (i.e., “Private”) fiber options.
20 As part of the assessment, there is a description of each technology, the Company’s
21 current level of utilization, and key considerations in evaluating cost considerations
22 as well as the benefits of each technology.

23

³⁷ December 1, 2023 Order in U-21297. p. 119-122

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1 The alternatives were compared through the lens of reliability, life cycle factors,
2 and initial cost factors in Figures 3-5 of my testimony. This evaluation of the
3 different options and ranking was based on the expertise of a group of subject
4 matter experts with a combined experience of over 50 years in telecommunication
5 domain expertise.

6

7 **Q56. What feedback does AG-MN Witness Alvarez provide in his testimony on the**
8 **analysis methodology, options and ranking of factors in the**
9 **Telecommunications Alternative Analysis?**

10 A56. Witness Alvarez did not provide feedback on the options or ranking of factors. His
11 opinion on the analysis methodology is that it is not “remotely adequate”³⁸.

12

13 **Q57. Why is the alternative analysis the appropriate tool to evaluate the expansion**
14 **of the backhaul network through 2025?**

15 A57. The investments through 2025 are supporting communications from our Electric
16 System Operations Center and Alternative System Operations Center to our sub
17 transmission and distribution stations, service centers, communication towers and
18 generation sites throughout the service area. The appropriate question to ask for
19 these investments is “What technology meets the requirements to have secure and
20 reliable communications?”

21

22 The primary factors considered were the ability of the technology to fully serve the
23 bandwidth (amount of data) and latency (delay in transmitting data) needs, and the
24 reliability and the essential cybersecurity characteristics of those systems for
25 providing service to critical sites and infrastructure.

Line
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1 **Q58. How was reliability evaluated in the alternative analysis?**

2 A58. For the technologies, the reliability is shown in Figure 3 of my testimony.³⁸

3 Reliability was evaluated based upon Bandwidth, Low Latency, Network Control,

4 Prioritization and Quality of Service, Security, Maintenance Window Scheduling,

5 Disaster Recovery, Control of Communications During Emergency and Protection

6 Against Interference and FCC Decisions.

7

8 **Q59. How were life cycle costs considered in the alternative analysis?**

9 A59. As shown in Figure 4 of my testimony,³⁹ life cycle factors were ranked in the
10 alternative analysis. Various technologies are compared across Ongoing Operating
11 Costs (Excluding Staffing), Staffing, Open Standards, Technology Availability,
12 Technology Stability and Technology Lifespan.

13

14 **Q60. Were initial costs considered in the alternative analysis?**

15 A60. Yes. In Figure 5,⁴⁰ the initial costs of the technologies were compared across
16 Control of Geography Covered, Device Deployment Effort and Installation Cost.

17

18 **Q61. Which investments are supported by the alternative analysis?**

19 A61. The technology alternative analysis shown in Figures 3-5 of my direct testimony,
20 page SMH-39 to SMH-40, supports the use of Company-owned fiber for the
21 backhaul network to connect critical assets. The associated investment in the
22 current case is \$35.7 million.

23

³⁸ Hartwick DT, p. 39, Figure 3.

³⁹ Hartwick DT, p. SMH-40, Figure 4.

⁴⁰ Hartwick DT, p. SMH-40, Figure 5.

Line
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1 Rebuttal Issue 8: AG-MN Witness Alvarez’s recommendation for Benefit-Cost or Make
2 vs. Buy Analysis is inappropriate for investments within the test year

3 **Q62. What is AG-MN Witness Alvarez’s final reason for the Grid Automation**
4 **Telecommunication disallowance?**

5 A62. Witness Alvarez’s final reason is “DTE has not developed a benefit-cost or make
6 vs. buy analysis that supports its spending or Plan”⁴¹

7
8 **Q63. What does AG-MN Witness Alvarez recommend a make vs. buy study**
9 **include?**

10 A63. In his testimony, he explains of a comprehensive make vs. buy study would
11 “compare the pros and cons of each technology on technical, operational,
12 cybersecurity, reliability, and other characteristics, and compare these pros and
13 cons to the risks associated with each technology (generally, the size of the up-front
14 investment) and the cost of each technology not just initially, but over the lifetimes
15 of each alternative’s operation”⁴²

16
17 **Q64. Has DTE Electric provided the make vs. buy study characteristics AG-MN**
18 **Witness Alvarez suggests in the instant case?**

19 A64. Yes. As shown in the table below, DTE Electric has provide qualitative
20 characteristics of a comprehensive make vs. buy analysis to support investments in
21 the instant case.

22

⁴¹ Alvarez DT, p. 64, lines 3-4.

⁴² Alvarez DT, p. 62, lines 7-11.

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1

Table 2 - Make vs. Buy Characteristics

Characteristics Evaluated	Inclusion in U-21534
Pros and cons of technical characteristics	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Pros and cons of Operational characteristics	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Pros and cons of Cybersecurity characteristics	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Pros and cons of Reliability characteristics	Figure 3 on page SMH-39 and Exhibit A-19 Schedule I1.1
Risks	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Initial Cost	Figure 5 on page SMH-40
Lifetime Cost	Figure 4 on page SMH-40

2

3 **Q65. Has the Company committed to developing a cost benefit analysis for the next**
4 **phase of the Telecommunications program?**

5 A65. Yes. My direct testimony, page SMH-48, lines 1-4 states “[i]n 2026 and through
6 the end of the program, fiber routes will be analyzed using a cost benefit analysis
7 to evaluate future technology alternatives to support the essential
8 telecommunications needs of all other DTE Electric investments and programs.”

9

10 **Q66. What is the Company’s journey in developing BCAs?**

11 A66. As discussed by Witness Kryscynski, the Company developed a new BCA
12 methodology for two investment areas, PTMM and undergrounding, and provided
13 these BCA spreadsheets and calculations as part of the case. The company intends
14 to move in the direction of conducting more BCAs to enhance our already strong

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1 investment analysis provided in the Global Prioritization Model and Reliability
2 Model.⁴³

3

4 **Q67. Has the Company continued its efforts to develop a BCA for Grid Automation**
5 **Telecommunications after the filing the instant case?**

6 A67. Yes. The Company is currently developing the cost benefit analysis tool for
7 determining fiber deployments beyond 2025, but it has not yet been completed.

8

9 **Q68. What level of precision is AG-MN Witness Alvarez seeking in either a “make**
10 **vs. buy” or benefit cost analysis?**

11 A68. In Witness Alvarez’s testimony, he states “Assessments of the characteristics of
12 various alternatives should also be supported by data. For example, it would not be
13 enough for DTE Electric to claim that a public carrier’s service is insufficiently
14 reliable; DTE Electric must identify the frequency with which commands issued
15 over DTE Electric’s owned network failed compared to the frequency at which
16 commands issued through the public carrier’s network failed.”⁴⁴

17

18 And that “DTE should provide the consequence of the difference to customers. For
19 example, of the increased failure rate observed (hypothetically) in commands
20 issued over a public carrier network how many resulted in service interruptions to
21 customers, and what were the consequences to customers (in dollars) of these
22 service interruptions?”⁴⁵

23

⁴³ See further discussion on the Company’s plan for BCA improvements in Kryscynski Rebuttal
Testimony: Rebuttal Issue 5 “Benefit Cost Analysis”

⁴⁴ Alvarez DT, p. 62 lines 14-18

⁴⁵ Alvarez DT, p. 62 line 19 – p.63 line 3

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1 **Q69. Is it practicable to meet this level of precision in identifying the most**
2 **appropriate communications solution given a variety of situations and**
3 **circumstances?**

4 A69. No. Witness Alvarez's proposed method would likely require the construction and
5 operation of parallel utility owned and third-party telecommunication systems. To
6 adequately compare the technologies, they would need to operate under similar
7 circumstances. The actual performance data would need to be recorded over enough
8 time to be statistically significant.

9
10 Witness Alvarez further indicates that the Company should develop a tool to derive
11 the appropriate solution for each circumstance from this data⁴⁶. To accurately
12 develop a tool which uses both utility and third-party data for the six technologies
13 compared in Figures 3-5 of my testimony,⁴⁷ results in twelve models for each
14 operating circumstance. Such a model would be complex to maintain and operate.
15 Even Witness Alvarez concedes that "DTE ... does not possess the data needed to
16 inform the development of such a tool."⁴⁸

17
18 **Q70. Should the Commission accept Witnesses Alvarez's and Stephens's**
19 **recommended disallowances for the Grid Automation Telecommunications?**

20 A70. No. First, the Company provided details of our Grid Automation
21 Telecommunications in my direct testimony, discovery and in the Distribution Grid
22 Plan. Second, the Company complied with the Commission's request for an
23 alternative analysis, which includes the characteristics endorsed by Witness

⁴⁶ Alvarez DT, p. 63, lines 6-11

⁴⁷ Hartwick DT, p. SMH-39-40, Figures 3-5.

⁴⁸ Alvarez DT, p. 63, lines 11-12

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1 Stephens. Third, the Company is committed to furthering our analysis of future
2 telecommunications by submitting a benefit cost analysis in our next rate case.

3

4 Rebuttal Issue 9: AG-MN Witness Alvarez's other recommendations

5 **Q71. Does Witness Alvarez provide any additional recommendations regarding**
6 **Grid Automation Telecommunications?**

7 A71. Yes. Witness Alvarez provides two additional recommendations.

8 1. I further recommend that the Commission order the Company to solicit an
9 independent expert to complete a comprehensive analysis of technical,
10 operational, cybersecurity, and reliability pros and cons of various
11 telecommunications options, and to compare these options to the risk and total
12 lifecycle costs associated with each option;⁴⁹

13 2. I further recommend that the Commission order the Company to complete a
14 tool that appropriately identifies the best alternative to employ in various
15 situations and circumstances.⁵⁰

16

17 **Q72. Does the company agree with Witness Alvarez's two additional**
18 **recommendations?**

19 A72. No. In Witness Alvarez's testimony he recommends four different analyses be
20 performed:

- 21 1. Benefit Cost Analysis;
22 2. Make vs. Buy Analysis;
23 3. A comprehensive analysis by an independent expert;
24 4. A tool to identify the best alternative.

⁴⁹ Alvarez DT, p. 64, lines 8-11.

⁵⁰ Alvarez DT, p. 64, lines 11-14.

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1 The Company does not believe all four analyses are required at this time and are
2 redundant of each other. In the instant case, the Company provided a comparative
3 analysis of alternative technologies on pages SMH-29 through SMH-42 of my
4 testimony for use connecting critical distribution sites pursuant to the
5 Commission's order in Case No. U-21297 on December 1, 2023. Additionally, the
6 Company is committed to developing a benefit cost analysis for determining
7 deployments beyond 2025, as stated in my direct testimony on page SMH-48, lines
8 1-4. The tool is not yet completed and was acknowledged in MNSCDE-7.4(c),
9 presented in Witness Alvarez's Exhibit MEC-8.

10

11 Rebuttal Issue 10: AG-MN Witness Alvarez's unsupported technical presumptions

12 **Q73. Does AG-MN Witness Alvarez claim DTE Electric has presumptions related**
13 **to Telecommunications that are not supported?**

14 A73. Yes. In reviewing the Company's Telecommunications Plan/projects, Witness
15 Alvarez states "[t]he Company makes two critical presumptions in support of its
16 Plan. These include: 1) that many new technologies require real-time
17 communications; and 2) of all available options, Company-owned options provide
18 the best combination of speed, control, security, and reliability."⁵¹

19

20 **Q74. Are real-time communications required to operate the technologies in a**
21 **modern grid?**

22 A74. Yes. In technology applications, the delay before a transfer of data begins is a
23 measurable term called "latency." Distribution Automation applications have strict
24 latency requirements, with most SCADA devices requiring a latency lower than

⁵¹ Alvarez DT, p. 60, lines 5-8

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1 200ms. For a backhaul network, a latency <50ms is required.⁵² These real-time
2 communications are required to provide device responses to remote commands,
3 supply the precise timing needed for protection schemes to ensure the grid is
4 operating within tolerances, and execute the automatic operation of devices. ADMS
5 control schemes perform real-time calculations, and any delays in field data used
6 in the control schemes can cause model simulation results to become invalid and
7 desynchronized. These and more use cases in the modern grid, as described in the
8 DGP⁵³, require low latency.

9

10 **Q75. Did the Company presume Company-owned options provide the best**
11 **combination of attributes as AG-MN Witness Alvarez stated?**

12 A75. No. Various technologies were evaluated as I describe in my testimony on pages
13 SMH-29 through SMH-42 for connecting critical distribution sites as part of the
14 backhaul network. There are benefits to Company-owned systems that I will briefly
15 describe here. In terms of security, a company-controlled network provides the
16 ability to tailor the security to the specific application. The flexibility that Witness
17 Alvarez implies⁵⁴ third-party systems may offer by being able to be procured as
18 needed is significantly limited by their technical implementation and commercial
19 terms, as well as the geographic range and quality of coverage and is not a good fit
20 for use cases where the duration of use will likely be multiple decades. Third-party
21 networks introduce complexity because a demarcation point where the third-party
22 system connects to the Company's distribution system must be set up, and the

⁵² Kuzlu, Murat & Pipattanasomporn, Manisa. (2013). Assessment of communication technologies and network requirements for different smart grid applications. Innovative Smart Grid Technologies (ISGT), 2013 IEEE PES. 1-6. 10.1109/ISGT.2013.6497873.

⁵³ Kryscynski Exhibit A-23, Schedule M8

⁵⁴ Alvarez DT, p.61, lines 7-8

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1 uncertainty in routing and troubleshooting due to proprietary systems can
2 complicate both the setup and operations. Long term costs are also a consideration
3 in third-party technologies. Third-party systems typically have a cost-of-service
4 model that includes high bandwidth usage over long periods of time accruing
5 significant costs that are subject to price increases and terms of service changes.
6 The Company has experienced challenges with the reliability of third-party systems
7 both in day-to-day performance variation, unnotified and unscheduled maintenance
8 windows and sporadic drops outs as well as major regional outages of carrier
9 systems. I've included details in Exhibit A-19, Schedule I1.1. The Company has
10 also been required to make unexpected investments due to third-party business
11 decisions, such as when a public carrier forced DTE Electric to invest \$36 million
12 to remediate and install new equipment to replace working assets.

13

14 **Part III - NWA: Adaptive Networked Microgrid**

15 Rebuttal Issue 11: Staff Witness DeCooman recommends the full disallowance of the
16 NWA: Adaptive Networked Microgrid project until the funding agreement is finalized.

17

18 **Q76. What is Witness DeCooman's recommendation for the NWA: Adaptive**
19 **Networked Microgrid project?**

20 A76. On page 21, lines 10-20 of testimony, Witness DeCooman states "Staff
21 recommends a full disallowance of all requested capital expenditures for the
22 [Adaptive Networked Microgrid] pilot, totaling \$4,588,307 and \$25,550,184 in the
23 bridge and test years, respectively. Staff is also recommending the corresponding
24 partner contributions and grant funding which offset a portion of these costs be
25 credited, to ensure this pilot has no impact on the revenue requirement, totaling

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1 \$2,608,544 and \$13,109,827 in the bridge and test years, respectively. While Staff
2 is generally supportive of this pilot and the value that it could provide the Company
3 through the development and operation of adaptive microgrids, Staff does not find
4 it appropriate to include this pilot in rates when the status of the Company's grant
5 application is uncertain, particularly given the Company's indication it would likely
6 not proceed with this project if this grant funding is not approved."

7

8 **Q77. How does the Company respond to Witness DeCooman's recommendation?**

9 A77. The Company appreciates the Staff's support and interest in the Adaptive
10 Networked Microgrid project. The Company will continue working diligently with
11 the Department of Energy to reach a funding agreement to legally secure the grant
12 funding and commence engineering and design. Since the as-filed in-service date
13 of the project is 2027, the disallowance of NWA: Adaptive Networked Microgrid
14 does not impact the revenue requirement.

15

16 **Part IV - Rebuttal Issue 12: General Rebuttal Points**

17 **Q78. Have any intervenors requested that the MPSC direct the Company to**
18 **undertake any specific activities related to distribution infrastructure or**
19 **processes?**

20 A78. Yes, intervenors have suggested a collection of conceptual proposals that they wish
21 the Commission to order the Company to undertake and they are listed in the table
22 below. However, as a group these suggested directives are undefined and largely
23 lack the detail requisite to even be thoroughly considered. The time, resources,
24 costs, and other inputs necessary to even begin these tasks have neither been
25 discussed nor even listed; the resultant values have not been calculated nor

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1 considered; alternatives have not been identified nor compared. In an attempt at
 2 brevity the Company is not rebutting all the unsupported and misguided
 3 suggestions individually, all of these requested directives should be denied.

4

5

Table 3 - General Rebuttal Issues

Witness	Rebuttal Point	Rebuttal
ABATE – York	Regarding distribution capital strategic replacements, on page 31, lines 6-11 of Witness York’s direct testimony, she recommends that “the Commission allow only the projected capital expenditures associated with projects that are expected to be in-service during the bridge period and projected test year. ”	Page 70 of Company Witness Uzenski’s direct testimony, lines 19-25 (Q&A 135) states that for capital expenditures on projects that will not be in service during the projected test period do not have a current revenue requirement. Additionally, the Commission found Witness York’s similar proposed adjustments in case No. U-21297 unpersuasive by stating that “the Commission does not find that the question of whether a project will be completed within the test year is dispositive as to whether that project belongs in rate base.” ⁵⁵ The Company recommends the Commission disregard Witness York’s recommendation in the instant case.

6

7 **Q79. Does this conclude your rebuttal testimony?**

8 A79. Yes, it does.

⁵⁵ Page 84 of Commission Order issued in Case No. U-21297 and dated December 1, 2023

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.)

MICHAEL J. HATSIOS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MICHAEL J. HATSIOS

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Michael J. Hatsios (he/him/his), and my business address is One
4 Energy Plaza, Detroit, Michigan, 48226. I am employed as Director - Customer
5 Service Operations by DTE Energy Corporate Services, LLC, a subsidiary of DTE
6 Energy.

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company (DTE Electric or Company)?**

10 A2. Yes.

11

12 **Purpose of Testimony**

13 **Q3. What is the purpose of your rebuttal testimony?**

14 A3. The purpose of my testimony is to rebut the following intervenor recommended
15 Customer Information Technology (IT) capital disallowances:

16

17 1. Attorney General (AG) Witness Coppola's recommended \$21.2 million
18 disallowance of the four Customer IT capital projects shown in Exhibit A-12,
19 Schedule B5.7.3 on lines 4, 11, 14, and 18, which includes \$5.8 million in the
20 2024 bridge period and \$15.4 million in the 2025 test period.

21

22 2. AG Witness Coppola's recommendation to remove the \$5.8 million of working
23 capital for the Time-of-Day (TOD) project shown on line 27 of Exhibit A-12,
24 Schedule B4, and \$1.7 million and associated amortization expense from the
25 Company's projected 2023 costs included in the deferred regulatory asset.

Line
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1 3. Soulardarity and We Want Green, Too (collectively, the Detroit Area Advocacy
2 Organization or DAAO) Witness Koeppel's and Witness Jacob's recommended
3 disallowance of \$10.7 million in 2022-2025 IT capital to fund the Collection
4 Digital Self-Service projects. These capital dollars, and the projects with which
5 they are aligned, are summarized at page MJH-21, Table 3 of my revised direct
6 testimony. My rebuttal to the proposed disallowances will also include a
7 response to Witness Koeppel's views on the value of digital self-service
8 investments and to Witness Jacob's opinion about the effectiveness of our
9 digital self-service tools, specifically the DTE Kiosks and automated messages,
10 in serving low-income customers. I will also provide a response to Witness
11 Jacob on the importance of DTE Electric offering phone service to low-income
12 and vulnerable customers.

13
14 I will also be providing responses to certain questions, concerns, and assertions that
15 were expressed by the intervenors in Case No. U-21534 related to the following:

16
17 1. DAAO Witness Koeppel's assertion that there has been a significant increase
18 in the Company's request for IT capital recovery in the instant case.

19
20 2. Michigan Energy Innovation Business Council, the Institute for Energy
21 Innovation and Advanced Energy United, collectively referred to as MEIU,
22 Witness Barnes' recommendations related to the timing of the implementation
23 of Commercial and Industrial Time-of-Use (C/I TOU) rates and supporting
24 analysis tools.
25

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1 3. Michigan Municipal Association for Utility Issues (MI-MAUI) Witness
2 Bunch's concerns regarding the safety of making a payment at a DTE Kiosk
3 and the geographical locations where the kiosks are located.
4

5 Finally, I will be providing a response to Michigan Public Service Commission
6 (MPSC or Commission) Staff (Staff) Witness Klocke's request that DTE Electric
7 further describe and provide regular updates to Staff and the Commission regarding
8 its on-going efforts to improve the outage customer experience and achieve the
9 long-term goals for key performance metrics as part of the Error Free
10 Communications (EFC) – Outage Status project.
11

12 The absence of a discussion of any other matters not listed above, and not included
13 in my rebuttal testimony, should not be taken as an indication of agreement with
14 other aspects of any witness's testimony in the instant case.
15

16 **Q4. Are you sponsoring any exhibits in this proceeding?**

17 A4. Yes, I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-44	II1	2024 – 2025 Collection Self-Service Enhancements

20

21 **Q5. Was the exhibit prepared by you or under your direction?**

22 A5. Yes, it was.
23

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No.

1 **Attorney General (AG) - IT Project Capital Disallowances**

2 **Q6. What disallowances does AG Witness Coppola recommend with respect to the**
3 **Company's Customer IT capital projects?**

4 A6. AG Witness Coppola at page 47, lines 1 through 18 at page 48, and lines 1 through
5 2 of his direct testimony, recommends disallowances of \$5.8 million and \$15.4
6 million for forecasted 2024 and 2025 capital expenditures, respectively, for four
7 Customer IT capital projects. The four projects explicitly recommended for
8 disallowance in Witness Coppola's direct testimony include the three Michigan
9 Green Power (MIGP) projects shown in Exhibit A-12, Schedule B5.7.3, on lines 4,
10 11, and 15, and the 2025 Advanced Analytics (AA) Use Case for Reducing MPSC
11 Complaints, which represents \$1.0 million of the total \$3.0 million in capital for
12 the 2025 AA Use Cases Implementation project in Exhibit A-12, Schedule B5.7.3,
13 on line 18.

14
15 Witness Coppola is also recommending at page 64, lines 15 through 17 of his direct
16 testimony the reduction of \$5.8 million in TOD working capital, and \$1.7 million
17 in amortization expense, related to the TOD Deferred Asset as calculated in Exhibit
18 A-13, Schedule C5.9.3.

19

20 **Q7. What is the basis of AG Witness Coppola's proposed disallowance of**
21 **forecasted IT capital expenditures totaling \$21.2 million for four Customer IT**
22 **projects?**

23 A7. The basis for Witness Coppola's recommended disallowance of these four projects
24 is his assertion at page 47, lines 16 through 18 of his direct testimony that "these
25 projects have not yet started the initial scoping phase, are in the early phase of

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1 development, or will not be completed by the end of the projected test year”, and
2 therefore, he maintains that it would be premature to include the forecasted IT
3 capital expenditures in rate base.

4

5 **Q8. What is the basis for AG Witness Coppola’s recommended TOD working**
6 **capital and amortization expense adjustment?**

7 A8. Witness Coppola’s recommended adjustment of the TOD working capital is based
8 on his assertion at page 63, line 19 through page 64, line 8 of his direct testimony
9 that “in neither its filed testimony nor in its exhibit, did the Company provide any
10 evidence that the costs incurred in 2022 and forecasted for 2023 were reasonable
11 and prudent” and that in its response to the AG’s discovery request to provide
12 specific costs incurred over \$100,000, the Company provided “no itemized list of
13 actual costs or calculations as to how it arrived at the forecasted costs”. As such,
14 Witness Coppola is recommending the removal of \$5.8 million in 2023 TOD
15 working capital and the associated \$1.7 million in amortization expense from the
16 Company’s forecasted amounts for the projected test year at page 64, lines 15-17
17 of his direct testimony.

18

19 **Q9. Do you agree with AG Witness Coppola that the capital for the four Customer**
20 **IT projects for which he is recommending disallowance totals \$21.2 million?**

21 A9. No, I do not. As a threshold matter, Witness Coppola has over-stated the 2024 and
22 2025 capital dollars associated with the four IT capital projects for which he is
23 recommending for disallowance. In his direct testimony in Case No. U-21534, at
24 page 47, lines 9 through 14 on, Witness Coppola identifies each of the specific
25 capital projects for which he is recommending a disallowance, which includes: (1)

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1 the MIGP Customer Requested Renewable Energy Project, (2) the MIGP Scope 3
2 Billing and Enrollment project, (3) the Rider 17- MIGreenPower Residential and
3 Commercial project (MIGP Rider 17), and (4) the 2025 Advanced Analytics Use
4 Case for Reducing MPSC Complaints. Witness Coppola states in his direct
5 testimony, and includes in his supporting Exhibit AG-18, line 27, that the capital
6 expenditures for these four projects are \$5.75 million for 2024 and \$15.39 million
7 for 2025. However, the total \$21.2 million in 2024-2025 capital dollars that
8 Witness Coppola is recommending for disallowance for these four projects are not
9 aligned with the actual dollars for which the Company is seeking recovery, as they
10 are reflected in Exhibit A-12, Schedule B5.7.3 or as described in my revised direct
11 testimony.

12
13 Witness Coppola has inadvertently included in his capital totals \$2.00 million for
14 the 2024 Advanced Analytics Use Cases Implementation project (described at page
15 MJH-40, lines 12 through 24 and page MJH-50, line 6 through MJH-51, line 4 of
16 my revised direct testimony), and \$2.01 million in 2025 IT capital for the other
17 2025 Advanced Analytics Use Case described at page MJH-52 lines 2 through 20
18 of my revised direct testimony, neither of which is he recommending for
19 disallowance in his direct testimony. As such, the total capital associated with the
20 projects for which Witness Coppola is recommending for disallowance is \$3.75
21 million in 2024 and \$13.39 million in 2025.

22
23 **Q10. Given your response to Q9, which capital disallowances related to the four**
24 **Customer IT projects are you rebutting?**

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1 A10. I will be rebutting Witness Coppola's proposed disallowance of the \$3.75 million
2 in 2024 IT capital associated with the MIGP Customer Requested Renewable
3 Energy Projects (\$2.25 million) and MIGP Rider 17 project (\$1.50 million), the
4 \$8.49 million in 2025 IT capital associated with the MIGP Customer Requested
5 Renewable Energy Projects (\$5.49 million) and the MIGP Rider 17 project (\$3.00
6 million), and finally, the \$1.00 million in 2025 IT capital associated with the 2025
7 Advanced Analytics Use Case for Reducing MPSC Complaints as it is described at
8 page MJH-51, lines 6 through 25 of my revised direct testimony. I will not be
9 rebutting Witness Coppola's recommended disallowance of the \$3.9 million in
10 2025 IT capital associated with the MIGP Scope 3 Billing and Enrollment project,
11 as this project has been rescheduled to begin in 2026 to align with the go-live dates
12 of new renewable energy generation capacity in 2026, and as such, the Company is
13 withdrawing its request for recovery of this capital in the instant case.

14

15 **Q11. Why are you rebutting AG Witness Coppola's disallowance of the 2024 and**
16 **2025 capital for the MIGP Customer – Requested Renewable Energy Projects**
17 **(Exhibit A-12, Schedule B5.7.3, line 4)?**

18 A11. As described in my revised direct testimony on page MJH-86, line 10 through MJH-
19 87, line 7, the Company is investing \$2.7 million in the 2023-2024 bridge period,
20 and \$5.5 million in the 2025 test period capital in the MIGP Customer-Requested
21 Renewable Energy Projects. The capital requested reflects a variance of \$4.6
22 million less in the 36 months ending December 31, 2024, than what was approved
23 for cost recovery in U-21297 as the project has been pushed out to 2025 due to a
24 delay in the construction of these projects, which is reflected and in alignment with
25 the project timeline provided on page 5 of Exhibit AG-13. The requested capital

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1 for this project represents two unique contracts with two companies to build two
2 dedicated solar parks with 650 MW and 400 MW of capacity, respectively, to offset
3 the customers' electricity use with green energy. Given the prior approval of the
4 project capital in Case No. U-21297 as a Level 2 project (MPSC Staff Exhibit S-
5 12.3, page 1, line 40) and the contracted nature of these projects, the Company is
6 mandated and committed to make these investments. Thus, the Commission should
7 reject the AG's proposed disallowance of \$7.7 million in 2024 bridge and 2025 test
8 period capital.

9
10 In regard to Witness Coppola's assertion that the project either has not started, is in
11 the early phase of development, or will not be completed by the end of the projected
12 test year, I would point out that the 2024-2025 project kicked-off on August 1,
13 2024, is in the project initiation phase and progressing per the timetable provided
14 on page 5 of Exhibit AG-13, and is on track to go-live by November 30, 2025. 2024
15 year-to-date capital spend is \$2.0 thousand, and year-end forecasted costs are \$2.3
16 million. There is no change to the 2025 projected test period capital of \$5.5 million.

17
18 **Q12. Why are you rebutting AG Witness Coppola's proposed disallowance of the**
19 **2024 and 2025 capital for the Rider 17 – MIGP, Residential and Small**
20 **Commercial & Industrial Project (Exhibit A-12, Schedule B5.7.3, line 15)?**

21 A12. As described in my revised direct testimony on page MJH-90, lines 8 through 22,
22 the Company is investing \$1.9 million in the 2023-2024 bridge period and \$3.0
23 million in the 2025 test period capital in the Rider 17 – MIGreenPower, Residential,
24 Small Commercial, and Industrial project. This capital reflects a variance of \$1.9
25 million less in the 24 months ending December 31, 2024, than was approved for

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1 cost recovery in Case No. U-21297. This is because the planned work could not
2 start until after the Commission approved the project in November 2023. Given
3 the regulatory nature of this project and the prior approval of the project capital in
4 Case No. U-21297 as a Level 2 project (MPSC Staff Exhibit S-12.3, page 1, line
5 39), the Company is mandated and committed to make these investments; hence,
6 the Commission should reject the AG's proposed disallowance of \$4.5 million in
7 2024 bridge and 2025 test period capital.

8

9 Regarding Witness Coppola's assertion that the project either has not started, is in
10 the early phase of development, or will not be completed by the end of the projected
11 test year, the 2024 project kicked-off in February 2024 and is in the first Testing
12 phase with Development continuing and additional Testing to come. Thus, it is not
13 pre-mature to request recovery for this project. We are progressing per the timetable
14 to go-live by November 30, 2024, and have spent \$0.4 million in 2024 year-to-date
15 capital and are forecasting to spend \$1.5 million by year-end.

16

17 Also, while the Company provided project phases and associated timeline for the
18 2024 and 2025 projects separately in our discovery response to the AG, as shown
19 on page 5 of Exhibit AG-13, this project is essentially one multi-year project with
20 annual releases of system enhancements based on customer demand for renewable
21 energy and energy market pricing. Thus, the 2025 project is not a stand-alone
22 project, and hence the project is well beyond the initial design or early development
23 stage of maturity. The 2025 project phase will start in January 2025, as reflected on
24 page 5 of Exhibit AG-23, which aligns with when annual funding of IT capital is

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1 available. There is no change to the go-live date by November 30, 2025, or in the
2 2025 projected test period capital of \$3.0 million.

3

4 **Q13. Why are you rebutting Witness Coppola's disallowance of the 2025 IT capital**
5 **for the Advanced Analytics Use Case for Reducing MPSC Complaints**
6 **project?**

7 A13. As described in my revised direct testimony at page MJH-51, lines 6 through 25,
8 the Company is investing \$1.0 million in capital in the 2025 Advanced Analytics
9 Use Case for Reducing MPSC complaints. This use case will leverage machine
10 learning to model and better understand the drivers of customer MPSC Complaints,
11 with an emphasis on the Billing and Collection transactions, which generate ~80%
12 of the total Customer Service MPSC Complaints. In addition to reducing MPSC
13 Complaints by 15% over a five-year period starting in 2026 through proactive
14 customer outreach, it will also improve the visibility for customer representatives
15 (CRs) in the Contact Center to use the information provided by the model to better
16 manage customer inquiries and provide higher quality service.

17

18 In regard to Witness Coppola's assertion that the project either has not started, is in
19 the early phase of development, or will not be completed by the end of the projected
20 test year, I would point out that, as provided on pages 4 through 5 of Exhibit AG-
21 13, the 2025 Advanced Analytics Use Case to reduce MPSC Complaints project is
22 on track to start in March 2025, which aligns with when analytics resources would
23 be available to start this project, with no change to the go-live date by December
24 12, 2025, or in the 2025 projected test period capital of \$1.0 million. Furthermore,
25 initial scoping has been completed and data preparation to bring complaints data

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1 into our DTE cloud platform is underway. Due to the extensive data and data
2 engineering requirements of the project, work has begun in 2024 to ensure the
3 timely kick-off of the modeling phase of the project in March 2025.

4

5 **Q14. Do you agree with AG Witness Coppola's recommendation to remove the**
6 **\$5.8 million in 2023 TOD working capital and the associated \$1.7 million in**
7 **amortization expense?**

8 A14. No, I do not. In Case No. U-21297, the Company provided the projected cost for
9 the TOD project to be \$2.4 million in 2022 and \$6.1 million in 2023, for a total cost
10 of \$8.5 million for the deferred asset. The final order in Case No. U-21297
11 approved the working capital and the related \$1.7 million in amortization expense.

12

13 In the instant case, the Company provided the actual costs of \$2.0 million for 2022
14 and projected cost of \$6.5 million for 2023, for a total of \$8.5 million, resulting in
15 the amortization of \$1.7 million per year. On an overall basis, there was minimal
16 change in the total 2022 and 2023 TOD project O&M costs.

17

18 Differences in 2022 and 2023 costs between Case No. U-21297 and Case No. U-
19 21534 included reductions or offsets across Information Technology (IT),
20 Customer Outreach and Customer Service. The 2022 variance between actual costs
21 in Case No. U-21534 and projected costs in Case No. U-21297 involved a reduction
22 in all three TOD expense line items, resulting in a \$0.4 million reduction after
23 accounting for TOD expenses prior to November 18, 2022. Projected costs for
24 2023 in Case No. U-21534 increased by \$0.4 million in total, largely due to
25 Customer Service overtime labor that was partially offset by a decrease in IT and

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1 Customer Outreach spending. The Customer Service overtime labor costs were
2 required to perform billing and AMI meter rate conversion pre-work, manual
3 intervention of placing customers on the new TOD rates, and for processing
4 business exceptions related to delayed bills. Overall, there was essentially no
5 variance in the total TOD costs of \$8.5 million, that was approved for deferral in
6 Case No. U-21297, and therefore, the Commission should reject the AG's
7 disallowance of \$5.8 million on working capital and the associated amortization
8 expense of \$1.7 million.

9

10 **Detroit Area Advocacy Organization (DAAO) - IT Project Capital Disallowances**

11 **Q15. What are DAAO Witness Koeppel's concerns about investments in digital self-**
12 **service programs, and particularly regarding Collection Self-Service?**

13 A15. On page 29, line 10 through page 31, line 2 of Witness Koeppel's direct testimony,
14 he raised several concerns regarding the Company's investment in digital self-
15 service solutions, especially regarding Collection Digital Self-Service. What
16 follows is a summary of Witness Koeppel's concerns:

17

18 1. Witness Koeppel asserts that DTE Electric's proposed IT investments in digital
19 self-service tools for customer collections may be subject to diminishing returns
20 and may not generate the full scale of benefits that the company claims (at page
21 29, lines 11 through 14).

22

23 2. Witness Koeppel asserts that DTE Electric's self-service options may be
24 reaching a saturation point in terms of adoption and utilization since 69% of
25 customer transactions were completed in a digital channel in 2023 as compared

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1 with 53% in 2020, and for the Outage and Payment transactions, they are
2 nearing their long-term digital engagement rate (DER) targets (at page 29, line
3 15 through page 30, line 4).

4

5 3. While Witness Koeppel acknowledges that Collection DER is increasing, he
6 maintains that Collection call volumes are not diminishing (at page 30, lines 4
7 through 5).

8

9 4. Witness Koeppel asserts that the Company's investments in Collection Digital
10 Self-Service do not align with the Commission and other stakeholders' goals of
11 advancing energy affordability, equity, and sustainability (at page 30, lines 6
12 through 9).

13

14 **Q16. How do you respond to DAAO Witness Koeppel's concerns about the**
15 **Company's investments in Collection Digital Self-Service?**

16 A16. The Company rejects each of Witness Koeppel's assertions. What follows are the
17 reasons for the Company's rejection of those assertions:

18 1. The Company rejects Witness Koeppel's assertion that it is seeing diminishing
19 returns from its digital self-service investments and may not generate the full
20 scale of benefits the Company claims. By 2027, the Company is forecasting to
21 reach an overall average DER of 76% across key customer transactions (see
22 Digital Engagement Rate (DER) by Transaction on page 1 of Exhibit A-24
23 Schedule N5, lines 8 through 13, columns (c and d)), which is 7% above the
24 2023 overall DER of 69%. Furthermore, the Company is committing to, as a
25 result of DER increases from 2023-2027, a total of \$9.7 million in 2022-2025

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1 call volume reduction savings, which the Company has removed the DTE
2 Electric portion of \$6.4 million from its requested O&M cost recovery as
3 discussed at page MJH-20, lines 7 through 15 of my revised direct testimony
4 and as shown in Exhibit A-24, Schedule N5, page 1, line 17, column (f), and
5 Exhibit A-13, Schedule C5.7, line 5, column (k). The Company has also
6 committed to removing these call volume reduction savings in future rate cases,
7 providing total cumulative 2022-2027 O&M cost savings of \$15.7 million as
8 shown in Exhibit A-24, Schedule N5, page 1, line 16, column (h).

9

10 2. The Company also rejects Witness Koeppel's assertion that it is reaching a
11 saturation point in customer adoption and utilization of its digital self-service
12 solutions. Although Witness Koeppel is correct that Outage DER is high at
13 94% and 96% in 2022 and 2023, respectively, and hovering near the 2027 DER
14 target of 95%, the Outage DER varies year-over-year based on the volume of
15 storm activity. Regarding Witness Koeppel's comment about Payment DER
16 also nearing its 2027 target of 85% given it reached 84% DER in 2023, a 1%
17 increase in Payment DER is not the same as a 1% increase in the other
18 transactions as our customers make nearly 33 million payments per year, so a
19 1% increase by 2027 is an ambitious goal.

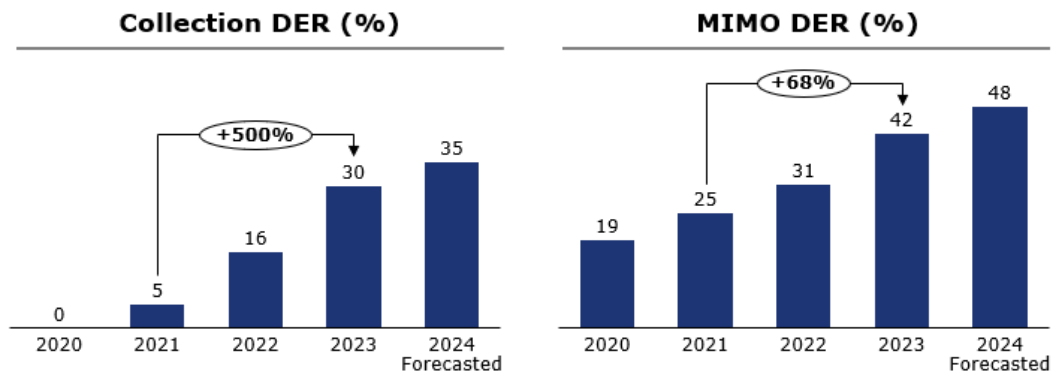
20

21 Furthermore, as seen in Figure 1 below, the Company has seen rapid growth in
22 Collection DER from 2021 to 2023 and how that compares with what we saw
23 over the same period with the Move-in / Move-out (MIMO) transaction, which
24 has also experienced significant DER growth. Adoption of the Collection self-
25 service tools has been much faster and coincides with making Collection self-

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service options (e.g., Restore Electric Service and Payment Extension) available to customers. Also, it is worth noting that the Company has seen rapid adoption of the newly launched (June 2024) Web Payment Agreement (PA) solution, which has already resulted in 7,600 customer PA enrollments (equivalent to 12% of all PA enrollments to-date in 2024). And despite these recent significant increases in both the Collection and MIMO DERs, both transactions remain well below their long-term targets of 60%, as shown in Table 2 at page MJH-18 of my revised direct testimony in the instant case.

Figure 1: 2020-2024 Growth in Digital Engagement



- The Company rejects Witness Koeppel's assertion that the Collection Digital Self-Service solutions are not contributing to a reduction in call volumes. As described in my revised direct testimony at page MJH-23, lines 3 through 9, in 2023, despite increased numbers of low-income customers, increased numbers of low-income customers entering final arrears, and reduced energy assistance funding, the Company handled 43,500 fewer Collection calls than it did in 2022. This was a direct result of the continued expansion and enhancement of the Company's Collection Digital Self-Service solutions, with customers

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1 increasing their use of these digital solutions from 16% in 2022 to 30% in 2023
2 and 35% year-to-date for 2024, as shown in Figure 1.

3

4 Furthermore, in 2024, we are forecasting to reduce Collection call volume by
5 133,000 calls, having already realized a year-to-date reduction of 77,000 calls.
6 This will bring the total cumulative reduction in call volumes from 2023-2024
7 to 176,500 calls, which is ~50% of the 343,600 cumulative Collection calls we
8 projected to reduce from 2023-2027, providing \$2.0 million in cumulative
9 O&M savings. See annual and cumulative 2023-2027 Collection call volume
10 reduction actuals and projections and associated O&M savings as provided at
11 page 2 of Exhibit A-24, Schedule N5, lines 10 and 18.

12

13 4. Finally, the Company disputes Witness Koppel's assertion that its investments
14 in Collection Digital Self-Service solutions are not aligned with the
15 Commission and other stakeholder goals of improving affordability, equity, and
16 sustainability. The Company maintains that it is providing equitable
17 opportunities for low-income and other vulnerable customers to have access to,
18 and the same opportunity to choose to engage in, the same convenient and easy-
19 to-use Digital Self-Service solutions as any other customer who finds
20 themselves struggling to pay or in some step of the Collection process.
21 Furthermore, as outlined in my revised direct testimony at page MJH-23, lines
22 18 through 24 in the instant case, the realized and forecasted Collection call
23 volume reductions are forecasted to deliver \$3.9 million in cumulative O&M
24 savings from 2023-2027, summarized in Exhibit A-24, Schedule N5, page 1,
25 line 3, column (j). These O&M savings are part of the total \$9.7 million in

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1 2022-2025 call volume reduction savings for which the Company has removed
2 the DTE Electric portion of \$6.4 million from its requested O&M cost recovery
3 as discussed above and at page MJH-20, lines 7 through 15 of my revised direct
4 testimony and as shown on Exhibit A-13, Schedule C5.7, line 5, column (k).
5 Therefore, not only is the Company providing low-income, vulnerable, and
6 other customers with the tools they need to reduce their past-due balances and
7 avoid shut-off, but it is also providing significant O&M savings, which are
8 passed on to all customers through the rate-making process.

9

10 **Q17. What specific aspects of DAAO Witness Koeppel's direct testimony, as it**
11 **relates to his recommended disallowance of the \$10.7 million in IT capital for**
12 **Collection Digital Self-Service, are you rebutting?**

13 A17. I will rebut Witness Koeppel's assertion in his direct testimony at page 31, line 17
14 through page 32, line 8 that the Company's justification for the \$10.7 million capital
15 investment in Collection self-service prioritizes its own financial interests (through
16 earning a return on invested capital) over the needs and well-being of its customers
17 despite being aware of the energy affordability challenges that some of its
18 customers face, and are using ratepayer funds to make its collections process "more
19 automated, efficient and aggressive," and easier for the Company to pursue
20 collections and disconnections. I will also rebut Witness Koeppel's assertion at
21 page 32, lines 12 through 18 of his direct testimony that the Company is more
22 focused on collection efficiency rather than affordability and assistance, which
23 exacerbates the economic and social inequities faced by low-income and
24 marginalized customers and the disproportionate impacts of energy insecurity and
25 utility shut-offs affecting them.

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2

Additionally, it is important to accurately set the context for evaluating the

3

Company's \$10.7 million in capital expenditures in the Collection Digital Self-

4

Service projects. Contrary to what Witness Koeppel claims at page 29, lines 4

5

through 8 of his direct testimony, Customer IT capital investments in Case No. U-

6

21534, for which my direct testimony supports, have not significantly increased but

7

have decreased since the last DTE Electric rate case filing in Case No. U-21297.

8

There is also an error in Witness Koeppel's calculation for which I will discuss and

9

rebut in a later section of my rebuttal testimony.

10

11

Q18. How do you respond to DAAO Witness Koeppel's assertion that the \$10.7 million in Collection Digital Self-Service capital should be disallowed for the reasons described in his direct testimony?

12

13

14

A18. The Company firmly rejects Witness Koeppel's assertion that its investments in

15

Collection Digital Self-Service solutions prioritize the Company's financial

16

interests above the needs of its customers and that these solutions allow the

17

Company to pursue collections and disconnects more easily. The Company has

18

designed every one of its implemented and planned Collection Digital Self-Service

19

solutions with the needs of customers top-of-mind and not to improve the efficiency

20

and convenience of the collection process for the Company, starting with the

21

transactions themselves which make it easier for customers to restore their electric

22

service with full payment of their past-due balance (which represents the majority

23

of all restore electric service orders), request a payment extension to have more

24

time to pay their bill, enroll in a payment agreement to pay their past-due balance

25

over time, or look into their eligibility for energy assistance. These actions may all

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1 be accomplished without human intervention, in a digital channel of their choice
2 and at a time that is most convenient for them, which for some customers is a more
3 comfortable way to interact. And, if the customer prefers, they can call our Contact
4 Center and speak with a customer representative (CR) to handle their Collection
5 inquiry or request.

6
7 In no way has the Company's standard collection or disconnect policies and
8 practices changed between a transaction that is handled digitally or through a call.
9 Through its Digital Self-Service investments, DTE Electric is expanding the ways
10 that customers can interact with the Company to complete their collection
11 transaction and not limiting or prioritizing one channel over another. As more
12 features and functionality are added to the Digital Self-Service channel, customers
13 choose which channel best meets their needs. The Company's investments in
14 Digital Self-Service do not signal a focus on collections efficiency rather than
15 affordability and assistance. I specifically discuss in my revised direct testimony at
16 page MJH-22, lines 18 through 19 and lines 22 through 24, expanding the restore
17 electric service and payment extension eligibility to include more customers and
18 that the Company will be providing new online assistance tools that will guide
19 customers who are having difficulty paying their bill to the most appropriate
20 payment solutions and sources of energy assistance, as part of the 2024-2025
21 Collection digital improvements. See Exhibit A44, Schedule II1 in which I provide
22 more details regarding these digital improvements and their customer benefits. The
23 rapid growth in Collection digital engagement by customers is evidence that
24 customers see value in these technologies, and they meet their needs.

25

Line
No.

1 **Q19. Does DAAO Witness Koepfel acknowledge value in DTE Electric's**
2 **investments in digital self-service? Do you agree with him that digital self-**
3 **service should be complementary to call support?**

4 A19. Yes, he does acknowledge such value. Witness Koepfel says in his direct testimony
5 at page 33, lines 2 through 3 that he thinks improving these [digital] systems is
6 beneficial to customers; however, he doubts they will generate the call volume
7 reductions the Company claims. Given that he expects affordability issues for
8 customers will increase, Witness Koepfel asserts that digital self-service should be
9 considered complementary to call support, at page 33, lines 4 through 8 of his direct
10 testimony. As expressed throughout my rebuttal testimony, the Company agrees
11 that digital self-service is complementary to the support provided by our Contact
12 Center. By 2027, even with our projected call volume reductions, we still expect to
13 handle 2.7 million calls annually, 945,000 or 35% of which will be Collection calls,
14 as shown in Exhibit A-24, Schedule N5, on page 1, line 3, column (e). Thus, the
15 Company is not planning to de-prioritize or no longer answer calls. Customers can
16 always choose to contact the Contact Center and speak to a CR if they are
17 uncomfortable using a digital solution, do not have access to a computer or the
18 internet, or simply prefer to talk to somebody to manage their Collection inquiry or
19 request. Regarding Witness Koepfel's doubts about the Company achieving its
20 projected call volume reductions, as I provided earlier, we are forecasting to reduce
21 133,000 Collection calls in 2024, which is higher than the projected reduction of
22 125,089 calls for 2024 and 2025 combined, as shown Exhibit A-24, Schedule N5,
23 page 2, line 10, columns (k) and (l).

24

Line
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1 **Q20. What specific aspects of DAAO Witness Jacob's testimony, as it relates to**
2 **digital self-service and her recommended disallowance of the \$10.7 million in**
3 **Collection Digital Self-Service capital, are you rebutting?**

4 A20. The reasons for Witness Jacob's recommended disallowance of the \$10.7 million
5 in capital for Collection Digital Self-Service projects at page 21, lines 1 through 8,
6 page 23, lines 1 through 7, page 26, lines 1 through 8, and page 30, lines 1 through
7 22 of her direct testimony, are substantially the same as those of DAAO Witness
8 Koeppel. As such, my rebuttal to her arguments and assertions are the same as
9 those I provided to Witness Koeppel's arguments and assertions.

10

11 **Q21. What do you recommend to the Commission regarding DAAO Witnesses**
12 **Koeppel's and Jacob's recommended \$10.7 million in disallowance for**
13 **Collection Digital Self-Service projects?**

14 A21. I recommend the Commission to not adopt Witnesses Koeppel's and Jacob's
15 proposals to disallow \$10.7 million in capital for Collection Digital Self-Service
16 projects. The Company maintains that its Collection Digital Self-Service
17 investments are beneficial to customers, satisfy the needs of customers who choose
18 to engage in a digital self-service solution, and provide substantial savings that are
19 passed on to all customers through the rate-making process. All of these points are
20 discussed earlier in my rebuttal testimony, outlined in my revised direct testimony
21 at page MJH-20, line 17 through MJH-24 line 17, and supported by Exhibits A-24,
22 Schedule N5 and A-44 Schedule II1 in the instant case.

23

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1 **Q22. Has DAAO Witness Jacob sufficiently demonstrated that DTE’s digital self-**
2 **service tools, specifically the DTE Kiosks and automated messages, are**
3 **ineffective?**

4 A22. No, she has not. Witness Jacob uses DTE Kiosks and automated messages as
5 examples of the ineffectiveness of the Company’s digital self-service tools. Kiosks
6 are mostly considered a Payment Digital Tool due to the self-service capability it
7 provides for customers to make a payment as compared with payments that used to
8 be taken in person by “tellers” at DTE customer offices, which have since all
9 closed. DTE does not charge a fee for using its kiosk, contrary to Witness Jacob’s
10 direct testimony at page 19, lines 1 through 3. The kiosk upgrade referenced by
11 Witness Jacob at page 19, lines 3 through 6 of her direct testimony was categorized
12 as a Collection vs. Payment enhancement as it enabled the kiosks to accept
13 payments from customers who were disconnected due to non-payment and seeking
14 to restore service by displaying the full amount of payment due, including
15 reconnection fees and security deposits, if applicable. It is unclear how the fee-free
16 kiosks and a kiosk enhancement that allows customers who want to restore service
17 would cause low- or non-low-income customers more suffering from collections
18 and affordability issues or make it more difficult and burdensome to make a
19 payment as argued by Witness Jacob at page 19, lines 6 through 11 of her direct
20 testimony. The kiosk example does not illustrate how DTE Electric’s investments
21 in digital self-service have negatively affected low-income customers. I provide a
22 better representation of the types of Collection Digital Self-Service enhancements
23 that the Company is making, and the customer benefits they deliver in Exhibit A-
24 44, Schedule II and in my revised direct testimony at page MJH-22, lines 2 through
25 24.

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1 At page 19, line 18 through page 20, line 4 of her direct testimony, Witness Jacob
2 cites an instance when an automated message that notified newly verified low-
3 income customers to contact the Michigan Department of Health and Human
4 Services (MDHHS) for assistance in paying their DTE bill after state funding had
5 been exhausted on June 14, 2024, as an example of how the Company's digital self-
6 service tools provide outdated or inaccurate information. While the Company
7 strives to accurately communicate information to our customers and regrets any
8 confusion caused by its automated messages, this is a poor example for attempting
9 to show that the Company has fallen short with its digital investments. It was an
10 unanticipated, unique situation that state energy assistance funding had exhausted
11 3.5 months before the end of the fiscal year, and hence, reasonable that the
12 Company's automated messages may not have yet been updated.

13

14 Witness Jacob also raises some concerns related to the Company's Shut-off
15 Protection Plan (SPP) and Cash Only policies and processes in her direct testimony,
16 these topics will be addressed by Company Witness Jason Sparks on page 15 in his
17 rebuttal testimony.

18

19 **Q23. DAAO Witness Jacob says it is important for DTE to offer phone service to**
20 **customers undergoing affordability and collection issues at page 15, lines 1-6**
21 **of her direct testimony. Do you agree?**

22 A23. Yes, I agree, and want to reiterate that DTE's Contact Center will continue to
23 answer customer phone calls even as we enhance our digital self-service channels
24 and grow digital engagement. The Company expects to handle 2.7 million calls
25 overall, including 945,000 Collection calls, annually after reaching our 2027 call

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1 volume reduction goals, as shown in Exhibit A-24, Schedule N5, on page 1, line 3,
2 column (e). As previously emphasized, the Company is not planning to de-prioritize
3 or no longer answer customer calls. In response to Witness Jacob's concerns about
4 the lack of technological or digital literacy among many low-income or vulnerable
5 customers at page 17, line 22 through page 18, line 5 of her direct testimony,
6 customers can always choose at any time to contact the DTE Contact Center and
7 speak to a CR, if they are uncomfortable or unfamiliar with using a digital solution,
8 do not have access to a computer or the internet, or simply prefer to talk to
9 somebody to manage their Collection inquiry or request. We also anticipate that
10 customers will use the digital channels to self-serve simpler transactions and call
11 the Contact Center if they have more complex issues or requests to resolve. By
12 deflecting simple transaction calls to the self-serve channels, this will reduce wait
13 times, also a concern raised by Witness Jacob at page 15, lines 12 through 14 of her
14 direct testimony, and allow our CRs to focus on handling more complicated
15 customer requests.

16

17 **Responses to other Intervenor Questions, Concerns, and Assertions**

18 **Q24. Do you agree with DAAO Witness Koeppel that there has been a significant**
19 **increase in Customer IT capital expenditures being requested for recovery in**
20 **the instant case, for the projects sponsored in your revised direct testimony?**

21 A24. No, I do not. As discussed, my revised direct testimony on page MJH-2 line 22
22 through MJH-3, line 6 supports the reasonableness and prudence of Customer IT
23 capital expenditures in the amount of \$62.1 million for 2022 historical year ended
24 December 31, 2022, \$74.6 million in the projected bridge period (for the 24 months
25 ending December 31, 2024), and \$33.0 million for the projected test year period

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1 ending December 31, 2025, totaling \$169.7 million, as shown in Exhibit A-12,
2 Schedule B5.7.3, line 50 in the instant case. The \$181.1 million in IT capital
3 expenditures referenced by Witness Koeppel, at page 29, lines 4 through 8 of his
4 direct testimony, includes the \$169.7 million but erroneously includes \$11.4
5 million in historical IT capital expenditures, at page MJH-3, lines 7 through 11, of
6 which \$5.7 million is 2021 capital that was previously approved for recovery in
7 Case No. U-20836 and \$5.7 million in 2022-2023 capital already included in the
8 \$62.1 million and \$74.6 million above. Also, when comparing the amount of IT
9 capital expenditures between Case No. U-21297 and Case No. U-21534 for over-
10 lapping years (2022-2024) covered in both rate cases, Customer Service IT capital
11 expenditures requested for recovery have decreased by 12.6% from \$156.4 million
12 to \$136.7 million.

13

14 **Q25. MEIU Witness Barnes is inquiring about Commercial and Industrial TOU**
15 **Rate (C/I TOU) Implementation Timing and Tools, what would be the**
16 **Company's response to his request?**

17 A25. Witness Barnes in his direct testimony in Case No. U-21534 is recommending
18 approval of a C/I TOU rates with five proposed modifications, as discussed at page
19 4, line 19 through page 5, line 10 of his direct testimony. Included in his proposed
20 modifications (#4 and #5) were to add a requirement that any approved C/I TOU
21 rates be made available to customers within three months of the Commission's final
22 order in Case No. U-21534, and that at the same time DTE Electric should provide
23 a C/I TOU rate modeling tool that produces standardized reports for customers.
24 Witness Barnes also discusses the three-month timing of his recommendations for
25 making the C/I TOU rates available to customers at page 25, lines 4 through 10,

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1 and for making the rate comparison reports available at page 28, lines 13 through
2 22 of his direct testimony. Absent a final order in this case, it is premature to
3 commit to completing this work within three months of the final order. The actual
4 implementation timing will be wholly dependent on the specific details of the
5 approved rate, which will likely require significant modifications to our Customer
6 Relationship and Billing (CR&B) back-end and front-end systems, customer-facing
7 channels such as the web, system integrations, and reporting. As such, at this time
8 the Company would maintain that more than three months will be required to
9 responsibly complete all the necessary design, development and testing activities,
10 to ensure that customers are able to seamlessly transition to the new rate.

11

12 **Q26. Is MI-MAUI Witness Bunch correct that there are safety concerns for**
13 **customers making a payment at a DTE Kiosk?**

14 A26. No, he is not. The Company maintains that making a payment at a DTE Kiosk is a
15 safe, secure way for customers to make a cash or check payment. Witness Bunch
16 drew the wrong conclusion that there is a “real and not merely perceived” risk of
17 robbery for customers making a payment at a DTE Kiosk at page 12, lines 4 through
18 7 of his direct testimony based on his interpretation of the Company’s responses to
19 a discovery question in Exhibit MAU-9. As provided in our response, numerous
20 kiosks were damaged due to theft activity and taken out of service in 2023. To our
21 knowledge and based on what we can share of these theft investigations, the
22 instances of kiosk theft in 2023 were specifically directed at the kiosks themselves
23 and typically occurred when there was no one around to prevent the theft. Some
24 kiosks were also removed at some locations per the request of store owners as a
25 “precaution” and not because there had been an incident of robbery or theft at their

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1 location. The Company, of course, takes seriously the safety of our customers and
2 yet disagrees with Witness Bunch that we should warn customers who may be
3 making a cash payment at a kiosk about the theft activity at page 12, lines 13
4 through 16 of his direct testimony. Based on our understanding of the situations
5 surrounding these kiosk thefts, a warning to customers making a payment at a kiosk
6 was not warranted.

7

8 **Q27. MI-MAUI Witness Bunch also raises concerns about the geographic**
9 **distribution of the kiosks in his direct testimony at page 13, line 14 through**
10 **page 14, line 1, is there a reason why they are mostly located in Detroit and a**
11 **few nearby suburbs?**

12 A27. The DTE Kiosks were historically placed in or near customer offices where
13 customers made payments for their DTE bill in person, providing a self-service
14 option for customers who did not need to speak to someone about their payment.
15 These offices have since closed and the ability to make payments in the vicinity
16 was replaced by the kiosks. Geographic distribution, size of the community,
17 poverty rates, and the racial makeup of communities are not factors in determining
18 the location of kiosks.

19

20 **Response to MPSC Staff Recommendations for the EFC – Outage Status Project**

21 **Q28. MPSC Staff Witness Klocke requests that DTE Electric further describe and**
22 **provide continual updates to Staff in bi-annual updates and the Commission**
23 **in future rate cases regarding its ongoing efforts to improve the outage**
24 **customer experience. How do you respond?**

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1 A28. The Company appreciates Staff's agreement on the prudence, reasonableness, and
2 worthiness of the capital expenditures related to the EFC project expressed by
3 Witness Klocke at page 3, lines 21 through 23 of her direct testimony. We are also
4 aligned with Staff as it relates to the ongoing improvement of our outage processes,
5 digital channels, and related systems to provide customers with timely and accurate
6 communications related to customer power status, restoration estimates and other
7 status updates and notifications to keep our customers informed during an outage
8 event per Witness Klocke's testimony at page 4, lines 1 through 4. Accordingly,
9 the Company remains committed to achieving our long-term goals related to the
10 key EFC metrics of Power Restoration Accuracy and Timeliness, First Estimate
11 Accuracy, and Outage Notification Delivery, and as requested by Staff per Witness
12 Klocke's direct testimony at page 4, lines 9 through 12, and as described in my
13 revised direct testimony at page MJH-70, line 5 through MJH-73, line 16, and
14 supported by the Company's capital investments in the core and customer-facing
15 EFC systems.

16
17 In future rate cases, we will provide details about our progress, including our
18 continuous improvement efforts and learnings from executing on our customer
19 outage commitments during storms and any impacts due to major project
20 implementations (e.g., ADMS) per Staff's recommendation at page 5, lines 2
21 through 4 and lines 12 through 15 of Witness Klocke's direct testimony. Going
22 forward, the Company will also provide Staff status updates biannually as preferred
23 by Staff or at a cadence that allows us to provide meaningful status updates such as
24 after reaching key EFC milestones or after significant, catastrophic storms, to
25 assure Staff, and the Commission in future rate cases, that the EFC investments are

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1 steadily and reliably improving our customers' outage experience in accordance
2 with Staff's request at page 5, line 20 through page 6, line 2 of Witness Klocke's
3 direct testimony.

4

5 **Q29. Does this conclude your rebuttal testimony?**

6 A29. Yes, it does.

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.)

BRIAN L. HILL

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF BRIAN L. HILL

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed.**

3 A1. My name is Brian L. Hill (he, him, his), and my business address is One Energy
4 Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company
5 (DTE Electric or Company).

6
7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.
10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of this testimony is to rebut certain positions of Attorney General (AG)
14 Witness Coppola, Association of Businesses Advocating Tariff Equity (ABATE)
15 Witness York, Michigan Public Service Commission (MPSC or Commission) Staff
16 (Staff) Witness Duell, and Michigan Environmental Council (MEC), Natural
17 Resource Defense Council (NRDC), Citizens Utility Board of Michigan (CUB)
18 (collectively “CUB-MN”) Witness Denzler, and The City of Ann Arbor (AA)
19 Witness Stults. The absence of a discussion of other matters in my rebuttal
20 testimony should not be taken as an indication of agreement with other aspects of
21 any intervenor’s testimony.

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1 **Q4. Are you sponsoring any exhibits?**

2 A4. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-52	QQ1	U.S. Department of Defense Inflation and Escalation Best Practices for Cost Analysis
A-52	QQ2	Discovery Response: U-21534 AGDE-3.93a
A-52	QQ3	Discovery Response: U-21534 AGDE-3.95b-01 Emergent Savings 2024-2025

10 **Q5. Were these exhibits prepared by you or under your direction?**

11 A5. Yes, they were.

13 **Q6. How is your testimony organized?**

14 A6. There are sixteen specific points I will rebut in my testimony, as listed below. A
15 discussion of why the intervenor's recommendations should not be accepted by the
16 Commission follows.

Rebuttal Contents

19	Purpose of Testimony	1
20	Capital Emergent Replacements (Exhibit A-12, Schedule B5.4, page 3)	4
21	Rebuttal Issue 1: AG Witness Coppola's position that it is inappropriate to apply	
22	inflation adjustments to historic years and that nominal historical values should be used	
23	for forecasting.	4
24	Table 1 DOD – Best Practices Handbook Page 44, Figure 5-4	8
25	Rebuttal Issue 2: AG Witness Coppola's disagreement with using blended inflation	
26	rates for future years.	9
27	Rebuttal Issue 3: AG Witness Coppola's assertion that the Company did not perform	
28	an analysis to include significant distribution capital investments savings offsets.	10
29	Rebuttal Issue 4: ABATE Witness York's recommendation to remove 2021 historic	
30	Capital Emergent Replacements from its five-year historical average.....	10

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1	Base Capital – Emergent Replacements and Customer Connections, Relocations and	
2	Other (Exhibit A-12, Schedule B5.4, page 1, lines 1-17)	13
3	Rebuttal Issue 5: ABATE Witness York’s recommendation to adopt Real Chained	
4	GDP Index instead of CPI when calculating inflation.	13
5	Distribution Plant – Customer Connections, Relocations and Other (Exhibit A-12,	
6	Schedule B5.4, page 4)	15
7	Rebuttal Issue 6: AG Witness Coppola’s recommendation to remove historic inflation	
8	adjustments for Electric System Equipment and General Plant, Tools & Equipment and	
9	Miscellaneous.	15
10	Rebuttal Issue 7: AG Witness Coppola’s recommended disallowances for Customer	
11	Connections and New Load due to removing historic inflation calculations and	
12	changes to forecasting methodologies.	18
13	Rebuttal Issue 8: AG Witness Coppola’s recommended disallowances for Customer	
14	Connections and New Load Utility Make Ready (UMR) due to changes to EV	
15	forecasts.	20
16	Rebuttal Issue 9: AG Witness Coppola’s recommended disallowance for the I-375	
17	Relocation Project (Exhibit A-12, Schedule B5.4, page 7, line 37)	21
18	Table 2 I-375 Relocation Forecasts.....	22
19	Portable Generators (Exhibit A-12, Schedule B5.4, page 13, line 28)	23
20	Rebuttal Issue 10: AG Witness Coppola’s recommended disallowance for Portable	
21	Generators.	23
22	Base Capital Programs 2023 Underspend.....	25
23	Rebuttal Issue 11: AG Witness Coppola’s recommended removal of 2023 Base Capital	
24	Programs underspend.	25
25	Capital Emergent Replacements Storm Testimony, Processes, and Reporting.....	26
26	Rebuttal Issue 12: Staff Witness Duell’s recommended changes to testimony.....	26
27	Rebuttal Issue 13: MNSC Witness Denzler’s incorrect statement that field personnel	
28	determining whether to repair or replace assets during storm enables the Company to	
29	take advantage of this new cost share structure.	27
30	Rebuttal Issue 14: MNSC Witness Denzler’s recommendation to develop Storm	
31	performance criteria.	28
32	Contributions in Aid of Construction (CIAC)	29
33	Rebuttal Issue 15: MNSC Witness Denzler’s recommendations regarding CIAC.....	29
34	Rebuttal Issue 16: AA Witness Stults’s recommendation regarding CIAC.	30
35		

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1 **Capital Emergent Replacements (Exhibit A-12, Schedule B5.4, page 3)**

2 Rebuttal Issue 1: AG Witness Coppola's position that it is inappropriate to apply
3 inflation adjustments to historic years and that nominal historical values should be
4 used for forecasting.

5 **Q7. What is AG Witness Coppola's recommendation regarding Capital Emergent**
6 **Replacement programs?**

7 A7. On page 20, lines 12-13, AG Witness Coppola recommends a disallowance of
8 \$24,526,000 for 2024, and \$28,557,000 for 2025 for Capital Emergent
9 Replacements.

10

11 **Q8. Why does AG Witness Coppola make these recommendations?**

12 A8. AG Witness Coppola uses three points to support his recommendation for
13 disallowance:

14

15 1). "Although I agree with using a five-year normalization approach to forecast
16 capital expenditures for future years, it should be done using actual capital
17 expenditures from prior years, not by recasting numbers with additional assumed
18 costs that were not incurred based on prior year inflation adjustments. If any
19 inflation was experienced in those prior years, it is reflected in the actual amounts.
20 It is simply an unsupported fabrication to inflate historical costs to arrive at an
21 adjusted historical base and to then further inflate those costs for future years with
22 projected inflation factors." (page 18, lines 3-9)

23

24 2). "I will also point out that the future inflation rates used by the Company to
25 calculate forecasted Emergent Replacements capital expenditures for 2023, 2024,

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1 and 2025 are blended inflation rates consisting of both the CPI and the Company's
2 internal forecasted wage increases. As discussed in more detail in the O&M
3 Expense - Inflation Adjustment section of my testimony, the Commission has
4 previously rejected the use of blended inflation rates." (page 18, lines 9-14)

5

6 3). "I will also point out that contrary to the directives by the Commission in Case
7 Nos. U-20561 and U-20836, the Company did not provide an analysis in this rate
8 case of the offsetting effects of significant distribution capital investments on
9 inflationary pressures on Emergent Replacements." (page 18, lines 15-18)

10

11 **Q9. Do you agree with AG Witness Coppola's recommendation of not applying**
12 **inflation to historic expenditures?**

13 A9. No. While AG Witness Coppola agrees with the use of the five-year normalization
14 to forecast capital expenditures for future years (page 18, line 3-4 of his direct
15 testimony), the Company does not agree with his recommendation of not using
16 historical inflation adjustments.

17

18 The use of inflation is reasonable and appropriate to adjust past expenditures using
19 CPI (Consumer Price Index) to make them comparable with current dollars when
20 they are being used as the basis for future projections starting in a specific year (in
21 this case, that year is 2022, the historic test year).

22

23 It is not an "unsupported fabrication" to apply inflation to historic years. Rather,
24 the Company is appropriately recognizing the time value of money and bringing
25 historic expenditures to a common denomination (baseline), which in the instant

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1 case is 2022 dollars. This baseline is then used to forecast future capital emergent
2 replacement expenditures.

3
4 Actual historic capital expenditures only include inflation incurred in the years
5 leading up to and during that year. Using 2019 historic capital expenditures as an
6 example, they include inflation incurred from prior years and in 2019. However,
7 for calculating a baseline from which to forecast future emergent replacements it is
8 necessary to adjust the 2019 historic capital expenditures with inflation seen from
9 2019 through 2022. Omitting this adjustment on actual historic emergent
10 replacement expenditures would understate the amount of capital required to do the
11 same scope of work in future years.

12

13 **Q10. Has the Commission remarked on this using historical inflation calculations**
14 **in prior cases?**

15 A10. Yes. In Case No. U-20836 the Commission confirmed that a historic adjustment
16 was reasonable, stating on page 63 of the order dated November 18, 2022: “The
17 Commission agrees with, and finds appropriate, the ALJ’s recommendation for the
18 continued use of the five-year average in determining this category of expenditures,
19 *along with the inflationary adjustment to historical data [emphasis added]*,
20 considering this record and increased climate variability over recent years.”

21

22 Additionally, in Case No. U-21297 the Commission confirmed in its order that a
23 historic inflation adjustment was reasonable, stating “The Commission rejects the
24 Attorney General’s inflationary adjustment and finds that DTE Electric has
25 computed the historic average in a manner consistent with Case Nos. U-20836 and

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1 U-20561. *See*, November 18 order, p. 63; May 8 order, p. 86. Regarding the
2 inflationary adjustment, the Commission further acknowledges this case was filed
3 only two months after the issuance of the November 18 order. However, the
4 directives from that order still stand and the Commission anticipates an analysis of
5 the offsetting effects of significant distribution capital investments on inflationary
6 pressures for this cost category in the company's next filed rate case." (U-21297
7 page 76)

8

9 **Q11. Has the Company researched any third-party documentation supporting its**
10 **methodology to adjust historic years with inflation to derive a baseline to use**
11 **for forecasting future expenditures?**

12 A11. Yes. The Company's practice of adjusting historic years to derive a baseline
13 expressed in current dollar values is consistent with the constant-year method
14 (inflation normalized values) discussed within the December 2021 U.S.
15 Department of Defense Inflation and Escalation Best Practices for Cost Analysis
16 (Exhibit A-52, Schedule QQ1).

17

18 In summary, the U.S. Department of Defense best practices state that:

- 19 • Then-year (historical nominal price) is appropriate for understanding actual
20 historical expenditures incurred;
- 21 • Constant-year (inflation adjusted price) is appropriate for estimating,
22 comparing, or reporting;
- 23 • Constant price (values that exclude inflation and price escalation) is only to be
24 used internally as a modeling technique or to understand historical trends and
25 not to be presented publicly.

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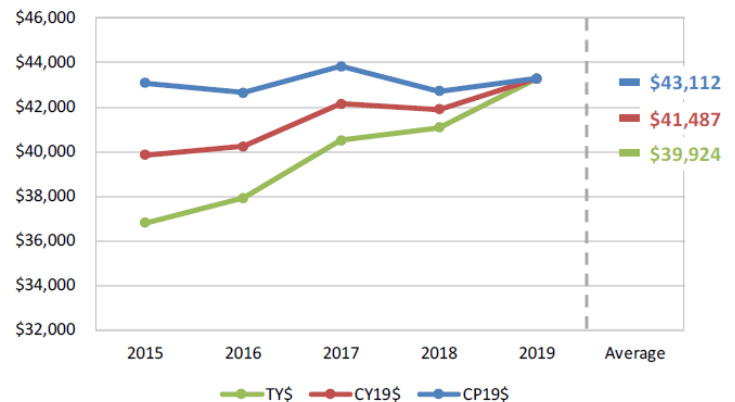
1 **Q12. Does the 2021 United States Department of Defense Inflation and Escalation**
2 **Best Practices for Cost Analysis Handbook (Exhibit A-52, Schedule QQ1)**
3 **provide a visual example?**

4 A12. Yes, page 44 shows an example in Figure 5-4. Calculating average cost factors from
5 historical costs (Table 1).
6

7 **Table 1 DOD – Best Practices Handbook Page 44, Figure 5-4**

Figure 5-4. Calculating average cost factors from historical costs.

Fiscal Year	TY\$	Escalation Index (BY19)	Inflation Index (BY19)	CP19\$ (=TY/esc)	CY19\$ (=TY/inf)
2015	\$ 36,819	0.8548	0.9238	\$ 43,073	\$ 39,854
2016	\$ 37,917	0.8890	0.9423	\$ 42,651	\$ 40,238
2017	\$ 40,518	0.9246	0.9612	\$ 43,824	\$ 42,155
2018	\$ 41,079	0.9615	0.9804	\$ 42,722	\$ 41,901
2019	\$ 43,289	1.0000	1.0000	\$ 43,289	\$ 43,289
Average	\$ 39,924			\$ 43,112	\$ 41,487



8 Page 44 also states, “Out of the three options for averages calculated above, *you*
9 *immediately rule out using the average calculated in TY\$ because it has lost any*
10 *connection to a particular point in time (i.e., the average is a mixture of*
11 *transaction years, and there is no unifying base year for TY\$).*” [emphasis added]
12

13 Please note that the TY\$ approach of using nominal historical dollar values, which
14 is consistent with the approach AG Witness Coppola recommends, is the approach
15 that the U.S. Department of Defense concludes should be immediately ruled out
16 because it does not have a unifying base year (what the Company refers to as a
17 baseline).

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1

2

The Company's approach of using inflation adjusted historic years to determine a baseline from which to forecast future years is consistent with the constant-year (inflation adjusted) methodology which is recommended by the U.S. Department of Defense for estimating, comparing, and reporting.

6

7

Q13. Should the Commission accept AG Witness Coppola's recommended disallowances due to rejecting historic inflation adjustments?

8

9

A13. No. As discussed above, the Commission has approved this methodology in prior cases, and it remains a reasonable and prudent methodology to forecast future expenditures. As explained in the 2021 United States Department of Defense Inflation and Escalation Best Practices for Cost Analysis Handbook (Exhibit A-52, Schedule QQ1), using nominal historic dollar values (transaction-year dollars) as Witness Coppola suggests is inappropriate because they only represent the value of dollars in the year they were spent and do not reflect changes in prices experienced since.

17

18

The Commission should maintain its position from prior cases and reject AG Witness Coppola's recommendation.

19

20

21

Rebuttal Issue 2: AG Witness Coppola's disagreement with using blended inflation rates for future years.

22

23

Q14. Do you agree with AG Witness Coppola's assertion that it is inappropriate to use blended inflation rates for 2023, 2024, and 2025?

24

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1 A14. No. As discussed in Company Witness Foley's rebuttal testimony (reference the
2 Inflation Rate section starting on page NTF-35-Rebuttal), the Company does not
3 agree with Witness Coppola's recommendation to reject the Company's proposed
4 blended inflation rates.

5

6 Rebuttal Issue 3: AG Witness Coppola's assertion that the Company did not perform
7 an analysis to include significant distribution capital investments savings offsets.

8 **Q15. Did the Company perform an analysis that included savings offsets from**
9 **Strategic Capital Investments?**

10 A15. Yes. In Exhibit A-12, Schedule B5.4, page 1, line 6 shows a reduction in Capital
11 Emergent Replacements of \$20,819,951 for 2024 and \$21,435,815 in 2025.

12

13 Further, I explain on page 8, lines 19-24 of my direct testimony that this reduction
14 is due to savings from both Strategic Capital Investments and the Tree Trim Surge
15 program. I state that the reduction calculation is from the analysis performed in the
16 Company's reliability model (as discussed in Company Witness Kryscynski's
17 testimony), which is included in this instant case as WP AJK U-21534 Reliability
18 Model.xlsx (Exhibit A-43, Schedule HH5). These savings calculations were
19 provided in discovery response U-21534 AGDE-3.95b-01 Emergent Savings 2024-
20 2025.xlsx (Exhibit A-52, Schedule QQ3).

21

22 Rebuttal Issue 4: ABATE Witness York's recommendation to remove 2021 historic
23 Capital Emergent Replacements from its five-year historical average.

24 **Q16. What does ABATE Witness York argue concerning historic averages used to**
25 **forecast Capital Emergent Replacements?**

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1 A16. ABATE Witness York on (pages 29 and 30), recommends the adoption of a non-
2 consecutive four-year historic average (2018-2022, excluding 2021) and a resulting
3 disallowance of \$122.822 million for Capital Emergent Replacements.
4

5 **Q17. Why does ABATE Witness York make these recommendations?**

6 A17. On pages 28, lines 11-20 and page 29, lines 1-2, ABATE Witness York states:
7 “While the five-year average has historically been approved by the Commission, it
8 is inappropriate to rely on a five-year average in this case. Specifically, 2021 data
9 should not be included in the historical average, as it was an abnormal year in terms
10 of storm activity. This unprecedented nature of 2021 is also evident from a review
11 of expenditures on storm-related emergent replacements shown on Exhibit A-12,
12 schedule B5.4, page 3. In 2021, these expenditures more than doubled relative to
13 DTE’s annual expenditures from 2018-2020. In 2022, the number of storm days
14 was lower than DTE projected, and there was only one catastrophic storm, which
15 was also lower than the Company’s internal forecast.”
16

17 **Q18. Does the Company agree with ABATE Witness York’s recommended method**
18 **to calculate the level of Capital Emergent Replacements using a four-year non-**
19 **consecutive historical average, and her resultant proposed disallowance?**

20 A18. No. The Company does not agree with using a four-year non-consecutive average.
21 The use of a five-year historic average appropriately accounts for weather
22 variability when forecasting future expenditures for Capital Emergent
23 Replacements. Specifically selecting the highest storm years and then excluding
24 them undermines the intent of a five-year average to account for year-to-year
25 variability in weather.

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1 The Company acknowledged in Case No. U-21297 that the storms in the Summer
2 of 2021 were historic, but that did not imply that severe weather events will never
3 occur again. In fact, as explained in my direct testimony on pages 9-14, in 2023
4 the Company experienced the worst ice storm in its history along with six summer
5 tornadoes resulting in major damage to the electric grid. In total, the Company
6 experienced seven storms in 2023, with two being CAT-1 and three being CAT-2.
7 A CAT-1 storm is defined as 110,000 customers or more without power in a 24-
8 hour period (5% of total customers affected). A CAT-2 storm is defined as 220,000
9 customers or more without power in a 24-hour period (10% of total customers
10 affected).

11

12 **Q19. Has the Commission ruled whether a five-year average is appropriate?**

13 A19. Yes, the five-year forecast has been approved in prior cases U-20162, U-20561, U-
14 20836, and U-21297.

15

16 In Case No. U-20836, the Commission confirmed that a five-year average was
17 appropriate, stating on page 63 of the order dated November 18, 2022: “The
18 Commission agrees with, and finds appropriate, the ALJ’s recommendation for the
19 continued use of the five-year average in determining this category of expenditures,
20 along with the inflationary adjustment to historical data, considering this record and
21 increased climate variability over recent years.”

22 In Case No. U-21297, the Commission again confirmed the usage of a five-year
23 average, stating on page 76 of the order dated December 1, 2023: “Additionally, in

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1 light of the fact that anomalous weather is becoming the norm, the Commission
2 agrees with the ALJ's decision to incorporate all five years in the average. PFD, p.
3 204. As the company notes, 2023 was another anomalous year."

4

5 **Q20. Should the Commission adopt ABATE Witness York's proposed disallowance**
6 **associated with Capital Emergent Replacements?**

7 A20. No. The Commission should reject ABATE Witness York's recommended
8 disallowance of Capital Emergent Replacements expenditures (based on a four-
9 year average excluding 2021). The use of a five-year historic average is the most
10 reasonable and prudent way to forecast future Capital Emergent Replacement
11 expenditures and has been consistently approved by the Commission. The
12 Commission's November 18, 2022 order in Case No. U-20836, noted on page 63:
13 "The Commission agrees with, and finds appropriate, the ALJ's recommendation
14 for the continued use of the five-year average in determining this category of
15 expenditures, along with the inflationary adjustment to historical data, considering
16 this record and increased climate variability over recent years."

17

18 **Base Capital – Emergent Replacements and Customer Connections, Relocations and**
19 **Other (Exhibit A-12, Schedule B5.4, page 1, lines 1-17)**

20 Rebuttal Issue 5: ABATE Witness York's recommendation to adopt Real Chained
21 GDP Index instead of CPI when calculating inflation.

22 **Q21. What is ABATE Witness York's recommendation regarding calculation of**
23 **future levels of base capital?**

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1 A21. ABATE Witness York on page 29 argues that the Company should use GDP
2 Chained Real Price Index rather than CPI inflation rates to project future
3 expenditures (2023-2025) for all base capital categories.

4
5 **Q22. What arguments does ABATE Witness York make regarding changing from**
6 **utilizing CPI to using Real Chained Index?**

7 A22. On page 13, lines 6-18, ABATE Witness York argues that Real GDP Chained Price
8 Index reflects what people are actually buying, is more responsive to customer
9 substitution, and that CPI is heavily weighted by the cost of medical expenses
10 which are not reflective of utility expenses.

11

12 **Q23. Does the Company agree with ABATE Witness York's recommendation to**
13 **change the Company's inflation forecast methodology from CPI to Real**
14 **Chained GDP Index?**

15 A23. No. CPI is the most widely used measure of inflation and for adjusting dollar values
16 for government entities and businesses in the United States. This topic is also
17 discussed in Company Witness Foley's rebuttal testimony.

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Distribution Plant – Customer Connections, Relocations and Other (Exhibit A-12,
Schedule B5.4, page 4)

Rebuttal Issue 6: AG Witness Coppola’s recommendation to remove historic
inflation adjustments for Electric System Equipment and General Plant, Tools &
Equipment and Miscellaneous.

Q24. What is AG Witness Coppola’s recommendation regarding historic inflation
adjustments for Electric System Equipment and General Plant, Tools &
Equipment and Miscellaneous?

A24. AG Witness Coppola proposed disallowances for these expenditures are based on
the same recommendations discussed above in Emergent Replacements. Simply
stated, AG Witness Coppola disagrees with applying inflation to historical years to
calculate future expenditures. As a result of not using historical inflation AG
Witness Coppola proposes the following reductions:

- Electric System Equipment: \$3,153,000 for 2024 and \$3,456,000 for
2025 (page 29, lines 13-15)
- General Plant, Tools & Equipment and Miscellaneous: \$1,758,000 for
2024 and \$1,862,000 for 2025 (page 30, lines 13-16)

Q25. Why does AG Witness Coppola make this recommendation?

A25. AG Witness Coppola’s testimony on page 21, lines 6-13, states “... the Company
applied retroactive historical inflation rates to restate the actual historical number
for the three years from 2019 to 2022, before applying the future inflation rates to
the adjusted three-year historical average spending. This is the same problem
discussed above with Emergent Replacements, where the Company improperly

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1 inflates actual historical capital expenditures to create a larger cost base on which
2 to add future inflation adjustments. Mr. Hill also used this faulty approach to
3 forecast capital expenditures for Relocations, Electric System Equipment, NRUC
4 and Improvements Blankets, and General Plant, Tools & Equipment.”

5

6 **Q26. Do you agree with AG Witness Coppola’s recommendation of not applying**
7 **inflation to historic expenditures?**

8 A26. No. While AG Witness Coppola agrees with the use of the three-year average to
9 forecast capital expenditures for future years (page 21, lines 14-21), the Company
10 disagrees with his recommendation of not using historical inflation adjustments.

11

12 The use of inflation is reasonable and appropriate to adjust past expenditures using
13 CPI (Consumer Price Index) to make them comparable with current dollars when
14 they are being used as the basis for future projections starting in a specific year (in
15 this case, that year is 2022, the historic test year).

16

17 It is not an “unsupported fabrication” to apply inflation to historic years. Rather,
18 the Company is appropriately recognizing the time value of money and bringing
19 historic expenditures to a common denomination (baseline), which in the instant
20 case is 2022 dollars. This baseline is then used to forecast future capital emergent
21 replacement expenditures.

22

23 Historic capital expenditures only include inflation incurred in the years leading up
24 to and during that year. Using 2019 historic capital expenditures as an example, this
25 total includes inflation incurred from prior years and in 2019. However, for

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1 calculating a baseline from which to forecast future emergent replacements it is
2 necessary to adjust the 2019 historic capital expenditures with inflation seen from
3 2019 through 2022. Not performing this adjustment on historic emergent
4 replacement expenditures would understate the amount of capital required to do the
5 same scope of work in future years.

6

7 **Q27. Has the Commission remarked on this using historic inflation adjustments in**
8 **prior cases?**

9 A27. Yes. The Commission has supported the usage of historic inflation adjustments for
10 Capital Emergent Replacements in Case Nos. U-20836 and U-21297 as discussed
11 in Q&A 10 earlier in my rebuttal testimony.

12

13 **Q28. Should the Commission adopt AG Witness Coppola's disallowance due to**
14 **historic inflation adjustments applied to Distribution Plant – Customer**
15 **Connections, Relocations and Other?**

16 A28. No. The Company's application of inflation to prior years is consistent with how it
17 has historically forecasted Capital Emergent Replacements and those forecasts
18 have received Commission approval.

19 Additionally, the Company has presented evidence in Q&As 9-13 in this rebuttal
20 testimony above showing that the Company's methodology of applying historic
21 inflation is consistent with the U.S. Department of Defense best practices.

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1 Rebuttal Issue 7: AG Witness Coppola's recommended disallowances for Customer
2 Connections and New Load due to removing historic inflation calculations and
3 changes to forecasting methodologies.

4 **Q29. What is AG Witness Coppola's recommendation regarding Customer**
5 **Connections and New Load Growth?**

6 A29. There are two separate recommendations AG Witness Coppola makes regarding
7 this category:

8

9 1) AG Witness Coppola's testimony recommends a disallowance of \$14,453,000
10 for 2024 and an increase of \$3,405,000 for 2025 for Customer Connections and
11 New Load Growth on page 24, lines 13-15.

12

13 2) AG Witness Coppola's testimony recommends an additional disallowance of
14 \$3,734,000 in 2024 and \$10,173,000 in 2025 for Customer Connections and
15 New Load that is associated with Utility Make Ready (UMR) projects
16 supporting electric vehicle adoption on page 26, lines 11-12.

17

18 **Q30. Why does AG Witness Coppola make the first recommendation for**
19 **disallowances for Customer Connections and New Load Growth?**

20 A30. On page 24, lines 3-15 of his direct testimony Witness Coppola calculates these
21 disallowance totals by removing Utility Make Ready (UMR) expenditures, then
22 calculating the 2021-2023 average annual expenditures (without historic inflation
23 adjustments), and applying Michigan housing starts forecasts of -3.8% in 2024 and
24 +10.8% in 2025. He then compares his forecasts to those of the Company and
25 proposes the difference between the two as adjustments to this category.

Line
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1 **Q31. Do you agree with AG Witness Coppola’s arguments for disallowances to**
2 **Customer Connections and New Load Growth due to the removal of historic**
3 **inflation adjustments?**

4 A31. No. The reasonableness of using historic inflation adjustments is discussed in
5 Q&As 9-13 in this rebuttal testimony above which shows it is identified as a U.S.
6 Department of Defense best practice for estimating.

7

8 **Q32. Do you agree with AG Witness Coppola’s arguments for disallowances due to**
9 **using Michigan housing starts forecasts rather than the historic three-year**
10 **average for future years?**

11 A32. No. The Company would like to emphasize that this category of expenditures
12 includes activities beyond connecting new homes such as customer requested
13 upgrades, accommodating business development, and resolving circuit loading
14 issues which are not directly tied to residential housing starts.

15

16 **Q33. Should the Commission adopt AG Witness Coppola’s recommended**
17 **disallowances for 2024 and 2025 Customer Connections and New Load**
18 **Growth due to removal of historic inflation adjustments and Michigan housing**
19 **start forecasts?**

20 A33. No. The application of historic inflation adjustments is appropriate, and this
21 category of expenditures includes work that is independent of new home builds.
22 The Company’s methodology of using a three-year inflation adjusted forecast is
23 reasonable and prudent.

Line
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1 Rebuttal Issue 8: AG Witness Coppola's recommended disallowances for Customer
2 Connections and New Load Utility Make Ready (UMR) due to changes to EV
3 forecasts.

4 **Q34. Why does AG Witness Coppola make the second recommendation for**
5 **Customer Connections and New Load disallowances associated with Utility**
6 **Make Ready (UMR) projects?**

7 A34. AG Witness Coppola states on pages 25 and 26:

- 8 • The Company's EV adoption forecast is unrealistic,
- 9 • Customers are unhappy with electric vehicles,
- 10 • Auto manufacturers are shifting from EVs to self-charging hybrids in
- 11 response,
- 12 • It is more appropriate to forecast 2024 and 2025 using 2023 actual
- 13 expenditures plus inflation,
- 14 • A disallowance of \$3,734,000 for 2024 and \$10,173,000 for 2025 are
- 15 therefore justified.

16

17 **Q35. Do you agree with AG Witness Coppola's arguments for disallowances to**
18 **Utility Make Ready (UMR) projects?**

19 A35. No. The Company supports ensuring the distribution grid is ready for EV adoption,
20 consistent with the shift to EVs that are a critical part of the Michigan MI Healthy
21 Climate Plan. This topic is rebutted in detail by Company Witness Bennett
22 (beginning on page PB-8).

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1 Rebuttal Issue 9: AG Witness Coppola’s recommended disallowance for the I-375
2 Relocation Project (Exhibit A-12, Schedule B5.4, page 7, line 37)

3 **Q36. What is AG Witness Coppola’s recommendation regarding the I-375**
4 **Relocation Project?**

5 A36. He recommends disallowances of \$25,000,000 for 2024 and \$8,000,000 for 2025
6 associated with the I-375 Relocation Project (page 28, lines 14-15). These
7 recommended disallowance amounts reflect the entirety of the Company’s
8 requested capital expenditures for the project.

9

10 **Q37. Why does AG Witness Coppola’s recommend a full disallowance for 2024 and**
11 **2025 expenditures for the I-375 Relocation Project?**

12 A37. AG Witness Coppola states on page 28, lines 8-15, “MDOT is known for
13 establishing initial plans and later delaying projects. Although the Company may
14 have done some design and engineering work in 2023 with the \$5.9 million
15 budgeted, it is unlikely that it will spend the \$25 million forecasted for 2024 or the
16 \$8 million forecasted for 2025. It is premature and imprudent to include those large
17 amounts in rate base in this rate case. The Company would be earning a return and
18 recovering depreciation expense for costs that would likely not be incurred.
19 Therefore, I recommend that the Commission remove the \$25 million for 2024 and
20 the \$8 million for 2025 from the Company’s forecasted capital expenditures.”

21

22 **Q38. Do you agree with AG Witness Coppola’s recommendation for a full**
23 **disallowance for 2024 and 2025 expenditures for the I-375 Relocation Project?**

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1 A38. No. The Company has received a notice to vacate from MDOT and must proceed
2 with work. It is not reasonable to expect that the entirety of the project will be
3 delayed and that no work will be performed by the Company in 2024 or 2025.

4

5 The Company's current forecast, as of this testimony, is that \$8,842,825 will be
6 invested for this project in 2024 and that \$13,802,315 will be invested for this
7 project in 2025 (Table 2).

8

9

Table 2 I-375 Relocation Forecasts

I-375 Relocation	2024	2025
Exhibit A-12, Schedule B5.4	\$25,000,000	\$8,000,000
Current DTEE Forecast	\$8,842,825	\$13,802,315
Difference (Lower) / Higher	(\$16,157,175)	\$5,802,315

10

11 **Q39. Should the Commission accept AG Witness Coppola's recommendation to**
12 **disallow all amounts associated with the I-375 Relocation project in 2024 and**
13 **2025?**

14 A39. No. The Company has received a notice to vacate from MDOT and must proceed
15 with work. It is not reasonable to expect that zero work will be completed on the I-
16 375 Relocation project in 2024 and 2025.

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1 It would be reasonable and prudent to approve the adjusted forecasted amounts
2 provided in Table 2 above, which account for currently known project delays, and
3 would result in a disallowance of \$16,157,175 for 2024 and an increase of
4 \$5,802,315 for 2025.

5

6 **Portable Generators (Exhibit A-12, Schedule B5.4, page 13, line 28)**

7 Rebuttal Issue 10: AG Witness Coppola's recommended disallowance for Portable
8 Generators.

9 **Q40. What is AG Witness Coppola's recommendation regarding Portable**
10 **Generators?**

11 A40. He recommends full disallowance of \$4,500,000 in 2024 for Portable Generators
12 on page 32, lines 16-17 of his testimony.

13

14 **Q41. Why does AG Witness Coppola make this recommendation?**

15 A41. He makes several arguments for full disallowance on page 32 of his testimony
16 including: generators cannot be used to power furnaces and air conditioners,
17 customers will not receive a generator during the first 48 hours of storm, demand
18 for generators is likely to outstrip the supply, gasoline delivery could be
19 compromised due to nearby gas stations being without power.

20

21 **Q42. Do you agree with AG Witness Coppola's arguments for disallowance?**

22 A42. No. While the generators cannot provide heating and cooling, they do provide
23 several benefits to customers. The generators will power medical devices for
24 vulnerable customers. They will also power appliances to preserve food and allow
25 meals to be cooked. A source of frustration for many customers is having to throw

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1 out spoiled food and the costs associated to repurchase; the generators will prevent
2 this and benefit our customers. Additional benefits include powering sump pumps
3 (to prevent home flooding) and enabling customers working from home to use their
4 internet services and computer devices.

5
6 I believe there may be a misunderstanding as to the second argument. The Company
7 does not wait 48-hours before deploying generators. For example, vulnerable
8 customers with medical devices can receive a generator if they need immediate
9 assistance. I explained in discovery response U-21534 AGDE-3.93a (Exhibit A-52,
10 Schedule QQ2) that when storms occur, the Company creates a list of all customers
11 likely to be without power for at least 48 hours, and immediately contacts customers
12 on this list to offer them a generator. It appears AG Witness Coppola interpreted
13 this to mean that generators are not deployed until after the first 48 hours of storm,
14 however, this is not the case.

15
16 As to the third point, the Company has not seen any indications that generator
17 demand will exceed supply thus far. Supply and demand will be monitored, and
18 the Company will adapt accordingly to serve our customers.

19
20 As to the fourth point, the Company has several options to ensure gasoline is
21 available. This includes utilizing gasoline from the Company's field service centers
22 (stored in large underground tanks) and deploying its employees and contractors to
23 areas where gas stations have power.

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1 The Company's customers have been impacted by outages resulting from
2 increasingly frequent and severe storms. Providing portable generators to the
3 Company's vulnerable customers during storm is an effective method for
4 mitigating some of the impacts of power disruptions. I believe that the additional
5 customer benefits are reasonable and prudent.

6

7 **Base Capital Programs 2023 Underspend**

8 Rebuttal Issue 11: AG Witness Coppola's recommended removal of 2023 Base
9 Capital Programs underspend.

10 **Q43. What is AG Witness Coppola's recommendation regarding 2023 Base Capital**
11 **Programs?**

12 A43. AG Witness Coppola recommends a disallowance of \$25,202,000 for Base Capital
13 Programs on page 34, lines 14-17 of testimony.

14

15 **Q44. Why does AG Witness Coppola make this recommendation?**

16 A44. AG Witness Coppola states:

- 17 • "In discovery, the Attorney General asked the Company to report on the
18 actual amount of capital expenditures incurred in 2023 in the Electric
19 Distribution area. The information provided in response to the discovery
20 request shows that for 2023 the Company incurred actual capital
21 expenditures for Base Capital Programs of \$806,973,000. In comparison,
22 the Company forecasted \$832,175,000 for the year. The difference of
23 \$25,202,000 should be removed from rate base in this rate case." (page 34,
24 lines 11-16)

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- 1 • “The Commission has previously ruled that underspent amounts 1 included
2 in projected rate base should be removed. Therefore, I recommend that the
3 Commission continue that practice and remove the \$25,202,000 from rate
4 base in this rate case.” (page 35, lines 1-3)
5

6 **Q45. Do you agree with AG Witness Coppola’s recommendation for this**
7 **disallowance?**

8 A45. Yes, the Company agrees this disallowance is reasonable and prudent.
9

10 **Capital Emergent Replacements Storm Testimony, Processes, and Reporting**

11 Rebuttal Issue 12: Staff Witness Duell’s recommended changes to testimony.

12 **Q46. What does Staff Witness Duell recommend regarding Capital Emergent**
13 **Replacements Storm testimony?**

14 A46. Staff Witness Duell says the following on page 8, lines 9-14 of testimony, “Staff
15 had difficulty finding in testimony from the Company a description stating what it
16 is spending storm restoration expenses on and what the Company defines as storm
17 restoration expense. Staff recommends that the Company provide a brief
18 description in future cases of what the Company defines as storm restoration
19 expenses and describe what the Company plans on spending their storm restoration
20 expenses on.”
21

22 **Q47. Do you agree with Staff Witness Duell’s recommendation?**

23 A47. Yes, I agree with Staff Witness Duell’s recommendation to improve testimony
24 describing the work performed under Emergent Replacements Storm.
25

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1 Rebuttal Issue 13: MNSC Witness Denzler's incorrect statement that field personnel
2 determining whether to repair or replace assets during storm enables the Company to
3 take advantage of this new cost share structure.

4 **Q48. What does MNSC Witness Denzler say regarding field personnel deciding**
5 **whether to repair or replace during Storm?**

6 A48. MNSC Witness Denzler says on page 6, line 19 and page 7, lines 1-4, "... the
7 Company has stated there is no current standard, other than field crew judgement,
8 on when to repair versus replace field assets, and has not conducted a cost/benefit
9 analysis to support any such decisions. Particularly with the absence of any
10 objective standard, the Company may alter Storm decision making to take
11 advantage of this new cost share structure."

12

13 **Q49. Do you agree that field personnel deciding whether field assets are replaced or**
14 **repaired during storm enables the Company to advantage its cost structure?**

15 A49. No. The Company's field personnel prioritize employee and public safety and
16 speed of power restoration during storms and make the decision between repairing
17 and replacing based on these factors.

18

19 The Company's field personnel are highly trained and experienced skilled trades
20 workers. They must complete apprenticeships (4-6 years, depending on trade) and
21 must consistently demonstrate competence and sound judgment to earn their
22 professional certifications from the U.S. Department of Labor and the International
23 Brotherhood of Electrical Workers (IBEW).

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1 The Company provides field personnel supervision and training so that they are
2 equipped to make these decisions. It is reasonable to rely on the professional
3 judgment of trained experts, who work at the point of activity, and are therefore
4 best equipped to understand the condition of damaged assets in the field and
5 whether they can or cannot be repaired.

6

7 I provided an example in my direct testimony in Case No. U-21297 on page BLH-
8 32 on lines 12-17 which highlight the types of decisions that field personnel must
9 make at the point of activity, "The lineman arrives and immediately identifies a
10 broken insulator that is not securing the wire to the cross arm. As the lineman
11 ascends the pole, they then identify that the cross arm is rotted. At this time the
12 lineman would make the decision to replace both the insulator (the broken insulator
13 created the floating wire) and rotted cross arm. In this example, two pieces of
14 defective equipment was replaced."

15

16 Rebuttal Issue 14: MNSC Witness Denzler's recommendation to develop Storm
17 performance criteria.

18 **Q50. What does MNSC Witness Denzler recommend regarding Storm performance**
19 **criteria?**

20 A50. MNSC Witness Denzler recommends the following, "Order the Company to
21 develop a proposal to tie financial recovery from excess Storm spending to a
22 balanced set of relevant performance metrics to ensure an alignment of incentives,
23 using Storm performance criteria that include outage restoration, estimate accuracy,
24 resource productivity, and financial responsibility specific to Storm scenarios."
25 (page 19, lines 8-12)

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1 **Q51. Do you agree with MNSC Witness Denzler's recommendation?**

2 A51. No. I believe this recommendation to be redundant because the Company already
3 has Service Quality and Reliability Standards (SQRS) which set standards of
4 service related to the frequency and duration of storm-related outages and because
5 Case No. U-21400 is still pending which is related to Performance Based
6 Ratemaking.

7
8 **Q52. Should the Commission adopt MNSC Witness Denzler's recommendation to**
9 **require more Storm metrics reporting?**

10 A52. No. I believe these to be redundant given the SQRS and pending Performance
11 Based Ratemaking in Case No. U-21400.

12

13 **Contributions in Aid of Construction (CIAC)**

14 Rebuttal Issue 15: MNSC Witness Denzler's recommendations regarding CIAC.

15 **Q53. What does MNSC Witness Denzler recommend regarding CIAC?**

16 A53. MNSC Witness Denzler makes two recommendations regarding CIAC:

17

- 18 • "To ensure that implemented CIAC accurately reflects the current costs of
19 construction and desired contributions, I recommend the Commission order a
20 report in the next rate case proceeding detailing the impact of the CIAC
21 changes. This should include a review of the new business construction costs
22 and CIAC received, with comparison to historic and projections of future new
23 business construction costs and CIAC received." (page 11, lines 4-8)
- 24 • "Additionally, the Commission should ensure that CIAC sees regular updates
25 in the future so that it does not drift so far from actual costs again. To this end,

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1 I recommend the Commission order a regular review of CIAC costs. I
2 recommend a review cadence of at least once every two years, but certainly no
3 longer than once every five years.” (page 11, line 9-12)

4

5 **Q54. Do you agree with MNSC Witness Denzler’s recommendation for the**
6 **Company to provide a report in its next rate case that details the impact of**
7 **CIAC changes?**

8 A54. No. This information is provided in the Company’s publicly available Exhibit A-
9 12, Schedule B5.4 for each rate case.

10

11 **Q55. Do you agree with MNSC Witness Denzler’s recommendation that regular**
12 **reviews of CIAC are appropriate?**

13 A55. Yes, the Company agrees it is reasonable and prudent to have regular CIAC reviews
14 and believes a five-year cadence is appropriate.

15

16 Rebuttal Issue 16: AA Witness Stults’s recommendation regarding CIAC.

17 **Q56. What does AA Witness Stults recommend regarding CIAC?**

18 A56. AA Witness Stults states, on page 26, lines 9-19 of testimony, “I recommend the
19 CIAC be no more than it would be if the site were served by a 13.2kV system – that
20 is the Company should cover the costs for increasing the capacity in the area by 2.5
21 times before any CIAC is charged to the developer for increased capacity. A
22 developer should not have to pay the cost differential necessary to increase the
23 capacity from that of a 4.8kV system to that of a 13.2kV system. Requiring the
24 developer to cover this cost differential is unreasonable because it unfairly favors
25 projects in newer communities and discourages increasing development density in

Line
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1 older cities like Ann Arbor, Detroit, Grosse Pointe, and Highland Park that have
2 not yet been upgraded to a 13.2kV system. However, ratepayers as a whole benefit
3 from increased density by reducing the infrastructure needed to serve the customer
4 base. Thus, it is to everyone's benefit not to adopt a policy that effectively
5 encourages sprawl."

6

7 **Q57. Do you agree with AA Witness Stults that the Company's CIAC rates are**
8 **unfair for customers on 4.8kV circuits?**

9 A57. No. The Company is not aware of situations in which similarly situated customers
10 on the 4.8kV and 13.2kV systems have paid substantially different CIAC fees based
11 on the voltage of the system they are connected to. There are many factors such as
12 existing circuit and/or substation conditions, as well as customer load
13 characteristics which contribute to the potential CIAC a developer is responsible
14 for because of the impact their load addition has on the system (and thus other
15 customers). Not charging developers for their share of required system upgrades
16 and extensions will shift that burden to all customers, including the most
17 vulnerable.

18

19 **Q58. Does this conclude your rebuttal testimony?**

20 A58. Yes.

21

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.)

JEROME K. HOOPER

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JEROME K. HOOPER

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Jerome K. Hooper (he/him/his). My business address is DTE Energy
4 Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE
5 Energy Corporate Services, LLC (DTE LLC), a subsidiary of DTE Energy
6 Company (DTE Energy).

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company (DTE Electric or Company)?**

10 A2. Yes.

11

12 **Purpose of Testimony**

13 **Q3. What is the purpose of your rebuttal testimony?**

14 A3. My testimony will rebut the testimony of Staff Witness Rueckert and Attorney
15 General (AG) witness Coppola. Specifically, I will rebut:

- 16 • Staff Witness Rueckert's and AG Witness Coppola's proposed adjustments
17 to the Company's projected Active Healthcare expense,
18 • Staff Witness Rueckert's proposed adjustment to General Benefits expense,
19 and,
20 • Staff Witness Rueckert's proposed adjustment to Benefit Administration
21 Fees.

22 The absence of a discussion of other matters in my testimony should not be
23 regarded as an indication that I agree with all other aspects of the Staff's and
24 intervenor's testimony. The narrow focus of my testimony is instead a consequence
25 of a focus on priority issues in recognition of the available resources.

Line
No.

1 **Q4. Are you sponsoring any exhibits in this proceeding?**

2 A4. Yes. I am sponsoring, in whole or in part, the following exhibits:

Exhibit	Schedule	Description
A-36	AA1	Active Healthcare Expense: Updated Staff
A-36	AA2	Active Healthcare Costs: 2017-2023
A-36	AA3	General Benefits Expense: Updated Staff
A-36	AA4	Benefit Administration Fees: Updated Staff
A-36	AA5	Benefits Adjustments: Summary

9

10 **Q5. Were these exhibits prepared by you or under your direction?**

11 A5. Yes, they were.

12

13 **Active Healthcare Expense**

14 **Q6. What adjustment did Staff Witness Rueckert propose to the Company's**
15 **Active Healthcare Expense?**

16 A6. Staff Witness Rueckert develops the Company's projected Active Healthcare
17 expense based on the Company's actual 2023 Active Healthcare costs of \$80.975
18 million, escalated by the five-year average increase in the Company's Active
19 Healthcare costs for the years 2018 through 2023 of 4.83%, which results in Active
20 Healthcare costs for the projected test year of \$88.989 million. Staff Witness
21 Rueckert adjusts this cost for the portion of Active Healthcare costs expensed in
22 2022 of 60.4% to develop Active Healthcare expense for the projected test year of
23 \$53.749 million (Rueckert Revised Direct, page 8, lines 13-19).

Line
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1 **Q7. Do you agree with Staff Witness Rueckert's adjustment for Active Healthcare**
2 **expense?**

3 A7. No. Staff Witness Rueckert's approach, based on 2023 Active Healthcare costs as
4 escalated by 4.83% annually, is flawed because it relies on a single year of the
5 Company's Active Healthcare costs as a starting point, rather than my proposed
6 Constant Dollar normalized starting point, and uses an historical average of the
7 Company's actual percent changes in the Company's Active Healthcare costs,
8 rather than my use of projected medical trend rates. However, I will not repeat my
9 arguments in support of both the Constant Dollar normalization and projected
10 medical trend rates from my Direct testimony (Hooper Direct, page 14, line 13
11 through page 18, line 10). Instead, my rebuttal will offer a correction to Staff
12 Witness Rueckert's projection.

13

14 **Q8. What is your proposed correction to Staff Witness Rueckert's projected Active**
15 **Healthcare expense?**

16 A8. In 2023, the Company received a one-time credit from its Pharmacy Benefit
17 Manager (PBM) that reduced its Active Healthcare costs by \$1.134 million. Staff
18 Witness Rueckert's use of the Company's Active Healthcare costs in 2023 includes
19 that one-time credit. Because this is clearly a non-recurring item, it should be
20 excluded from the 2023 Active Healthcare costs used in determining both the
21 starting point and the historical average annual escalation rate.

22

23 **Q9. Have you computed the impact of the one-time credit on Staff Witness**
24 **Rueckert's historical analysis of the Company's Active Healthcare costs?**

Line
No.

1 A9. Yes. Exhibit A-36, Schedule AA1 reflects a recalculation of the Staff Witness
2 Rueckert's Active Healthcare cost analysis included on Exhibit S-14-4 that includes
3 an adjustment for the one-time credit. Specifically, the credit of \$1.134 million is
4 reflected in Exhibit A-36, Schedule AA1 on line 25, column (g). Exclusion of the
5 credit increases the Company's Active Healthcare costs in 2023 to \$82.109 million,
6 or a cost per employee of \$12,541, which increases the five-year average annual
7 change in Active Healthcare costs to 5.11% compared to Staff Witness Rueckert's
8 five-year average of 4.83%.

9

10 **Q10. Have you developed an update of Staff Witness Rueckert's Active Healthcare**
11 **expense projection that reflects the adjustment for the one-time credit?**

12 A10. Yes. Exhibit A-36, Schedule AA5, which is a summary of the Company's rebuttal
13 adjustments to its Benefits expense, reflects the adjusted 2023 Active Healthcare
14 expense of \$49.589 million in line 1, column (c) and applies the updated annual
15 escalation rate of 5.11% for 2024 and 2025 to develop an updated 2025 Active
16 Healthcare expense of \$54.784 million. This represents an increase to Staff
17 Witness Rueckert's projection of \$865,000.

18

19 **Q11. What did AG Witness Coppola propose regarding the Company's projected**
20 **Active Healthcare expense?**

21 A11. AG Witness Coppola projected Active Healthcare expense based on the Company's
22 actual 2023 Active Healthcare expense of \$43.241 million, as adjusted for the impact
23 of the 2022 proportion capitalized (an increase of \$5.663 million) and the one-time
24 PBM credit (an increase of \$685,000), which resulted in an adjusted 2023 Active
25 Healthcare expense of \$49.589 million. This amount was escalated by the

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1 compound average annual increase in the Company's Active Healthcare costs for
2 the years 2018 through 2022 computed by AG Witness Coppola of 3.33%. This
3 results in Active Healthcare costs for the projected test year of \$52.947 million
4 (Exhibit AG-43).

5

6 **Q12. Do you agree with AG Witness Coppola's projection of the Company's Active**
7 **Healthcare expense?**

8 A12. No. First, AG Witness Coppola rejects the Company's proposed Constant Dollar
9 normalization adjustment based on the claim that the Constant Dollar adjustment it
10 is "simply a process that increases historical costs in a way that is divorced from
11 reality" (Coppola Direct, page 112, lines 10-14). This description of the Constant
12 Dollar normalization highlights AG Witness Coppola's misunderstanding of the
13 principles underlying the Constant Dollar normalization. However, my Direct
14 testimony fully explains the basis of the Constant Dollar normalization adjustment
15 and therefore that explanation won't be repeated here (Hooper Direct, page 13, line
16 13 through page 18, line 20). Second, AG Witness Coppola's proposes to use the
17 historical increase in the Company's Active Healthcare costs from 2018 through
18 2022, yet incongruously uses the 2023 adjusted Active Healthcare expense for the
19 basis of determining the Active Healthcare expense for the projected test year.
20 While the use of historical increases in the Company's Active Healthcare costs
21 continues to be a poor predictor of the Company's future Active Healthcare costs
22 rather than projected medical trends, as described in my Direct testimony (Hooper,
23 page 22, line 43 through page 44, line 2), I won't repeat the arguments here.

24

25 **Q13. Is AG Witness Coppola's use of the annual increase in the Company's Active**
26 **Healthcare costs for the year 2018 through 2022 reasonable?**

Line
No.

1 A13. No. While I dispute the appropriateness of using the Company's historical annual
2 percent changes in its Active Healthcare costs as a basis for determining projected
3 Active Healthcare costs, there is no justification for using an historical period in
4 developing the average percent change that excludes the most recent data.

5
6 **Q14. Does AG Witness Coppola's use of the 2018 through 2022 annual percent**
7 **change in the Company's Active Healthcare costs have a material impact on**
8 **the five-year average?**

9 A14. Yes. Exhibit A-36, Schedule AA2 reflects the Company's Active Healthcare costs
10 per employee for each of the years 2017 through 2023, with the 2023 amounts
11 adjusted for the one-time PBM credit discussed above. This schedule shows that
12 the five-year average change in the Company's Active Healthcare costs is 5.11%
13 for the years 2019 through 2023 but is only 3.96% for the years 2018 through 2022,
14 or a difference of 29.0%. While AG Witness Coppola describes the 3.33%
15 historical percentage change he has developed as the "annual rate of increase"
16 (Coppola Direct, page 113, lines 7-8), it is strikingly close to the compound annual
17 growth rate of 3.35% in Active Healthcare costs between the years 2017 and 2022.
18 In contrast, the compound annual growth rate between the years 2018 and 2023 is
19 4.56%, or a difference of 36.3%. The arbitrary inclusion of the Company's Active
20 Healthcare costs for 2017 and the exclusion of 2023, as proposed by AG Witness
21 Coppola, results in a dramatic understatement of both the average of the annual
22 increase for the five years and the compound annual growth rate. There is simply
23 no logical basis for the use of the outdated historical annual average growth rate for
24 the years 2018 through 2022 when more recent data are available.

Line
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1 **Q15. Do you propose any corrections to AG Witness Coppola's projection of Active**
2 **Healthcare expense?**

3 A15. Yes. Because AG Witness Coppola appropriately included the change in the
4 proportion of costs capitalized in 2023 and impact of the one-time credit in 2023,
5 Witness Coppola proposes a 2023 starting point that matches the corrected Staff
6 Active Healthcare expense, as reflected on Exhibit A-36, Schedule AA5 of \$49.589
7 million. Therefore, the only correction that needs to be made to AG Witness Coppola's
8 projection is to reflect the updated five-year average of annual changes in Active
9 Healthcare costs of 5.11%, as developed on Exhibit A-36, Schedule AA5. This
10 results in Active Healthcare expense for the projected test year of \$54.784 million,
11 which represents an increase of \$1.837 million to AG Witness Coppola's proposal.

12

13 **Q16. What adjustment did Staff Witness Rueckert propose to the Company's**
14 **General Benefits expense?**

15 A16. Staff Witness Rueckert proposes a reduction to the Company's General Benefit
16 expense based on actual 2023 General Benefit expense escalated by a five-year
17 average of the annual percent change in General Benefit expense of negative
18 10.24%. Staff Witness Rueckert's approach results in projected General Benefits
19 expense for 2025 of \$1.051 million (Rueckert Revised Direct, page 9, lines 14
20 through 17).

21

22 **Q17. Do you agree with Staff Witness Rueckert's projection of General Benefits**
23 **expense?**

24 A17. No. Staff Witness Rueckert's projection of General Benefits expense has four
25 flaws. First, because it is based on the Company's actual General Benefits expense

Line
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1 in 2023, it ignores two one-time items that reduced the Company's expense in 2023.
2 Second, by using the 2023 actual General Benefits expense in 2023, unadjusted for
3 the two one-time expense reductions, the five-year average of the annual change in
4 General Benefits expense is understated. Third, Staff Witness Rueckert computes
5 the average annual percent change in General Benefits of negative 10.24% based
6 on the annual percent change in the Company's General Benefits expense rather
7 than the General Benefits costs. Last, because Staff Witness Rueckert uses the
8 Company's 2023 actual proportion of General Benefits costs capitalized, which
9 was distorted by the impact of O&M reductions implemented in 2023, the projected
10 General Benefits expense is understated.

11

12 **Q18. What were the two one-time cost reductions in General Benefits in 2023?**

13 A18. As a result of the financial challenges that confronted the Company in 2023 the
14 Company implemented a number of temporary cost reduction initiatives. Specific
15 to General Benefits, the Company suspended its tuition reimbursement program for
16 employees pursuing higher education and eliminated its employee service
17 anniversary award program. This resulted in a reduction in General Benefits costs
18 of \$629,000 related to tuition reimbursement and \$651,000 related to employee
19 service anniversary awards. Both of these two cost reductions in 2023 are
20 temporary and should be excluded from both the starting point in determining
21 projected General Benefits expense and in the determination of the five-year
22 historical average of annual percent changes used to escalate General Benefits
23 expense through the end of the projected test year.

Line
No.

1 **Q19. Why is it improper to use the five-year average of the percent change in**
2 **General Benefits expense rather than the five-year average of the General**
3 **Benefits costs?**

4 A19. The use of the five-year average of the annual percent change in the Company's
5 General Benefits expense is improper as a basis for determining future escalations
6 because the historical average is distorted by changes in the proportion of General
7 Benefits costs capitalized. For example, in 2018 the proportion General Benefits
8 costs allocated to expense was 68.0%, whereas in 2023 the proportion of General
9 Benefits costs allocated to expense declined to 58.7%. This decline in the
10 proportion of General Benefits costs allocated to expense distorts the average
11 annual change in General Benefits expense because it reflects both the change in
12 costs and the change in the proportion of General Benefits costs charged to expense.
13 A more meaningful measure of the average annual percent change is based on the
14 change in General Benefits costs, undistorted by changes in proportion of costs
15 capitalized.

16
17 **Q20. What proportion of General Benefits costs allocated to expense should be used**
18 **in determining the normalized 2023 General Benefits expense?**

19 A20. The actual 2023 proportion of General Benefits costs allocated to expense was
20 58.7%. However, the proportion of General Benefits costs allocated to expense in
21 2022 was 64.6%. Because the 2023 proportion of General Benefits costs charged
22 to expense was distorted by the temporary O&M reductions implemented by the
23 Company, as described by Company Witness Uzenski, the proportion of General
24 Benefits costs allocated to expense in 2022 is more representative of the proportion
25 that will be allocated to expense in the projected test year. Accordingly, the 2023

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1 General Benefits expense should be adjusted for the change in the proportion
2 allocated to expense.

3

4 **Q21. Have you computed the impact of the one-time reductions in General Benefits**
5 **costs in 2023, the annual percent change in General Benefits costs and the**
6 **change in the proportion General Benefits costs allocated to expense in 2023?**

7 A21. Yes. Exhibit A-36, Schedule AA3 reflects a restatement of Staff Witness
8 Rueckert's Exhibit S-14-4 that includes the impact of the two one-time adjustments
9 and the use of the proportion of General Benefits costs allocated to expense in 2022.
10 The impact of these adjustments is to increase the total General Benefits costs in
11 2023 by \$1.280 million, which increases the five-year average of the historical
12 average annual change in General Benefits costs to negative 0.51% compared to
13 Staff Witness Rueckert's five-year average of the change in General Benefits
14 expense of negative 10.24%. The adjustment for the two one-time cost reductions
15 increases the Company's 2023 General Benefits expense by \$826,000, which
16 results in an adjusted 2023 General Benefits expense of \$2.262 million.

17

18 **Q22. How do these adjustments to the Company's 2023 General Benefits expense**
19 **and the five-year average of the annual percent change in General Benefits**
20 **costs impact the Staff Witness Rueckert's projected General Benefits expense?**

21 A22. The impact of these corrections to Staff Witness Rueckert's projected General
22 Benefits expense is reflected on Exhibit A-36, Schedule AA5, which starts with the
23 adjusted General Benefits expense of \$2.262 million and escalates this amount by
24 the five-year average of the annual change in the Company's General Benefits costs
25 of a negative 0.51% for both 2024 and 2025 to develop an updated General Benefits

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1 expense for the projected test year of \$2.239 million. This projection is \$1.188
2 million higher than the General Benefits expense projected by Staff Witness
3 Rueckert.

4
5 **Q23. What adjustment did Staff Witness Rueckert propose to the Company Benefit**
6 **Administration Fees?**

7 A23. Staff Witness Rueckert proposes a reduction in the Company's projected Benefit
8 Administration Fees based on the 2023 actual Benefits Administration Fees
9 expense in 2023 escalated by a five-year average of annual percent change in the
10 Benefit Administration fees for the years 2019 through 2023. Staff Witness
11 Rueckert's projects Benefit Administration Fees of \$4.708 million, which
12 represents a reduction in the Company's projected Benefit Administration Fees of
13 \$2.855 million (Rueckert Revised Direct, page 10, lines 19 through 22).

14
15 **Q24. Do you agree with Staff Witness Rueckert's proposal?**

16 A24. No. Staff Witness Rueckert's projection of Benefit Administration Fees has two
17 flaws. First, Staff Witness Rueckert's five-year average of the annual change in
18 Benefit Administration Fees is based on the Company's Benefits Administration
19 Fees expense, after reduction for the proportion of the costs capitalized, which like
20 General Benefits, is distorted by changes in the proportion of Benefit
21 Administration Fees capitalized. Second, Staff Witness Rueckert's projected
22 Benefit Administration Fees is based on the proportion of Benefit Administration
23 Fees allocated to expense in 2023, which was distorted by one-time O&M
24 reductions implemented by the Company in 2023, as explained by Company
25 Witness Uzenski.

Line
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1 **Q25. Have you computed a revised Benefit Administration Fees expense for the**
2 **projected test year that reflects the impact of using a five-year average of**
3 **annual percent change in the Company's Benefit Administration Fees costs**
4 **and the change in the proportion Benefit Administration Fees costs allocated**
5 **to expense in 2023?**

6 A25. Yes. Exhibit A-36, Schedule AA4 reflects a restatement of Benefit Administration
7 Fees on Staff Witness Rueckert's Exhibit S-14-4, which develops a five-year
8 average of the annual percent change in the Benefit Administration Fees costs,
9 unadjusted for the proportion of costs capitalized, of negative 3.66%, compared to
10 Staff Witness Rueckert's five-year average of the changes in the Benefit
11 Administration Fees of negative 5.57%. This schedule also adjusts the Benefit
12 Administration Fees expense in 2023 of 54.8% to the 2022 proportion Benefit
13 Administration Fees allocated to expense of 60.1%.

14

15 **Q26. How do these updates of Benefit Administration Fees impact Staff Witness**
16 **Rueckert's projections of Benefits Administration Fees?**

17 A26. Exhibit A-36, Schedule AA5 reflects the derivation of an updated projection
18 Benefit Administration Fees based on the adjusted 2023 Benefit Administration
19 Fees expense adjusted to reflect the 2022 proportion of Benefit Administration Fees
20 capitalized of \$5.788 million and escalated in 2024 and 2025 by the five-year
21 average of the annual change in Benefit Administration Fees costs of negative
22 3.66%. The combination of the adjusted 2023 Benefit Administration Fees expense
23 and corrected annual escalations results in projected Benefit Administration Fees
24 for 2025 of \$5.372 million, which is an increase of \$664,000 to Staff Witness
25 Rueckert's projection.

Line
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1 **Q27. Is the use of the historical change in the costs rather than expense and the use**
2 **of the 2022 proportion of costs allocated to expense for General Benefits and**
3 **Benefits Administration Fees consistent with Staff Witness Rueckert's**
4 **proposed Active Healthcare expense?**

5 A27. No. Staff Witness Rueckert properly based the five-year average of the annual
6 percent change used in escalating 2023 Active Healthcare expense based on the
7 annual percent change in Active Healthcare costs rather than the annual percent
8 change in Active Healthcare expense. Similarly, Staff Witness Rueckert properly
9 used the 2022 proportion of Active Healthcare costs allocated to expense in the
10 development of the projected Active Healthcare expense. Accordingly, the
11 adjustments I'm proposing for General Benefits expense and Benefit
12 Administration Fees expense are consistent with Staff Witness Rueckert's
13 development of projected Active Healthcare expense.

14

15 **Q28. Does this conclude your rebuttal testimony?**

16 A28. Yes, it does.

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.)

ALLEN J. KRYSZYNSKI

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF ALLEN J. KRYSCYNSKI

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Allen J. Kryscynski (he/him/his), and my business address is One
4 Energy Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric
5 Company

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.
10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of this testimony is to rebut certain positions of:

- 14 • Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
- 15 Witness Tayler Becker
- 16 • Attorney General (AG), Michigan Environmental Council (MEC), Natural
- 17 Resource Defense Council (NRDC), collectively AG-MN Witness Paul
- 18 Alvarez
- 19 • AG-MN Witness Dennis Stephens
- 20 • City of Ann Arbor (AA) Witness Melissa Stults
- 21 • AA Witness Skye Stewart
- 22 • Michigan Municipal Association for Utility Issues (MAUI) Witness
- 23 Richard Bunch
- 24 • Soulardarity and We Want Green, Too (collectively DAAO) Witness
- 25 Elizabeth Jacob

Line
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- 1 • DAAO Witness Yunus Kinkhabwala, PhD
- 2 • DAAO Witness Jackson Koeppel
- 3 • The Ecology Center, The Environmental Law & Policy Center, Union of
- 4 Concerned Scientists, and Vote Solar (CEO) Witness Curt Volkmann
- 5 • CEO Witness Boratha Tan
- 6 • CEO Witness William Kenworthy
- 7

8 **Q4. Are you sponsoring any exhibits in this proceeding?**

9 A4. Yes. I am sponsoring the following exhibits:

10	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
11	A-43	HH1	MNSCDE-15.23a – Depreciation
12	A-43	HH2	Assessing Changes in the Reliability of the U.S.
13			Electric Power System - LBNL
14	A-43	HH3	Recent trends in power system reliability and
15			implications for evaluating future investments in
16			resiliency
17	A-43	HH4	WP AJK U-21534 GPM
18	A-43	HH5	WP AJK U-21534 Reliability Model
19	A-43	HH6	MNSCDE-12.8b - Reliability Program
20			Analysis

21

22 **Q5. How is your testimony organized?**

23 A5. There are several specific points I will rebut in my testimony; subjects are listed

24 below. A detailed discussion follows to correct inaccuracies and explain why

25 certain recommendations should not be accepted by the Commission.

Line
No.

Rebuttal Content

1		
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32		

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1 **Rebuttal Issue 1: System Wide All-Weather Reliability**

2

3 **Q6. What concerns about reliability are expressed by intervenors?**

4 A6. AG-MN Witness Stephens at page 9, lines 8-10, AG-MN Witness Alvarez at page
5 17 line 12, and AA Witness Stults at page 5 line 12 all suggest that all-weather
6 system-wide reliability is not showing an improvement trend, despite recent
7 increases to investment.

8

9 **Q7. Can you please explain why a review of system wide reliability metrics may**
10 **not reflect the investments that are improving sections of the grid?**

11 A7. Yes. When looking at the macro-level, system wide all-weather SAIDI and SAIFI
12 inherently include the volatility of the weather conditions that greatly influence
13 these two reliability measures. When examining these measures narrowly, without
14 taking a longer-term view, reliability is not on a trend that is improving year-over-
15 year. The variability in performance is due in large part to the factors I noted in my
16 revised direct testimony, page 22, Q24, where I discussed three issues summarized
17 here:

18 1) High winds have been increasing over time, causing additional
19 equipment stress and outages.

20 2) Even with the current level of investment, distribution system
21 equipment continues to get older. For example, DTE Electric's wood
22 poles have an average age of approximately 48 years. Furthermore, 32%
23 of poles are over 60 years old, and 10% over 80 years old. Lastly, these
24 older poles are not designed nor built to the current, more resilient
25 construction standards.

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1 3) The Company is early on its journey to stabilize and rebuild the grid.
2 Our strategic capital investment in 2022 was \$715 million, in 2019 it
3 was \$313 million. DTE Electric's distribution system, because of its size
4 and complexity, requires sustained higher levels of investment to affect
5 a change in reliability metrics at an overall system level.

6

7 **Q8. In addition to system-wide all-weather reliability, are there other metrics or**
8 **analysis that should be used to understand the reliability improvements of**
9 **investments, including tree trimming?**

10 A8. Yes. Many of our customers are in fact seeing reliability improvement, in the areas
11 where we have invested. First, as discussed in Q23 of my revised direct testimony,
12 we have seen reliability improvements in the areas that we have tree trimmed and
13 are maintaining tree clearance, and in areas where we have invested in capital
14 infrastructure upgrades. Over multiple rate cases, including this one, the
15 Company's distribution Witnesses have provided rigorous, compelling data
16 analysis to show that these investments are delivering benefits.

17

18 As an example of these benefits, communities that have had grid investments are
19 seeing greater resilience to storms. During the first week of June 2024, the
20 community of Livonia experienced an EF1 (Enhanced Fujita Scale) tornado with
21 wind speeds up to 95mph. The area which took the main impact from the tornado
22 recently had over 200 poles replaced as part of the Pole and Pole Top Maintenance
23 and Modernization Program (PTMM) program. These upgrades resulted in minimal
24 damage, including only 3 broken poles, and resulted in a faster restoration effort -
25 99% of customers were restored within 27 hours. On the other hand, an adjacent

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1 area of the system where PTMM investments have not yet been implemented was
2 also in the path of the storm. In this area the Company experienced 20 broken poles,
3 resulting in over 5,000 customers who had to endure service outages lasting more
4 than 48 hours due to the volume of events and severity damage.

5
6 Second, in the 2023 DGP the Company has provided a roadmap of investments and
7 paired that roadmap with a sophisticated reliability model, also provided in this case
8 to support the Company's proposed investments. The reliability model supports the
9 Company's assertion that if the proposed capital investments are made, there will
10 be significant improvements in the Company's non-MED and all-weather
11 reliability metrics.

12

13 **Rebuttal Issue 2: Required Capital Investment**

14

15 **Q9. Please summarize AG-MN Witness Stephens' context for his testimony related**
16 **to distribution investments.**

17 A9. Witness Stephens (pages 6 line 2 through page 7 line 5) begins his testimony by
18 differentiating what he terms "discretionary" spending from non-discretionary
19 spending. His definition of discretionary is "If the capital is not spent, can
20 customers still have safe and reliable service?" He then proposes that all
21 "discretionary" spending be subject to what he terms "risk-informed benefit -cost
22 analysis".

23

24 **Q10. Do you agree with AG-MN Witness Stephens' definition of discretionary**
25 **investments?**

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1 A10. No. Merriam Webster¹ provides synonyms of the word “discretionary” that include
2 optional, unnecessary, and unneeded. With his definition, Witness Stephens
3 oversimplifies the planning and scope of investments needed to have a safe,
4 reliable, and accessible grid. He doesn’t provide a timeframe for “safe and reliable
5 service”, and his definition could be interpreted as only considering the current,
6 immediate grid condition, instead of planning ahead for future reliability or safety
7 risks. This would be similar to determining whether or not to replace aged, worn
8 tires on a car. The tire replacement using his definition is discretionary, right up
9 until the moment when the tire skids on wet pavement, a safety concern, or blows
10 out while driving on a highway, a safety and reliability concern. Witness Stephens’
11 also fails to account for the fact that in-service failures, be it car tires or electrical
12 equipment, are typically far more costly than carefully planned investment.

13

14 **Q11. Do other Witnesses adopt AG-MN Witness Stephens’ use of what they view as**
15 **discretionary vs non-discretionary investments?**

16 A11. Yes. AG-MN Witness Alvarez on page 14 lines 1-5 of his direct testimony notes
17 that “... almost all of the projects within these [strategic capital] programs are
18 discretionary as to timing and extent. This means that none are required to address
19 equipment failures or equipment damage; or connect new customers; or
20 accommodate near-term load increases”

21

22 **Q12. Do you agree that the strategic capital programs AG-MN Witness Alvarez**
23 **claims are discretionary programs do not address “equipment failures and**
24 **equipment damage”?**

¹ “Discretionary.” *Merriam-Webster.com Thesaurus*, Merriam-Webster, <https://www.merriam-webster.com/thesaurus/discretionary>. Accessed 14 Aug. 2024.

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1 A12. No, Witness Alvarez' statement is incorrect. For example, as discussed by Witness
2 Elliott-Andahazy in her revised direct testimony, the purpose of the PTMM
3 program is targeted at replacing failed or damaged equipment. This includes broken
4 cross arms, poles that have failed strength tests, cracked/broken insulators,
5 crack/broken fuse cutouts, and blown fuses. Subtransmission projects, and
6 conversion projects discussed by Witness Deol in his direct testimony replace this
7 same type of equipment in the course of construction as well, with additional work
8 included. Additionally, programs including PTMM, Breaker Replacement, System
9 Cable, and URD target equipment replacements that have either failed in the past
10 or have known high failure rates and are expected to fail again in the near future.
11 Please reference Witness Elliott-Andahazy's revised direct testimony, Figure 7, for
12 visual examples of broken equipment that is typically replaced when identified as
13 part of the PTMM inspection.

14

15 **Q13. As an alternative to AG-MN Witness Stephen's "discretionary" and "non-**
16 **discretionary" definitions, is there a broader industry-recognized standard to**
17 **evaluate segregations of utility investments?**

18 A13. Yes. The Department of Energy (DOE) in its DSPx model segregates utility grid
19 investments into "core components" and "applications." Core components
20 comprise the essential technologies that provide a foundation for a modern
21 distribution system, while applications represent the various additional
22 technologies that can layer on top of core components to add additional
23 functionality to the grid.
24 The DOE in its DSPx model states that "core distribution cyber-physical and
25 operational platform components include:

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- 1 • Physical infrastructure (e.g. wires, transformers, switches, etc.)
- 2 • Advanced protection and controls
- 3 • Sensing and situational awareness
- 4 • Operational communications
- 5 • Planning tools and models (e.g., DER & load forecasting, power flow analysis,
- 6 etc.)

7 These components comprise the essential technologies that provide a foundation
 8 for a modern distribution grid. DOE's Modern Grid Initiative², EPRI's research³
 9 and others over the past 15 years have consistently identified these five categories
 10 as core or foundational components of the grid.”⁴

11

12 **Q14. Is it your understanding that the criterion that the Commission uses to**
 13 **determine if an investment proposed by a utility should be included in rate**
 14 **base for the purpose of cost recovery is whether that investment is**
 15 **“discretionary” or “non-discretionary”?**

16 A14. No, it is my understanding that the MPSC approves investments proposed by a
 17 utility for cost recovery in rates if the Commission determines that the investments
 18 are reasonable and prudent as well as other considerations.

19

20 **Q15. What other concern does AG-MN Witness Alvarez have regarding the need**
 21 **for equipment replacements to improve grid reliability?**

² U.S. Department of Energy. Grid Modernization Initiative, 2017

³ Electric Power Research Institute. Needed: A Grid Operating System to Facilitate Grid Transformation. July 2011. Available online:

https://www.smartgrid.gov/files/documents/Needed_Grid_Operating_System_to_Facilitate_Grid_Transformation_201108.pdf, accessed August 6, 2024

⁴ Next-Generation Distribution System Platform Initiative (DSPx) Modern Distribution Grid Volume I – Strategy and Implementation Planning, page 25, available at <https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf>, accessed August 6, 2024

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1 A15. On page 17, lines 10-12, he quotes the 2023 Distribution Grid Plan (DGP):

2 “much of the current infrastructure is at or beyond *expected*
3 *useful life* and susceptible to failure, particularly when
4 exposed to extreme weather” (emphasis added)

5 then goes on to say on page 17 line 12 through page 18 line 2:

6 “This statement contains several misleading statements.
7 First, “*expected useful life*” is a reference to depreciation
8 periods, which are based on the average age of assets in
9 service” (emphasis added),

10 and then concludes on page 18, lines 8-10:

11 “To decide that equipment should be replaced simply
12 because it is *fully depreciated*, when decades of useful life
13 might be remaining, serves shareholders at customers’
14 expense.” (Emphasis added).

15 **Q16. Is AG-MN Witness Alvarez correct in his assertion that equipment is replaced**
16 **“simply because it is fully depreciated”?**

17 A16. No, for two reasons. Witness Alvarez misunderstands the criteria the Company uses
18 when assessing the need to replace equipment. First, he is incorrect in his
19 assumption that the Company’s use of the term “expected useful life” is a reference
20 to depreciation periods. In discovery response MNSC 15.23a, Exhibit A-43
21 Schedule HH1 - MNSCDE-15.23a – Depreciation, when asked to confirm that the
22 Company uses the terms “useful life” and “depreciation period” interchangeably,
23 Company Witness Elliott Andahazy responded “Not confirmed.” She then clarified
24 that the Company uses depreciation rates for the purpose of calculating depreciation
25 expense.

26

27 Secondly, in my revised direct testimony, on page 17, lines 1 through 16, I describe
28 that the Company’s subject matter experts use many factors when determining

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1 equipment expected life expectancy, which is used in estimating investment needed
2 for equipment replacements. I further describe that equipment age, but not
3 depreciation status, is just one of the factors considered to assess asset health and
4 the need for replacement.

5

6 **Q17. Does equipment depreciation status factor into the Company's distribution**
7 **equipment replacement decisions?**

8 A17. No.

9

10 **Rebuttal Issue 3: Equipment Outages**

11

12 **Q18. Witness AG-MN Stephens, in addressing what he believes to be the cause of**
13 **outages, makes the statement that "storm response and vegetation**
14 **management – not equipment condition – have driven the Company's**
15 **historically poor (relative to peers) reliability performance".⁵ Similarly**
16 **Witness Alvarez says "Given that vegetation contact is the root cause of at least**
17 **50% of the interruption minutes customers experience, spending should be**
18 **focused on root causes."**⁶ **Do you agree with Witness Alvarez and AG-MN**
19 **Witness Stephens' characterization of the key drivers of reliability?**

20 A18. I agree that vegetation is a significant cause of outages, which is why the Company
21 began the Tree Trim Surge program in 2019. However, I believe that focusing
22 solely on vegetation would not by itself address the complex set of factors that
23 influence distribution reliability.

24

⁵ Stephens DT page 7, lines 19-20

⁶ Alvarez DT, page 19, lines 12-14

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1 **Q19. Can you provide more detail on what you call the complex set of factors that**
2 **influence distribution reliability?**

3 A19. Yes. The full analysis of grid reliability needs to address both the initiating event
4 that caused the outage (i.e., trees/wind) and the underlying equipment that was not
5 resilient to trees/wind. As an example, on a circuit which is on-cycle for tree
6 trimming could have an out of right of way tree that falls into the lines. When this
7 happens, whether an outage occurs or not, the size of the outage, and the extent of
8 damage is determined in part by the equipment that the tree encounters. If the
9 equipment is aged or built to a previous less-robust engineering and construction
10 standard, the tree will be more likely to break the equipment. However, if the circuit
11 has been rebuilt to the current stronger standard, with larger poles, fiberglass cross
12 arms, and steel reinforced wire, the equipment may not fail or the damage will be
13 minimized. Additionally, automation investments will provide even more
14 improvements to reliability. Using a similar example, if high winds cause a large
15 branch to create an outage and an automated recloser loop scheme is installed on
16 that circuit, not only will the outage be reduced in size (number of customers
17 affected) but the Company will have information on specifically where the outage
18 occurred, which will allow the Company to dispatch crews directly to the location
19 without the need to patrol the circuit. A more detailed description of automation
20 benefits can be found in Witness Hartwick's revised direct testimony on pages 11
21 through 12.

22

23 **Q20. Do you agree with AG-MN Witness Stephens' characterization of the**
24 **Company's "storm response" as a key driver impacting reliability**
25 **performance?**

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1 A20. No. The Company has storm processes in place that allow the Company to mobilize
2 and respond quickly to storms, and the Company continues to evaluate and improve
3 its storm response processes. Witness Stephens fails to account for the real issue
4 impacting “storm response” which has been, and is still today, the volume of events
5 that occur during a narrow window of time during large weather events. During
6 these storms, the Company typically has significantly more outage events than line
7 crews to assign to mitigate the events due to the amount and complexity of damage
8 that occurs. Even with the additional support of foreign crews, restoration can
9 become a supply vs. demand problem. And while the Company has made
10 improvements to increase the supply of lineman, the Company must also reduce the
11 demand for linemen, meaning the need to reduce the number of outage events by
12 hardening the grid in order to continue to mitigate and fully solve this problem. In
13 summary, the storm response challenges are primarily driven by event volume, in
14 part, by equipment that is no longer capable of standing up to increasingly harsh
15 weather conditions.

16

17 **Q21. Based on his interpretation of DTE Electric’s reliability data, what are AG-**
18 **MN Witness Alvarez’s conclusions and recommendations?**

19 A21. Witness Alvarez’s conclusion is equipment related failures are not a significant root
20 cause of outages, and that capital programs such as automation, which admittedly
21 improve reliability by reducing the impact of outages, are not an effective approach
22 to improve reliability (page 19, lines 8-15). He also recommends that the
23 Commission:

24 “Require DTE to slow the rate of capital spending and assess
25 the benefits of its vegetation management program relative
26 to strategic capital spending aimed at improving reliability.”
27 (Alvarez, page 8, lines 9-11)

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1 **Q22. Does AG-MN Witness Alvarez reference any studies to support his conclusion**
2 **that capital investment should be slowed?**

3 A22. Yes. On page 16, lines 4-6, Witness Alvarez says:

4 “Research completed by Lawrence Berkeley National
5 Laboratory on behalf of the U.S. Department of Energy
6 found no correlation between investor-owned utility
7 distribution capital spending increases and reliability
8 improvement the following year.”

9 The study cited in his testimony at the bottom of page 16 is “Assessing Changes in
10 the Reliability of the U.S. Electric Power System. Lawrence Berkeley National
11 Laboratory report LBNL-188741 (August 2015), pp. 37-38.”

12

13 **Q23. Is AG-MN Witness Alvarez’s correctly interpreting LBNL’s research that**
14 **there is no correlation between capital and reliability improvements accurate?**

15 A23. No. Witness Alvarez’s conclusion there is no correlation between capital
16 investment and reliability improvements is incorrect. In fact, it’s impossible given
17 the inputs into the study. The LNBL study, included as Exhibit A-43, Schedule
18 HH2⁷ - Assessing Changes in the Reliability of the U.S. Electric Power System -
19 LBNL, talks about spending in terms of "maintenance" (O&M). The O&M spend
20 that was analyzed was not only distribution O&M but bundled to include
21 transmission O&M dollars. Capital investment was not analyzed in this study. A
22 subsequent journal article published by the authors, Exhibit A-43, Schedule HH3 –
23 “Recent trends in power system reliability and implications for evaluating future
24 investments in resiliency”, is even more precise in defining spending as "T&D
25 O&M expenditures".

26

⁷ Exhibit A-43, Schedule HH2 page 17

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1 **Q24. Did the LBNL study conclude there was no correlation between O&M**
2 **spending and reliability the following year?**

3 A24. No, in fact this journal article indicates that 10 of the 12 models evaluated had a
4 negative sign for the expenditures variable as summarized in Tables A.4 and A.5 in
5 Schedule HH3, although many were not statistically significant. The negative sign
6 means that previous year O&M spending is correlated with an improvement in
7 reliability (SAIDI+SAIFI) the following year.

8

9 **Q25. What concerns does AG-MN Witness Stephens have about the impact of**
10 **equipment failures on reliability?**

11 A25. Witness Stephens performed an analysis on a small set of outage events and claimed
12 that the percentage of interruptions caused by equipment is small – less than 12%.
13 (Page 8, lines 5-10)

14

15 **Q26. Does the Company have concerns with AG-MN Witness Stephen's analysis?**

16 A26. Yes, the Company has two main concerns. The first is that the Company was unable
17 to verify Witness Stephens' analysis. He claims he examined 100 service
18 interruptions with the cause of 'equipment failure' (page 8, line 7), however the file
19 provided only included 77 events with the cause of 'equipment failure' and only 68
20 indicated any analysis had been done. The second, and more important concern
21 regarding Witness Stephens' analysis is that he relied on outage crew field notes
22 provided by the Company to determine if equipment caused the outage. Field notes
23 are not intended to document the cause of outages, rather they are used in the
24 moment as a means of communication between various field resources and the
25 systems operations center to co-ordinate and facilitate restoration. The primary

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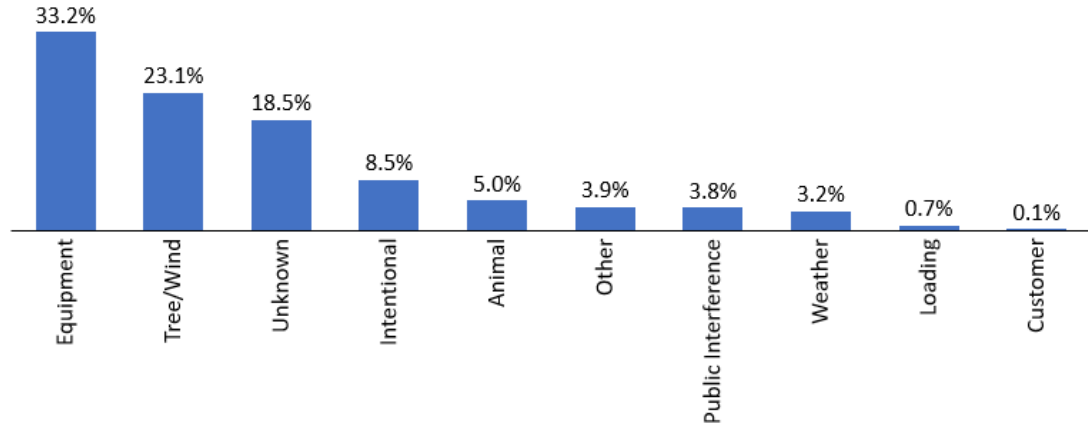
1 indicator of the cause of the outages is the cause code field in the outage
2 management system.

3

4 **Q27. What analysis has the Company performed to estimate the cause of outages?**

5 A27. The Company has calculated the percentages of customer interruptions, by cause
6 code, under non-MED conditions over the past five years. The results, by cause
7 code, are shown in Figure 1 below. The cause code 'Equipment Failure' is the
8 largest contribution to customer interruptions, followed by tree/wind related events.
9 The conclusion from this analysis is that equipment is indeed a leading cause of
10 outages, and the tree trimming program, while important to address tree related
11 outages, is not sufficient to address a significant portion of outages.

12 **Figure 1 Customer Interruptions by cause code (2019-2023, Non-MEDs)**



13

14 **Q28. Do you agree with Witness Alvarez's recommendation to slow capital**
15 **spending⁸ to assess benefits of its tree trim program relative to its capital**
16 **program?**

17 A28. No. There are several reasons why I disagree:

⁸ Alvarez DT, p. 8, lines 9-11

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- 1 1) Customers are clear that they want to see significant reliability
- 2 improvements even in the face of storms.
- 3 2) With 90%⁹ of the system on cycle for Tree Trimming by the end of
- 4 2024, the Company's reliability model indicates that the two largest
- 5 opportunities to improve reliability are Circuit Automation¹⁰ and
- 6 replacing degraded equipment (PTMM, Hardening, Conversion), which
- 7 will account for almost 80% of the projected all-weather SAIDI
- 8 improvements by 2029. Delaying this work will hamper the Company's
- 9 ability to improve customer reliability in the near-term.
- 10 3) The majority of our customer interruptions are not tree related.¹¹
- 11 4) The benefits of the Tree Trim program are well known, and analysis has
- 12 been presented in this rate case, past rate cases, and annual tree trim
- 13 reports submitted to the Commission for years.
- 14 5) While the Company's Tree Trim program has proved highly effective,
- 15 the Company's recent reliability performance shows that more capital
- 16 infrastructure investment is needed.

⁹ See Witness Steudle testimony, page 15, line 14

¹⁰ As Witness Alvarez notes on page 19, lines 10-12, DTE Electric's Distribution Automation program is "designed to mitigate the impact of service interruptions."¹¹ Data in the 2023 DGP shows that 69% of all-weather SAIFI and 50% of all-weather SAIDI is from causes other than trees. See Exhibits 4.2.2.1 and 4.2.2.2 within the 2032 DGP, (Exhibit A-23, Schedule M8)¹² Order in U-21297 filed on 12/1/2023 available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000At0VBAAZ>.

¹¹ Data in the 2023 DGP shows that 69% of all-weather SAIFI and 50% of all-weather SAIDI is from causes other than trees. See Exhibits 4.2.2.1 and 4.2.2.2 within the 2032 DGP, (Exhibit A-23, Schedule M8)¹² Order in U-21297 filed on 12/1/2023 available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000At0VBAAZ>.

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1 **Rebuttal Issue 4: Capital Investment Governance**

2

3 **Q29. What concerns does AG-MN Witness Alvarez have related to the Company's**
4 **strategic capital investment governance?**

5 A29. AG-MN Witness Alvarez first divides distribution capital investments into defined
6 capital projects and strategic capital programs. He finds no deficiencies in defined
7 capital projects, and in fact provides an appropriate summary of the capital project
8 process. (page 27, lines 5-7) For strategic capital programs however, he notes
9 perceived deficiencies in the Company's planning and cost tracking, which is how
10 he defines governance (page 27, lines 7-9).

11

12 **Q30. What does AG-MN Witness Alvarez believe are deficiencies in the planning**
13 **and cost tracking of the Company's strategic capital investment programs?**

14 A30. On page 27, lines 11-12, Witness Alvarez specifically calls out the PTMM,
15 Hardening, Distribution Automation (DA) programs and notes that these programs
16 "appear to be managed only at the program level as opposed to project level." He
17 appears to arrive at this conclusion because he was unable to find annual program
18 goals for units such as circuit miles or DA devices, what he calls "established
19 expectations". (page 27, line 15 – page 28, line 2).

20

21 **Q31. Has the Company provided units for strategic capital programs in**
22 **documentation in the instant case?**

23 A31. Yes. I'll provide two examples, for programs he referenced in his testimony.
24 First, for DA, Witness Hartwick on page 19 of her revised direct testimony, Q33,
25 identified the DA plan for 2024, which included infrastructure recovery mechanism

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1 (IRM) related work for 63 circuits and a total of 189 recloser devices, and an
2 additional 32 circuits with 96 recloser devices for the 4.8kV system. She further
3 identified the 2024 engineering and design work for recloser devices that would be
4 installed on circuits in 2025, 240 reclosers on approximately 80 circuits.

5

6 As a second example, for the PTMM program, Witness Elliott Andahazy on page
7 53, table 12 of her direct testimony, provides the program goals in 2024 and 2025.
8 For 2024, the program goals include 750 circuit miles, 1,700 pole replacements,
9 and 8,655 pole top replacements, for a program cost of \$63,450,000. In addition to
10 direct testimony, the Company Distribution Witnesses provided copious details
11 related to program and project units in discovery.

12

13 **Q32. Does AG-MN Witness Alvarez have any other concerns related to strategic**
14 **capital program governance?**

15 A32. Yes. Stemming from his concern about planning and cost tracking related to
16 established expectations for units, he believes that this can lead to an inability to
17 track program improvements (page 28, line 1), which he also reiterated when he
18 said “program benefit projections can be over-estimated” (page 28, line 7).

19

20 **Q33. Do you agree with AG-MN Witness Alvarez’s conclusions related to tracking**
21 **and the potential over-estimating of program benefits?**

22 A33. No. As I discussed above, the Company can and does have annual goals for
23 program units achieved, which is the basis of his concern. Additionally, Company
24 Witnesses Hartwick and Elliott Andahazy cover the benefits of their programs, and
25 the Company’s reliability model where the program benefits are modeled.

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1 **Rebuttal Issue 5: Benefit Cost Analysis**

2

3 **Q34. What feedback was provided by the Commission and other stakeholders**
4 **regarding the previous version of the Global Prioritization Model (GPM) and**
5 **Benefit Cost Analysis (BCA), and use of the DGP in supporting rate case**
6 **investments in their order in Case No. U-21297 (the Company's prior rate**
7 **case)?**

8 A34. The Commission wrote the following regarding the GPM, the DGP, and how the
9 Company prioritizes its investments on p71¹²:

- 10 1) "The Commission notes that DTE Electric presented the GPM and
11 the DGP as the sole sources of support for many capital expenditure
12 programs in the distribution category"
- 13 2) "The Commission requires greater transparency into the basis for
14 the GPM"
- 15 3) "To the extent that either the GPM or the DGP offers a facsimile of
16 a BCA, costs are not always addressed and benefits are not always
17 quantified"

18

19 **Q35. Did the Company provide additional sources of support for distribution**
20 **investments in this case?**

21 A35. Yes, there are at least three additional sources of support for distribution
22 investments in the instant case. The first is the level of detail on both project
23 purpose, scope and benefits in the capital summaries (Exhibit A-23, Schedules M5,
24 M6, and M7). Secondly, the Company developed a new BCA methodology for two

¹² Order in U-21297 filed on 12/1/2023 available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000At0VBAAZ>.

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1 investment areas, PTMM and Undergrounding, and provided these BCA
2 spreadsheets and calculations as part of the case. Finally, the Company developed
3 a more comprehensive, circuit-level, reliability model to help tie potential
4 investments in six key investment areas (Tree Trimming, 4.8kV Hardening,
5 PTMM, Customer Excellence, Distribution Automation, and 4.8kV Conversion) to
6 future reliability improvements.

7

8 **Q36. How did the Company provide more transparency into the basis for GPM?**

9 A36. The Company submitted a working version of the GPM as a workpaper in this case,
10 which included all the assumptions and underlying data on project and program
11 costs and benefits. The Company also submitted the Reliability Model as a
12 workpaper which includes a bottoms-up, circuit level projection of reliability
13 impacts for the six programs mentioned above. Additionally, supporting
14 documentation and analysis for both models was provided throughout the discovery
15 process. Those workpapers are included as Exhibits A-43, Schedule HH4 - WP
16 AJK U-21534 GPM and A-43 Schedule, HH5 - WP AJK U-21534 Reliability
17 Model.

18

19 **Q37. Does the Company plan to continue to enhance and improve the methods used**
20 **to evaluate projects and programs, including quantified benefits?**

21 A37. Yes, the Company intends to further enhance its already strong investment analysis
22 supplemented by the latest BCA presented in this case. It is worth noting that not
23 every grid/reliability investment can be effectively translated into a monetized
24 valuation as the sole basis for the investment decision making process. The
25 Company is committed to explore further improvements in support of the less

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1 tangible benefit criteria such as safety and resiliency in order to further enhance the
2 GPM and support the need for additional investment in the grid. At this time, it is
3 the Company's intention to incorporate additional refinements of the investment
4 analysis process into its next rate case.

5

6 **Q38. Is it reasonable to adopt AG-MN Witness Alvarez's recommendation (page 49,**
7 **lines 15-16) to utilize a risk-informed benefit cost analysis, similar to the one**
8 **used in California, for the next DGP or rate case?**

9 A38. No. Witness Alvarez proposes using the risk-informed decision-making (RIDM)
10 framework, such as what California uses for its safety investments that are primarily
11 intended to address large scale risks such as wildfires and the associated Public
12 Safety Power Shutoffs (PSPS), catastrophic earthquake, hydro dam failures, cyber-
13 attacks on the critical energy infrastructures, and other potential public safety risks.
14 Witness Alvarez's testimony omits the history of the long journey that evolved
15 from the initial Safety Model Assessment Proceeding (S-MAP) that started nearly
16 a decade ago in parallel with the Risk Assessment and Mitigation Phase (RAMP)
17 proceedings as the precursor to their General Rate Case proceedings. By its own
18 account, the California Public Utility Commission's staff shared in its report that:

19 "...the RDF's [Risk-based Decision Making Framework]
20 decade in existence notwithstanding, a substantial amount of
21 work remains to be done to seamlessly integrate the risk-
22 based decision-making framework into utility General Rate
23 Cases. At present, the rapid clip at which utility safety-
24 related risk mitigation expenditures are growing points to an
25 unsustainable trend."¹³

26

¹³ https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/paper_final_june_2022_cpuc_rdf_crri.pdf, page 13

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1 In studying the historical evolution of California's RAMP filings, and specifically,
2 this methodology for evaluating safety and reliability plans, the Company draws
3 the following conclusions:

- 4 1) The framework has been developed over the course of a decade and has
5 evolved through many iterations.
- 6 2) The development has been led by the California PUC and based on joint
7 working sessions between the utilities.
- 8 3) The framework is applied to all large IOUs in the state.
- 9 4) The framework is very complex and has both quantitative and qualitative
10 metrics.

11
12 It would not be reasonable to adopt another state's risk-informed cost-benefit
13 analysis in a short period of time and without due diligence, which would omit the
14 opportunity to tailor the framework to the unique needs of the state of Michigan.
15

16 **Q39. Does the information in this instant case provide a reasonable and prudent**
17 **method for evaluating investments?**

18 A39. Yes, even as the Company works through BCA enhancements for future DGPs and
19 rate cases, the information submitted in this instant rate case provides a holistic
20 view of both project benefits and costs that support the Company's proposed
21 investments. Furthermore, the GPM is a sound method for evaluating the relative
22 benefits of different investments on safety, reliability, capacity, and equity.

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Rebuttal Issue 6: Global Prioritization Model (GPM)

Q40. What concerns does AG-MN Witness Alvarez express regarding the Company's GPM model?

A40. Witness Alvarez's concerns are:

- 1) The GPM does not answer the "important questions" about selecting strategic investments (page 45, lines 8-13)
- 2) The GPM is "subjective" and is "not data-driven" (page 46, lines 1-3, 12-14)
- 3) Failing to include the tree trimming program in the GPM is problematic (page 48, lines 1-6)
- 4) GPM evaluates both projects and programs together (page 47, lines 15-22)
- 5) GPM scores can be manipulated (page 46, lines 15-17)
- 6) GPM does not provide a "baseline" for reference (page 46, lines 4-12)

Q41. Does the Company agree that AG-MN Witness Alvarez's concerns have a material impact on the model's ability effectively support capital investments?

A41. No. The Company disagrees with each of these claims in whole or in part, as well as his recommendation to question the use of the GPM based on those claims. Each concern will be discussed in turn below.

Q42. What does AG-MN Witness Alvarez believe are the important questions the GPM should answer?

A42. The first concern is whether the GPM answers the "important questions" he asked about grid investments. As stated on page 45, lines 8-12 of Witness Alvarez's testimony: "There are important questions to be answered when making decisions

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1 about discretionary investments. These include 1) Do the benefits to customers
2 from the project or program exceed the program's costs to customers? 2) For
3 programs, what is the optimum geographic extent of deployment (i.e., on which
4 circuits or in what circumstances are the benefits more likely to deliver benefits in
5 excess of costs)? and 3) For programs, what is the optimum timing/deployment
6 speed?"

7

8 **Q43. Does AG-MN Witness Alvarez provide any support as to why these three**
9 **specific questions are required to be answered by the GPM or any investment**
10 **support tool?**

11 A43. No. There is no citation or reference as to whether these questions, and not other
12 questions, should be part of a standard decision-making process employed in
13 distribution planning, or if they were developed with any discussion with the
14 Commission, the utility, or other stakeholders. In some cases, the questions may
15 not even be applicable. For the PTMM program, for instance, there is no planned
16 geographic boundary for its extent as the best utility practice would be to inspect
17 all poles in the entire system.

18

19 **Q44. What is the basis of the Company's process for evaluating strategic**
20 **distribution investments?**

21 A44. As discussed in both the 2021 DGP and 2023 DGP, and mentioned briefly in
22 testimony above, the Company utilizes the Department of Energy (DOE) DSPx grid
23 modernization framework as part of the planning process. The first step of the
24 planning process is to define the objectives for grid investments.¹⁴

¹⁴ *Modern Distribution Grid (DSPx)*. (2019 November) Pacific Northwest National Lab. [Modern-Distribution-Grid Volume I v2 0.pdf \(pnnl.gov\)](#)

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1 **Q45. How did the Company define the objectives for distribution investments?**

2 A45. The Company adopted its planning objectives of 1) Safe, 2) Reliable and Resilient,
3 3) Affordable, 4) Customer Accessibility and Community Focus, and 5) Clean.
4 These were developed to be aligned with the objectives the Commission stated in
5 Case No. U-20147¹⁵. The Commission's objectives are Safety, Reliability and
6 Resilience, Cost Effectiveness and Affordability, and Accessibility. The GPM
7 measures project benefits across ten dimensions which are mapped to DTE
8 Electric's five planning objectives as was discussed in my revised direct testimony
9 on page 57 (Table 6) and is also provided below as Table 1 for convenience. The
10 benefits included in the GPM were selected not only because they meet a grid or
11 customer need, but also because they align with the overall objectives for the grid.

12

13 **Table 1 GPM Impact Dimensions and Planning Objectives**

		Planning Objectives				
		Safe	Reliable and Resilient	Affordable	Clean	Customer accessible and community focus
GPM Impact Dimensions	Reduce Electrical Hazards	✓		✓		
	Overload Relief	✓	✓	✓	✓	✓
	SAIDI	✓	✓	✓		
	SAIFI		✓			
	Regulatory Compliance	✓	✓			
	Major event risk	✓	✓	✓		
	Capacity Relief		✓		✓	✓
	Investment in EJ communities					✓
	O&M Avoidance			✓		
	Capital Avoidance			✓		

14

¹⁵ August 20, 2020 Commission order in U-20147, pp 36-38 ([mi-
psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000DcfWRAAZ](https://psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000DcfWRAAZ))

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1 **Q46. AG-MN Witness Alvarez states that “DTE’s GPM purports to rank capital**
2 **projects and programs based on their ability to reduce risk, from highest to**
3 **lowest.”¹⁶ Is this an accurate assessment of the GPM model?**

4 A46. No. The Company characterizes the impact dimensions used in the GPM as benefits
5 to the customer or grid. Some dimensions, such as “major event risk”, do measure
6 risk. The Company does not characterize the other benefits projects bring, such as
7 improved reliability, additional capacity, investment in environmental justice (EJ)
8 communities, and reduction of reactive cost as ‘risk reduction’.

9

10 **Q47. Do the set of impact dimensions included in the GPM lead to problematic**
11 **overlapping or double counting of benefits, as AG-MN Witness Alvarez**
12 **states¹⁷?**

13 A47. No. The specific impact dimensions Witness Alvarez references, “overload relief”
14 and “capacity relief” do not double count. “Major event risk”, “SAIDI”, and
15 “SAIFI” measure different aspects of customer reliability.

16

17 **Q48. Does the GPM double count benefits related to loading and capacity as AG-**
18 **MN Witness Alvarez claims?**

19 A48. No, these “overload” and “capacity” metrics were explained in the 2023 DGP in
20 Section 12.1. “Overload” refers to equipment which will operate above its rating
21 during peak loading under normal conditions. For example, a cable serving a circuit
22 has a measured load at peak that exceeds the capacity of that cable. “Capacity”
23 measures capacity constraints that exist in the event of a failure and include
24 substations operating over firm or violations of subtransmission planning criteria.

¹⁶ Alvarez DT, p. 45, lines 15-16

¹⁷ Alvarez DT, p. 45, lines 21-23

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1 For example, in a two-transformer substation, both transformers could be operating
2 under their ratings in normal circumstances and would not have an ‘overload relief’
3 score, however, in the event of a transformer failure, if the other transformer is
4 unable to serve the entire substation on its own, it would receive a “Capacity” score,
5 assuming the project in the GPM corrected the capacity concern.

6

7 **Q49. Do the GPM dimensions related to reliability and major event risk measure**
8 **different things?**

9 A49. Yes. “Major event risk”, “SAIDI”, and “SAIFI” dimensions all serve different
10 purposes. Major event risk provides a framework to prioritize investment that
11 would avoid large outages from substations failures. SAIDI and SAIFI
12 improvements are mostly aligned with reducing outages on circuits (overhead
13 outages and URD outages). Additionally, the Company added SAIFI to the GPM
14 in this iteration to complement SAIDI and provide a more complete picture of the
15 reliability experience. Some customers may experience a few long duration outages
16 which would be reflected by SAIDI improvements. Others may experience short
17 but frequent outages which would be reflected by SAIFI improvements. Both
18 duration and frequency measurements are relevant to customer reliability.

19

20 **Q50. How does AG-MN Witness Alvarez characterize the data used to calculate**
21 **GPM scores?**

22 A50. His second concern is the claim that “most of these inputs are not data-driven (i.e.,
23 based on historical experience, research or pilot results), but based on subjective

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1 GPM user assessments”.¹⁸ In addition, he states that “subjective inputs outweigh
2 data-driven inputs”.¹⁹

3

4 **Q51. Is this an accurate assessment of the inputs to the GPM?**

5 A51. No. The Company would classify information in the GPM as either a) “objective”
6 or b) “based on subject matter expertise”. Objective data is based on a measurement
7 or observation and would not generally require any additional judgement or input.
8 Examples of this type of data are reliability data (SAIDI and SAIFI), wiredown
9 data, loading data, equipment ratings, event volume, and historical costs per event.
10 Other scoring may fall into the latter category and be based on the assessment of
11 people with specific expertise in the field.

12

13 **Q52. How would the Company classify the data used in the GPM?**

14 A52. The Company would classify the inputs shown in Table 2 below as primarily
15 objective.

16

Table 2 Classification of GPM Inputs

17

Objective Inputs

- Historical reliability performance
- Historical wiredown performance
- Loading data
- Equipment ratings
- Stranded load calculations
- Demographic data such as inputs to the MiEJ Screen tool
- Historical trouble event volume
- Historical average costs per event
- Projected improvements in reliability, event volume, etc

Inputs based on subject matter expertise

- Scoring methodologies which combine multiple elements into a single value such as:
 - Asset health ratings
 - Load relief ratings
 - Overall MiEJ Screen score
- Assessment of whether investment meets regulatory compliance goals

18

¹⁸ Alvarez DT, p. 46, lines 2-3

¹⁹ Alvarez DT, p. 46, lines 12-13

Line
No.1 **Q53. What is an example of an input based on subject matter expertise?**

2 A53. Asset health assessments and scoring frameworks to rate key pieces of distribution
 3 equipment can be based on subject matter expertise. An example of how the various
 4 types of switchgear on the DTE Electric system are scored by equipment engineers
 5 is shown below in Figure 2 and were provided in discovery. The Company's
 6 equipment engineers, who have decades of experience operating, maintaining, and
 7 repairing DTE Electric's equipment identified the key aspects of switchgear which
 8 have historically caused issues. The experts in this field have identified nine
 9 different criteria which reflect previous challenges with the equipment, and assign
 10 scoring based on their judgement of the likelihood and severity of failure. The fleet
 11 of 250 switchgear lineups is scored based on this consistent methodology. Note,
 12 that while this method is subjective, it is quantitatively based.

13

14

Figure 2 Switchgear Asset Health Scoring

Inputs (to the raw score):					
DESIGN TYPE	DESIGN TYPE Score		NO SPARE PROPERTY		Asbestos Control Wiring
Across-the-Aisle	5		Yes	0	Yes 1
Single-Bus, Single Row (Outdoor Truck)	5		No	2	No 0
Transfer Bus/Aisleway	4				
Single-Bus, Two-Feeder	0		AGE	Age Score	
Single-Bus, Single Row/PDC	0		0	0	
Double-Bus, Two-Tier w/o PDC	1		10	0	
Double-Bus, Two-Tier/PDC	0		20	0	
Single Feeder	4		30	2	
			40	3	
Year			50	4	
2013			60	5	
			70	6	
Number of CALVERT BUS	CALVERT BUS Score		PARTS	No Parts Score	Total Risk Score = Modify
0	0		Spare Parts Available	0	*Time to Repair Score = All have a score of 12 due to t wh
1	1		No Spare Parts	3	Last Data update: 2/3/2021
2	2				
Breaker Racking			PREVIOUS FIRE		
Open Door	1		Yes	3	High Asset score 10 or above Westinghouse Cornel : ITE 15HK250
Closed Door	0		No	0	Elevated Asset score 1-9
					Acceptable Asset score 0
OPERATING ISSUES			Each of these categories are summed for their respective switchgear to develop the overall raw score.		Total Plant:
Yes	6				
No	0				

15

16 **Q54. What is the Company's assessment of the use of objective versus subject**
 17 **matter expert inputs to the model?**

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1 A54. Table 3 below is an analysis of all 138 projects scored in the GPM, with the total
2 score by dimension and the total score for all evaluated projects shown. The five
3 bolded dimensions (Reduce Electrical Hazards, SAIDI, SAIFI, O&M Avoidance
4 and Capital Avoidance) are entirely calculated based on objective information and
5 contribute 45% of the overall scoring. If we include the Investment in EJ
6 Communities dimension, which uses the MiEJ Screen score for the investment area
7 and was developed by the Department of Environment, Great Lakes and Energy
8 (EGLE), and contributes 18% to the total, 63% of the total scoring in the GPM is
9 objective. The dimensions that include some subject matter expertise, such as
10 Overload Relief and Capacity Relief, are also based on objective inputs such as
11 measured load and equipment ratings. In short, the Company's analysis of the data
12 in the GPM shows that Witness Alvarez's claim that GPM inputs are largely based
13 on subjective assessment and is not data-driven are incorrect.

Table 3 Analysis of GPM input data

Impact dimension	Objective Inputs	Subject Matter Inputs	Total by dimension	% of total
Reduce Electrical Hazards	x		3,016	11%
Overload Relief	x	x	3,999	15%
Capacity Relief	x	x	3,019	11%
Regulatory Compliance		x	400	1%
Investment in EJ communities	x	x	4,731	18%
Major Event Risk	x	x	2,740	10%
SAIDI	x		2,881	11%
SAIFI	x		2,352	9%
O&M Avoidance	x		2,476	9%
Capital Avoidance	x		1,289	5%
Total Score			26,904	

17

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1 **Q55. In AG-MN Witness Alvarez’s alternative recommendation to the GPM, the**
2 **risk-informed benefit cost methodology used in California for the four**
3 **investment owned utilities RAMP filings, what benefits are monetized?**

4 A55. Projects in these filings are evaluated on 1) Safety – using the Department of
5 Transportation’s value of statistical life (VSL) and 2) Reliability – using the LBNL
6 ICE calculator.²⁰

7
8 **Q56. Does this alternative method avoid non-objective assumptions for safety and**
9 **reliability?**

10 A56. No, both values were developed based on subject matter expert (SME) analysis. As
11 an example, the ICE calculator, which the Company uses in BCAs presented in this
12 case, is based on survey data of both residential and commercial customers and asks
13 questions about willingness to pay to avoid outages. The survey data was then
14 shaped by SMEs to create the ICE calculator formula(s). This is not to say that the
15 Company disagrees with the ICE calculator values, in fact the Company is actively
16 engaged with LBNL on the development of ICE 2.0, rather it demonstrates that the
17 ICE calculator, an industry standard tool for measuring reliability, is an example of
18 using expert judgement to value a non-monetary benefit. In any complex BCA
19 incorporating multiple benefits, it is nearly impossible to avoid using some degree
20 of subject matter expertise to arrive at a benefit cost ratio result.

21

22 **Q57. Does AG-MN Witness Alvarez express concern that the tree trimming**
23 **program is not evaluated in GPM?**

²⁰ See California PUC R20-07-013, Dec 15, 2022, Decision 22-12-027, Phase II Decision Adopting Modifications, pp35-38. <https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=500014668>

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1 A57. Yes, his third concern about the GPM, as he states on page 48, is that the GPM is
2 not used to score the tree trimming program.

3

4 **Q58. Do you agree with this concern?**

5 A58. No. When first developing the GPM, the Company did run the tree trim program
6 through the model. As stated in the Company's first Distribution Investment and
7 Maintenance plan, "Tree trimming to the enhanced specification...continues to
8 provide the highest customer benefits of any program in the five-year investment
9 portfolio"²¹. Tree trimming is an effective program; the Company will continue to
10 complete the surge and maintain the cycle. However, at this point the Tree Trim
11 program is concluding the Surge and transitioning to maintaining our system, tree
12 trimming should be considered a required, fundamental, baseline activity. It is also
13 an O&M expense, therefore including it in the GPM does not aid in prioritizing
14 capital projects.

15

16 **Q59. Does AG-MN Witness Alvarez express concern that projects and programs**
17 **are prioritized together in the GPM?**

18 A59. Yes, a fourth concern, stated on page 47, lines 15-22, is that the GPM does not
19 distinguish between projects and programs, and does not factor into program
20 scoring the potential variability of impacts a program will have on different circuits.

21

22 **Q60. Does the Company share AG-MN Witness Alvarez's concerns about including**
23 **both projects and program in the GPM for prioritization?**

²¹ DTE Electric's Five Year (2018-2022) Investment and Maintenance plan, filed in docket U-18014 on 1/31/2018, p18

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1 A60. The Company acknowledges that it is challenging to compare projects and
2 programs, which is one of the foundational reasons the GPM was developed. Prior
3 to the development of the GPM, the Company did not have an objective
4 standardized method that accounted for both relative benefits and costs and allowed
5 for comparison of programs, large projects, and small projects on a level playing
6 field. For programs specifically, it would be impractical to prioritize investments if
7 each of the thousands of projects for specific distribution circuits were prioritized
8 individually for every applicable program. Instead, program benefits are calculated
9 at the aggregate for a 5-year period and ranked. For many programs, including the
10 programs Witness Alvarez cites (PTMM, Distribution Automation, and 4.8kV
11 Hardening), the benefits are calculated from the Reliability Model based on the
12 specific planned circuits that will receive the program investments. Each individual
13 program uses prioritization criteria relative to its strengths to identify circuits which
14 will receive the highest benefit from the program. Programs may defer or skip
15 altogether circuit where benefits are found to be low within the program
16 prioritization. Both the PTMM BCA spreadsheet and the Distribution Automation
17 prioritization methodologies have been provided as evidence in this case to support
18 how investments are prioritized within programs.

19

20 **Q61. Does AG-MN Witness Alvarez make claims that program and project score**
21 **can be manipulated?**

22 A61. Yes, a fifth concern is summarized on page 46 lines 15-17: "A model user can get
23 the GPM outputs he or she desires for a particular project or program simply by
24 manipulating subjectively-assessed model inputs for the project or program."

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1 **Q62. How does the Company prevent results in the GPM from being manipulated?**

2 A62. The scores in the GPM cannot be manipulated in the way Witness Alvarez claims
3 for multiple reasons. First, as already discussed, most of the inputs to the model are
4 based on objective measured data such as historical reliability, measured loading,
5 and external inputs such as the MiEJ Screen tool. Second, the methods used to
6 calculate scores based on these objective inputs have been consistent over time and
7 are applied uniformly to the projects and programs that are being evaluated. Third,
8 the Company has requested feedback from stakeholders during technical
9 conferences and DGP filings on suggested changes to weightings and assumptions.
10 Lastly, and most importantly, the entire model has been provided as a workpaper
11 in this case, Exhibit A-43, Schedule HH4 - WP AJK U-21534 GPM in my rebuttal
12 testimony, so all assumptions and weighting can be examined. The Company
13 intends to provide the model in future DGPs and rate cases so that any year over
14 year changes will be transparent.

15

16 **Q63. Do you have any additional comments about AG-MN Witness Alvarez's claim**
17 **that the GPM can be manipulated?**

18 A63. Yes. The Company is under considerable pressure from its customers, regulators,
19 and elected officials to quickly improve reliability. The Company's incentives are
20 firmly aligned with identifying the programs that deliver the most benefits per
21 dollar and has no interest or reason to engage in model manipulation.

22

23 **Q64. Does AG-MN Witness Alvarez's testimony suggest using alternative project**
24 **ranking methodologies that are fundamentally flawed and should not be used?**

Line
No.

1 A64. Yes, the sixth and last concern the Company will address is Witness Alvarez's
2 assertion that the GPM does not include a proper 'baseline'. The testimony goes on
3 to discuss two flawed alternative methodologies.
4
5 The first flawed methodology is assuming that the percent reduction from the
6 baseline should be factored into the GPM scoring. He states on page 46 lines 8-12:
7
8 "Risk reduction estimates (such as a projected reduction in customer minutes
9 interrupted) are input with no indication of the scale of the reduction relative
10 to current state risk. For example, does a 100,000 minute reduction in
11 customer minutes interrupted represent a 2% reduction from the baseline or a
12 50% reduction from the baseline?"
13
14 To start, the GPM does, in most cases, include both the baseline and the
15 improvement, contrary to Witness Alvarez's assertion. An example is shown in
16 Table 4 below, which is in the "Reliability – SAIDI" tab of the GPM, Exhibit A-
17 43, Schedule HH4 - WP AJK U-21534 GPM. As seen in the table, most investments
18 include Customers Minutes Interrupted (CMI) "CMI Before" as the baseline. These
19 values are derived from historical reliability of the circuits being addressed by the
20 specific GPM projects. The baseline for programs, such as PTMM, CEMI, 4.8kV
21 Hardening, and Distribution Automation, is the system wide historical SAIDI
22 performance. More importantly though, the key measurement of risk reduction is
23 "CMI Avoided per \$M invested", which has no correlation to the percentage
24 reduction from the baseline. Given a finite budget, the projects that will provide the
25 most overall benefit from this tab of the GPM are those with the highest CMI per
26 \$M invested, not those with the highest CMI compared to a baseline, as Witness
27 Alvarez suggests. In fact, using Witness Alvarez's example, assuming equal project
28 costs, a 100,000 minute reduction has the same benefit to our system regardless if

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1 it's a 2% reduction or a 50% reduction from the baseline. However, if the 100,000
2 minutes from the 2% project was half the price of the 100,000 minutes from 50%
3 project, the GPM (and the Company) would select investment in the 2% project.

4 **Table 4 'Reliability-SAIDI' tab of GPM**

RowID	Project ID	Project/Program Name	Capital Investment	CMI Before	CMI Savings	CMI Avoidance per \$M Invested	Score
1	2005	ADMS: DMS/OMS	\$ 91,844,058	0	98,611,830	\$ 1,073,688	752
2	1015	40 kV: Automatic Pole Top Switch	\$ 31,800,000	0	16,186,250	\$ 509,002	356
3	2007	Frequent Outage Program (CEMI)	\$ 48,049,745	0	22,926,268	\$ 477,136	334
4	2008	Pole and Pole Top Maintenance and Modernization (PTMM)	\$ 715,450,000	0	297,893,299	\$ 416,372	291
5	2017	Distribution Automation	\$ 1,162,788,221	0	346,230,878	\$ 297,759	208
6	20201053	4.8 kV CC: Hawthorne Relief and Circuit Conversion	\$ 94,029,812	23,056,762	19,598,248	\$ 208,426	146
7	2001	4.8 kV Hardening	\$ 259,000,000	0	27,566,077	\$ 106,433	75
8	2029	4.8 kV CC: ISO Conversion Program	\$ 25,350,000	0	2,520,996	\$ 99,448	70
9	20230004	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	\$ 2,627,140	285,526	242,697	\$ 92,381	65
10	2004	URD Replacement Program	\$ 72,041,398	0	5,151,733	\$ 71,511	50
11	20191025	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	\$ 330,838,051	22,846,946	19,419,904	\$ 58,699	41
12	20201054	4.8 kV CC: Belleville Substation and Circuit Conversion	\$ 11,385,184	699,141	594,270	\$ 52,197	37
13	20230006	4.8 kV CC: Zenon Circuit Conversion Phase 2	\$ 155,800,000	7,907,726	6,721,567	\$ 43,142	30
14	20230013	4.8kV CC: Hemlock Decommissioning and Circuit Conversion	\$ 68,039,683	3,352,653	2,849,755	\$ 41,884	29
15	2002	Breaker Replacement Program	\$ 70,799,000	0	2,916,000	\$ 41,187	29
16	20191024	4.8 kV CC: Royal Oak Substation and Circuit Conversion	\$ 547,652,366	24,629,899	20,935,414	\$ 38,228	27
17	20230019	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversio	\$ 43,951,541	1,968,047	1,672,840	\$ 38,061	27
18	20191037	4.8 kV CC: Birmingham Decommissioning and Circuit Convers	\$ 53,720,709	2,387,430	2,029,315	\$ 37,775	26
19	20201064	4.8kV CC: Rochester Decommissioning and Tienken Relief	\$ 27,790,000	1,197,949	1,018,257	\$ 36,641	26
20	20191082	8.3 kV CC: Pontiac Overhead/Underground Conversion	\$ 174,407,073	6,926,375	5,887,419	\$ 33,757	24

5
6 **Q65. What is the second methodology that AG-MN Witness Alvarez proposes?**

7 A65. Witness Alvarez describes "Risk-Informed Decision Support" on pages 49-50
8 along with an example shown on page 50 of how to select the optimal investments.
9 His conclusion is that the optimal solution is retaining (investing in) projects 1, 2
10 and 3, which is mathematically incorrect. The Company conducted its own analysis
11 to optimize the hypothetical portfolio to demonstrate why his methods are incorrect

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and lead to the wrong conclusion. When ranked on benefit (Risk Reduction) vs cost (PVRR), the far right column in the table below, the optimal portfolio would select Projects 1, 5, 3 and 2, in that order, and project 5 should certainly be prioritized before projects 2 and 3. See Table 5 below for calculations. If the Company GPM methodology is used, project 5 has the second highest score and it would be apparent that it should be selected over projects 2 and 3 because it clearly provides the most value per dollar invested. Witness Alvarez's method failed to achieve this result and should be rejected.

Table 5 Optimal analysis of project portfolio

Project	PVRR (\$M)	Risk Reduction	Risk Reduction per \$M PVRR
1	\$ 24	180	7.6
2	\$ 49	147	3.0
3	\$ 39	125	3.2
4	\$ 88	79	0.9
5	\$ 15	74	4.9
6	\$ 40	68	1.7
7	\$ 34	53	1.6
8	\$ 19	41	2.1

Rebuttal Issue 7: Reliability Model

Q66. AG-MN Witness Alvarez criticizes the Company's use of the Reliability Model when he claims that "DTE uses the Reliability Model's improvement projections to justify the size of its strategic capital program budgets. By implication, the Model's reliability improvement projects are also intended to justify most of the Company's request to extend and expand rider IRM"²²? Does the Company agree with his statement?

²² Alvarez DT p. 53, lines 2-5

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No.

1 A66. No. The Reliability Model is just one component of the support for the six reliability
2 improvement programs/projects that are included (Tree Trimming, Distribution
3 Automation, PTMM, Customer Excellence, 4.8kV Hardening, and 4.8kV
4 Conversion), it is not the sole justification. Primary justification for the six
5 programs and projects is found in testimony presented by Company Witnesses
6 Deol, Hartwick, Elliott-Andahazy, and Steudle (for tree trimming), in Capital
7 Summaries (Exhibit A-23, Schedule M3-M5) with detailed information on project
8 drivers, scope and benefits, and in the GPM. Additionally, the model is not
9 “intended to justify most” of the IRM investments, as areas of investments such as
10 Breakers, URD, and Subtransmission Redesign and Rebuild projects are not
11 included in the Reliability Model. 4.8kV Conversion projects, while included in the
12 model from a reliability benefit perspective, are typically driven by capacity or
13 aging equipment needs, which are not reflected in the model.

14

15 **Q67. What critique does AG-MN Witness Alvarez provide with regard to the**
16 **Reliability Model?**

17 A67. Witness Alvarez provides four pieces of feedback on how this type of reliability
18 modeling should be performed (pages 53-57), including:

- 19 1) Project and program analysis that was used to populate the reliability
20 improvements within the model should not have been calculated using a
21 ‘differences of differences’ approach. (page 54)
- 22 2) The model should separate tree trim impacts from the impact of strategic capital
23 programs. (page 53)
- 24 3) The model should use multiple years of baseline reliability to account for
25 weather variation. (pages 55-56)

Line
No.

1 4) The model should use accurate units to project reliability improvements. (pages
2 56-57)
3

4 **Q68. Does the Company agree with the feedback from AG-MN Witness Alvarez?**

5 A68. Yes, in fact all four of those components describe how the Reliability Model
6 actually works.
7

8 **Q69. Based on his testimony, how does AG-MN Witness Alvarez assume benefits
9 are being calculated for use in the model?**

10 A69. Witness Alvarez assumes that DTE Electric is using a ‘differences of differences’
11 approach and discusses drawbacks of this approach for modeling on pages 54-55.
12 Using this methodology, the comparison is between a control group and a test
13 group. The measured benefits would be the difference between the before and after
14 performance of the control group (i.e., Difference 1) and the before and after
15 comparison of test group (i.e., Difference 2). His primary complaint is that he
16 believes the test group has had both tree trimming and a capital investment, whereas
17 the control group has neither, and thus the results are combining the impact of both
18 tree trimming and the capital investment.
19

20 **Q70. Does the Company use the ‘differences of differences’ approach for modeling
21 reliability benefits in the reliability model?**

22 A70. No. The reliability model uses a different type of analysis that was provided in
23 discovery and included in Exhibit A-43, Schedule HH6 - MNSCDE-12.8b -
24 Reliability Program Analysis.

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1 **Q71. How are the projected reliability benefits calculated for use in the Reliability**
2 **Model?**

3 A71. Table 6 for 4.8kV Hardening is shown below as an example. The “before”
4 performance is the event volume the year 4.8kV hardening work is completed on a
5 group of circuits and has a 0% reduction in events as the baseline. The “after” period
6 consists of the years after the work has been performed and will have a negative
7 number indicating a reduction in event volume from the baseline. For example,
8 work that was completed a few years ago, such as 2018, has four ‘after’ years,
9 whereas work completed in 2021 currently only contains analysis on a single after
10 year. Because the comparison is a “before” and “after” on the same set of circuits,
11 there is no control group as Witness Alvarez assumes in his testimony, and all the
12 circuits have undergone tree trimming as a pre-cursor to 4.8kV Hardening work. If
13 anything, some benefits may accrue to the circuits in the “before” year since it is
14 the year work is being done, which could have the result of lowering the starting
15 point for events tracking, and thereby understating the benefits of the program. The
16 table is meant to be read left to right with the third column, listing the years 2017-
17 2021, representing the years a group of circuits were completed. Take 2020 (second
18 row from the bottom) as an example, 30 circuits were completed that year and the
19 first year post hardening (2021 – second column from the right) the analysis shows
20 75% improvement for this group of circuits.

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1

Table 6 4.8kV Hardening Event Reduction

4.8kV Hardening								
% change in events								
	# of Circuits		2017	2018	2019	2020	2021	2022
0%	0	2017	0%	0%	0%	0%	0%	
7%	5	2018		0%	-76%	-90%	-86%	-71%
25%	18	2019			0%	-79%	-78%	-76%
42%	30	2020				0%	-75%	-78%
26%	19	2021					0%	-84%

2 **Q72. Does AG-MN Witness Alvarez believe that the Reliability Model mixes the**
3 **impact of tree trim events and non-tree trim events?**

4 A72. Yes. On page 53, lines 15-17 he states “DTE did not attempt to isolate the impact
5 of tree trimming from the impact of strategic capital program spending when
6 determining historical reliability performance of the programs.”

7
8 **Q73. Did DTE Electric isolate the impact of tree trimming from strategic capital**
9 **improvements in the Reliability Model and supporting analysis?**

10 A73. Yes, this isolation is incorporated in two ways. First, as also was provided in
11 MNSCDE-12.8b, Exhibit A-43, Schedule HH6 - MNSCDE-12.8b - Reliability
12 Program Analysis, the benefits are calculated separately for tree-related and non-
13 tree related events. The Tree Trimming benefits analysis only looks at tree-related
14 event reduction, whereas the capital programs such as 4.8kV Hardening only look
15 at non-tree related event reduction. Secondly, the circuit-level baseline is calculated
16 and projected separately for tree and non-tree related outages. This was stated in
17 my revised direct testimony in Q85 (bold added for emphasis): “Each circuit has a
18 baseline of reliability performance based on five years of historical, non-MED
19 event volume. **Events are further divided into tree and non-tree**, single and

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1 multiple, and outage and non-outage”. In other words, the model completely
2 isolates tree and non-tree related events to project reliability impacts.

3

4 **Q74. Does the model use multiple years of data to account for weather variability?**

5 A74. Yes, as also shown in Table 6 above, the reliability benefit assumptions use multiple
6 years of weather data in the baseline by using circuits which have had treatment
7 across multiple years. The baseline, in this example, includes weather from 2018-
8 2021. Additionally, the model uses non-MED event volume as the basis for
9 calculations, which is likely less volatile to weather impacts than either all-weather
10 events or non-MED reliability metrics such as customer minutes interrupted.

11

12 **Q75. AG-MN Witness Alvarez states on page 58, lines 2-5 that “As costs typically**
13 **go up over time, not down, particularly in these inflationary times, I am**
14 **concerned that the number of “units completed” in the model are exaggerated**
15 **relative to the number of units the Company will be able to complete for the**
16 **capital budgets indicated.” Does the Reliability Model use accurate counts of**
17 **units aligned to the Company’s investment plan?**

18 A75. Yes, the model uses the same units and circuits for projecting reliability input as
19 were provided in this instant case testimony, such as Table 12 in Witness Elliott
20 Andahazy’s revised direct testimony, and multiple discovery responses like Exhibit
21 A-53 Schedule RR1. PTMM, 4.8kV Hardening, Distribution Automation, and
22 4.8kV Conversion, and Tree trimming circuits selected in the model for 2024 and
23 2025 are aligned with the execution plan for those programs and projects.

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1 **Q76. Does AG-MN Witness Alvarez provide an analysis on the unit costs that he**
2 **uses to support a claim that the units in the model are overstated?**

3 A76. Yes, Witness Alvarez presents a table, on pages 56-57 of his direct testimony, with
4 unit cost comparisons in 2024 and the last year data is available and claims
5 significant reductions in unit costs imply that the units used in the Reliability Model
6 cannot be achieved.

7
8 **Q77. Does the unit cost analysis AG-MN Witness Alvarez provides have flaw or**
9 **errors in it?**

10 A77. Yes, there are three different factors impacting the calculations in this table that
11 prevent us from drawing any conclusions from the analysis. First, when dividing
12 total investments by units to get cost per unit, the costs Witness Alvarez used are
13 off by a factor of ten, and therefore the whole table is off by an order of magnitude.
14 For example, the average costs to convert a mile of 4.8kV in 2024 is approximately
15 \$2.5 million using the units in the Reliability Model and the investments in A-12
16 Schedule B5.4, not \$256,000 as listed in the table. Secondly, Witness Alvarez does
17 not include all costs in his calculations for future years. For 4.8kV Conversions, he
18 stated in footnote 54, on page 56 that he used Exhibit A-33 Sch X1 (IRM), which
19 shows \$199 million in conversion investments in the proposed 2027 IRM. Not all
20 cost recovery for 4.8kV Conversions will occur through the IRM, so the costs he
21 used are only a subset of the total. The most complete description of the Company's
22 plans to convert the 4.8kV system, particularly for years beyond the test year of this
23 case, is the 2023 DGP. On page 117 of the DGP (Exhibit A-23, Schedule M8), the
24 projected 4.8kV capital investment in 2027 is \$372 million (significantly different
25 than the \$199 million used in the table calculations). Projections in the Reliability

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1 Model are based on the total investments in the distribution system and are agnostic
2 to the cost recovery mechanism (IRM vs rate case). Similar to his conversion costs
3 assumptions, Witness Alvarez uses partial or inaccurate cost information to
4 calculate Automation costs per unit, because funding for that program exists in both
5 the IRM and the rate case. Finally, his analysis fails to account for other
6 programmatic factors. For example, the 2026 investments in 4.8kV Hardening
7 consist almost entirely of construction of line miles. Other costs such as design and
8 tree trim generally occur the year prior. There are no costs in 2026 associated with
9 trimming or designing circuits for construction in 2027, as the program will be
10 complete. Therefore, a significantly lower and inaccurate for comparison cost per
11 unit would be expected. 4.8kV Conversion projects may also experience a lower
12 cost per unit in the future as the work mix will shift from CODI projects, which
13 include significant underground scope and less overhead miles, to projects outside
14 of CODI which typically involve more overhead rebuild. Given these three factors,
15 the analysis of the table cannot be used to draw any valid conclusion, much less
16 conclude that cost per unit in the reliability Model are exaggerated.

17

18 **Q78. Does the Company agree with AG-MN Witness Alvarez's position that that**
19 **model results are inaccurate if profits are not tied to model accuracy²³?**

20 A78. No, the Company does not agree. Placing profits at risk is completely unrelated to
21 the logical assumptions and math of the model, and this type of criticism offers no
22 constructive feedback or path forward on how to improve model accuracy.
23 Additionally, the Company cited weather variability as one rationale to not directly
24 tie potential future system performance to model output. While Witness Alvarez

²³ Alvarez DT, page 57, line 13-14

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1 states “there are ways to address this concern.” (page 57, line 14-15), he remains
2 silent on what any of those ways are.

3

4 **Q79. Does the Company plan to continue to evaluate and improve the Reliability**
5 **Model over time?**

6 A79. Yes, the Company will continue to measure reliability benefits of the modelled
7 programs and update expected benefits as additional data and analysis is available.
8 The Company may also add additional investment categories to the model, update
9 the degradation analysis, or add a factor in to account for more severe weather.
10 Lastly, if the data and modeling indicate that a program is not performing as
11 expected, the Company will also reevaluate that program for future investment.

12

13 **Rebuttal Issue 8: Investment Changes between the 2023 Distribution Grid Plan and**
14 **the Instant Rate Case**

15

16 **Q80. How do you respond to Staff Witness Becker recommendation (page 12, lines**
17 **18-21) to “...improve upon aligning spending plans between DGP and rate**
18 **case filings and instrut the Company to communicate its decisions to increase**
19 **or decrease spending in categories after DGP is filed.”?**

20 A80. The Company, in general, supports Witness Becker’s recommendation to improve
21 the alignment of investment plans between DGP and rate case filings. The
22 Company’s goal is to improve transparency into distribution system investment
23 plans and related investment projections for its regulators, customers, and other
24 stakeholders. However, there is a basis for the discrepancy in investment levels. A

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1 summary of explanations for the most significant changes in investments levels
2 between the 2023 DGP and the instant case are:

3 1. The \$107 million variance in **Emergent Replacement** for 2025 was largely
4 driven by the years used in the five-year inflation calculation. The 2023 DGP
5 calculated inflation based on 2017 – 2021, whereas the instant case was updated
6 to use calculated inflation based on 2018-2022. The Company will address this
7 misalignment in future DGP filings, however as the DGP and rate case timing
8 are typically not exactly aligned or on the same cadence, the most current filing,
9 either DGP or rate case, will likely continue to use a baseline using the most
10 recent available five-year timeframe.

11 2. The \$100 million variance in **Tree Trimming** is primarily due to a strategic
12 update that occurred post DGP filing that added an additional regulatory asset
13 request of \$87 million in the instant case, aimed at completing the surge by the
14 end of 2025.

15 3. The variance of \$71 million in **Infrastructure Resilience & Hardening** is
16 mainly due to the accelerated enhancement of the 4.8kV Hardening program,
17 targeting completion by the end of 2026. Additionally, the Company initially
18 forecasted a decrease in CEMI investments; however, given the recent
19 reliability performance of the DTE Electric system, the Company determined
20 that this program should continue at its existing funding level until reliability
21 sufficiently improves.

22
23 In the future the Company will work towards minimizing changes to planned
24 investments between the rate case and DPG filings, and when strategic changes are

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1 necessary post DGP filing, the Company will work with Staff to communicate these
2 changes with increased transparency.

3

4 **Q81. Staff Witness Becker proposed a “distribution plan annual update approach**
5 **in its comments to the Company’s 2023 DGP that could serve as a platform to**
6 **communicate changes in projected spend” (Page 12, lines 9-11). How do you**
7 **respond to this proposal?**

8 A81. The Company is willing to collaborate with Staff and develop a process, structure,
9 and requirements of proposed annual updates on changes to near-term investment
10 plans described in the DGP.

11

12 **Rebuttal Issue 9: Electric Vehicles (EVs) and Clean Energy Future Legislation**

13

14 **Q82. Do you agree with AG-MN Witness Alvarez that “...preparing the grid for**
15 **electrification, for example through conversions of 4.8 kV circuits to 13.2 kV**
16 **circuits, does not appear to be an urgent need.”²⁴?**

17 A82. No. The primary purpose for the conversions of 4.8 kV circuits to 13.2 kV circuits
18 in this rate case is to address *current* loading issues, as well as improve safety and
19 reliability. Refer to Company Witness Deol’s rebuttal testimony, pages 7 through
20 11, for further details on the reasons for conversions.

21 An additional benefit to conversion is that it prepares the grid for electric vehicles
22 (EVs) and distributed energy resources (DERs). In Commission Order U-21400,
23 page 12, it states the following:

24 “Beyond this primary focus on distribution reliability and
25 safety, the workgroup shall also consider challenges around

²⁴ Alvarez DT, page 20, line 13-15

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1 the readiness of utility distribution grids to effectively
2 accommodate and leverage the increasing and further
3 anticipated growth of distributed generation, EVs, and other
4 DERs.”

5 The outlook for EVs and DER adoption is anticipated to grow, and the Company
6 recognizes the need for the grid to be well-prepared ahead of the growth, and in
7 support of the growth. The Michigan Healthy Climate plan has a goal to “build the
8 infrastructure necessary to support two million electric vehicles on Michigan roads
9 by 2030”²⁵, approximately 40 times more than the amount of EVs currently
10 registered in Michigan²⁶. Preparing for that level of electrification will require
11 investment in the grid. See Company Witness Bennet’s rebuttal testimony for
12 further information on the Company’s Electric Vehicle forecast, pages 7-13.

13

14 **Q83. Do you agree with AG-MN Witness Alvarez that “...rooftop solar does not**
15 **typically require much distribution grid investment. Only utility-scale, rurally**
16 **located solar systems typically require significant distribution grid**
17 **investments...”²⁷?**

18 A83. No. Witness Alvarez cites his own experience and AG-MN Witness Stephens
19 experience as justification for the statement but does not supply any data or studies
20 for this claim. The Company has already invested and will continue to invest in grid
21 updates that are supportive of the integration of renewables including residential
22 and commercial solar installations. In addition to customer-funded updates that
23 may be required as part of the interconnection process, the Company has evaluated
24 and modified protection and automation schemes, incorporated bidirectional power

²⁵ Mi Healthy Climate Plan, available at <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan>, accessed August 14, 2024

²⁶ Alternative Fuels Data Center: Maps and Data, available at <https://afdc.energy.gov/data/10962>, accessed August 14, 2024 <https://afdc.energy.gov/data/10962>

²⁷ Alvarez DT, p.21, lines 1-3

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1 flow in load analysis and the evaluation of technology solutions to accommodate
2 the bidirectional flow, and invested in interconnection software, hardware,
3 communications, and control systems, to name just a few examples.

4

5 **Rebuttal Issue 10: CEO Witness Volkmann Table of Recommendations**

6

7 **Q84. Did CEO Witness Volkmann make recommendations regarding specific**
8 **recommendations to the Commission?**

9 A84. Yes, on page 28 of Witness Volkmann's testimony, he makes three
10 recommendations, which are summarized in the table below, along with DTE
11 Electric's response to his proposals.

12

13 **Table 7 Response to Witness Volkmann Recommendations**

Lines	Recommendation	DTE Electric Response
11-13	1) Provide enhanced reporting of circuit-level reliability program results (for) compared to the Company's reliability improvement projections.	The Company will continue to measure program effectiveness to refine and validate the Reliability Model which is used to perform reliability projections. The Company notes that it already does provide circuit level reliability performance, starting in 2023, as part of the MPSC reporting requirements and shown on the MPSC website ²⁸ , and that the Reliability Model projects individual circuit reliability. The Company is also open to continuing to work with CEO and other stakeholders if the Reliability Model methodology does not provide the information they are seeking.

²⁸ Distribution System Reliability Metrics, available at <https://www.michigan.gov/mpsc/consumer/electricity/distribution-system-reliability-metrics>, accessed August 15, 2024

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A. J. KRYSCYNSKI

U-21534

Lines	Recommendation	DTE Electric Response
14-16	2) Work with Staff and interested stakeholders to design a VPP pilot/demonstration project for resilience and peak load reduction use-cases using a third-party aggregator, and to include the pilot/demonstration in its 2025 DGP.	Witness Farrell discusses current demand response offerings and progress on third party aggregation engagement.
17-19	3) Work with Staff and interested stakeholders to define its approach for scaling up piloted technologies and incorporating [Non -Wires Alternative] NWA solutions into its distribution planning process. DTE Electric should explain the approach in its next DGP.	The Company screens load-related strategic investments for NWA opportunities and typically finds the load constraints that are being addressed are generally not suitable for NWA projects. The Company is committed to completing the pilots underway and communicating lessons learned in order to inform discussions on how to scale the piloted technologies.

1

2 **Q85. Did CEO Witness Volkmann make other requests specifically to DTE Electric**
3 **in his direct testimony?**

4 A85. Yes. Many of his requests are covered elsewhere in my rebuttal testimony or in the
5 testimony of other DTE Electric Witnesses. For brevity I've included DTE
6 Electric's response to his requests in the table below.

7

8

Table 8 Response to Witness Volkmann Requests

Page:Lines	Recommendation	DTE Electric Response
28:21-23	1) Provide additional information about EJ Community impacts in its next DGP, including how customers are benefitting from investments and confirming that these benefits are the ones the communities prioritize.	The Company commits to continuing to work with CEO to better understand the analysis being requested.

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A. J. KRYSCYNSKI

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Page:Lines	Recommendation	DTE Electric Response
29:1-2	2) Conduct one or more Technical Conferences to further explain its GPM to Staff and stakeholders and explain how it differs from a BCA.	The Company held a Technical Conference before the 2023 DGP was filed and is willing to hold additional conferences if the Commission, Staff, or Stakeholders find it valuable.
29:3-4	3) Conduct one or more Technical Conferences to help Staff and stakeholders understand the DA Prioritization Model's assumptions and calculations.	The Company is willing to hold technical conferences to explain the methodology used to prioritize if the Commission, Staff, or Stakeholders find it valuable.
29:5-7	4) Expand its Reliability Model to include the impacts from URD Replacement, Cable Replacement, Breaker Replacement, and Substation Risk projects and include the enhanced model in its next DGP.	The Reliability Model is based on groups of high volume of outage events, and reliability is projected at the circuit level. URD, Cable, and Breaker events are significantly lower volume and are not a good fit to be included in the model. It would add significant complexity without providing much additional clarity. Estimates for reliability impact for these are better done at a system-wide level. The Company is willing to meet and discuss the technical details with those stakeholders who are interested.
29:8-9	5) Collect and incorporate actual outage data to refine the assumptions in its Reliability Model.	This is referenced earlier in my rebuttal under the Reliability Model section. The Company will refine model assumptions as actual outage data is collected and analysis is performed.
29:10-12	6) Refresh its assumptions in the DA Prioritization Model with the actual customer interruption and outage duration impacts from automation as the data become available.	The Company will refresh the model assumptions with new data and learnings as long as the model remains in use.

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Page:Lines	Recommendation	DTE Electric Response
29:13-16	7) Expand the Company's application of its BCA methodology to its 4.8kV Conversion, Distribution Automation, Frequent Outage, Subtransmission Redesign & Rebuild, Breaker Replacement, URD Replacement, Cable Replacement, and Tree Trimming Surge programs.	Future BCA plans were discussed in my Cost Benefit Analysis section. The Company is exploring options to conduct BCAs on additional projects or programs.
29:17-18	8) Make necessary modifications to its outage management systems to begin incorporating actual DTE Electric failure data in its BCA methodology	The Company plans to continue to improve data collection through its OMS to provide a richer data source for BCAs and other analysis.
29:19-20	9) Consider partnering with LBNL to quantify the resilience impacts of DTE Electric's planned investments using POET, for inclusion in future BCAs.	See item 7) above. The value of resiliency is a benefit that could be considered in future BCA analysis, whether through POET, which the Company will explore in preparation for the next DGP, or other methodologies.
29:21-22	10) Modify its BCA methodology to reflect the full revenue requirements of investments.	The Company will consider this modification in future BCA efforts.

1

2 **Rebuttal Issue 11: Environmental Justice (EJ)**

3

4 **Q86. What recommendations have been made by Witnesses regarding the**
5 **Company's Environmental Justice (EJ) analysis?**

6 A86. Several Witnesses requested that the Company do more tracking and reporting of
7 EJ-related metrics, as well as more granular, detailed EJ analysis Specifically:

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- 1 • DAAO Witness Koeppel states "The Commission should require DTE to
- 2 analyze changes in demographics over time when assessing the equity
- 3 impacts of its proposed long-term investments."²⁹
- 4 • CEO Witness Kenworthy states "DTE should also consider how equity is
- 5 integrated into its operational practices."³⁰

6

7 **Q87. How does the Company respond to the Witnesses' requests?**

8 A87. The Company does not believe that a Commission order requiring additional EJ
9 analysis is needed at this time. Please refer to my revised direct testimony in Part
10 XI which describes how EJ is currently considered when proposing long-term
11 investments. The Company recognizes that EJ issues, data, tools, and analysis will
12 continue to evolve. For example, the State just launched MIEJScreen Version 1.0³¹.
13 The Company will continue to analyze the most current data and tools available
14 and looks forward to continuing to collaborate with stakeholders to gather their
15 input on the future analysis and development of plans for the 2025 DGP.

16

17 **Q88. DAAO Witness Koeppel states that "While the MIEJ Screen tool is a useful**
18 **starting point for identifying areas with high concentrations of low-income and**
19 **vulnerable populations, it does not provide a sufficiently granular or**
20 **differentiated picture of the specific needs, challenges, and opportunities**
21 **facing individual neighborhoods, households, or customer subgroups within**

²⁹ Koeppel DT, page 47, lines 6-8

³⁰ Kenworthy DT, page 21, line 15

³¹ State launches MiEJScreen Version 1.0 to illuminate environmental, health and socioeconomic conditions in communities, available at <https://www.michigan.gov/egle/newsroom/mi-environment/2024/08/06/state-launches-miejscreen-version-1>, accessed August 15, 2024

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1 **each tract.” (Pages 41, line 21-22 through page 42, lines 1-3). How do you**
2 **respond?**

3 A88. The Company is continuing to use the Draft MiEJScreen tool to identify vulnerable
4 customer areas. The Company believes this is the appropriate tool to use for
5 distribution analysis, because it was developed with extensive input from Michigan
6 stakeholders, including experts in the EJ community, is maintained by the State of
7 Michigan, and includes a breadth of socioeconomic and environmental factors in
8 its EJ impact scoring (Witness Kryscynski revised direct testimony, page 80, Figure
9 11). In addition, the census tract data is granular enough for DTE Electric to use in
10 reliability planning. More granular breakdowns of individual streets of
11 neighborhoods are not particularly useful because grid solutions typically need to
12 be addressed at the circuit or substation level.

13

14 **Q89. How do you respond to DAAO Witness Koepfel’s statement that “In DTE’s**
15 **current mode of equity analysis, these differences continue to be flattened by**
16 **a binary assessment of vulnerable vs. not vulnerable tracts.”³²?**

17 A89. While the Company does use the descriptors of “vulnerable” to describe customer
18 geographic areas with 80-100 MiEJscreen scores, and “non-vulnerable” to discuss
19 those with scores less than 80, the Company does in fact calculate and consider
20 smaller gradations. As an example, in response to the Commission’s direction in
21 Case No. U-21297 to conduct in depth EJ analysis, the Company (in the instant
22 case) sharpened the analysis into 5% gradients.

23

³² Koepfel DT, page 42, lines 16-17

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1 **Q90. Do you agree with DAAO Witness Koeppel’s statement that “...the CODI**
2 **areas nonetheless likely count towards Kryscynski’s binary bucketing of**
3 **“vulnerable” census tracts” (page 43, lines 7-9) to be accurate?**

4 A90. No, his statement is inaccurate and not supported by the analysis the Company
5 provided in this case. CODI projects are evaluated individually in the GPM, and EJ
6 scores are applied only if the project directly impacts the census tract. The EJ score
7 averages the collective census tract scores, weighted by customers impacted in each
8 tract.

9

10 **Q91. DAAO Witness Koeppel criticizes specific CODI investments supported by**
11 **Company Witness Deol as not improving service to vulnerable populations,**
12 **and further criticizes Witness Kryscynski based on a presumption that these**
13 **projects then “count” in what he perceives are binary bucketing of vulnerable**
14 **census tracts. (Koeppel, page 42, lines 16-17, and page 43, lines 6-10). How does**
15 **the Company respond?**

16 A91. In addition to my comments immediately above about the granularity of MiEJ
17 screening tool scoring and the evaluation of CODI projects, DAAO Koeppel seems
18 to misunderstand the Company’s use of EJ as one factor in addition to other factors
19 in evaluating projects and programs through GPM. The multiple factors including
20 reliability, safety, and EJ results in a balanced portfolio of investments that support
21 multiple grid objectives for all customers, including those who are the most
22 vulnerable. The diverse set of projects and programs go beyond the criticized
23 CODI conversions and include as examples like the 4.8kV Hardening program in
24 Detroit, to the replacement of at-risk equipment at Chestnut substation in Madison
25 Heights, to circuit conversions to support safety, reliability, and capacity in Pontiac.

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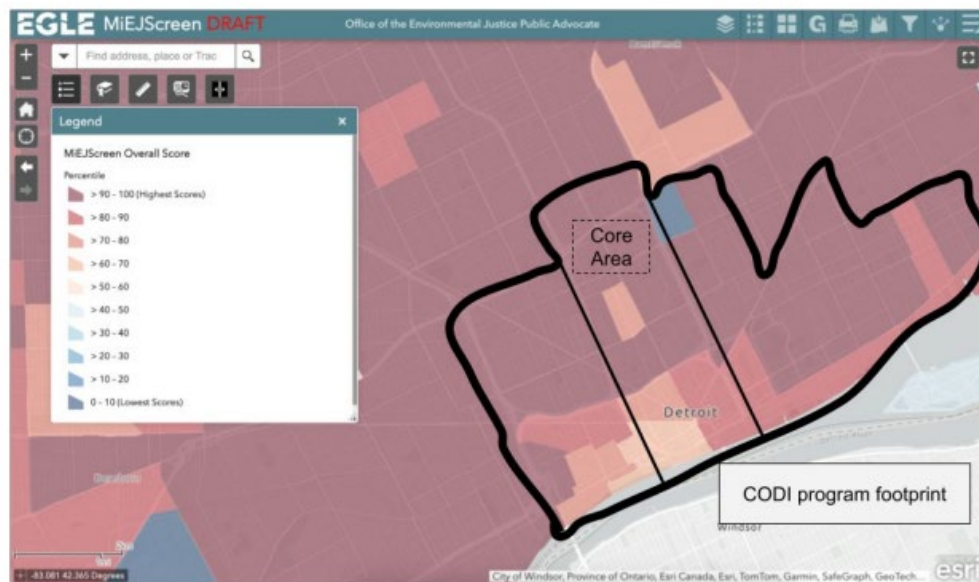
9

In addition, Witness Koeppel undercuts his own claim that CODI is not sufficiently EJ focused with a map in his testimony (Figure 1 on page 44), that shows that the vast majority of the area in the CODI has a an MIEJScreen Tool score of over 80 with well over half the area with a score over 90. I have included his figure in my testimony for easy reference as Figure 3.

Figure 3 MIEJScores of Downtown Detroit and Surrounding Areas

from Witness Koeppel's Testimony (page44)

Figure 1: MiEJScreen Grab, Economic Development and Load Growth Map⁵⁷



10

11 **Q92. DAAO Witness Koeppel states that table 14 on page 92 of your direct**
 12 **testimony “indicates a strong potential that population density is a significant**
 13 **factor in reliability performance.”³³ Do you agree?**

³³ Koeppel DT, p. 44, lines 8-9

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1 A92. No. There is no way to accurately draw this conclusion from the information
2 provided in Table 14. The table shows the distribution of residential customers in
3 each EJ gradation but does not provide enough information to make a determination
4 of relative population density. This is because the table, included here as Table 9
5 for easy reference, does not indicate the number of census tracks within each
6 grouping, and more importantly, does not include the square miles associated with
7 each grouping. Furthermore, density has additional complexity such as, within a
8 given area, whether the population is spread apart equally or clustered in one
9 location.

10

11

Table 9 Residential Customers by EJ Gradations

Census Tract EJ % Group	Number of Residential Customers	% of Residential Customers
0-5%	7,569	<1%
5-10%	39,705	2%
10-15%	62,143	3%
15-20%	43,497	2%
20-25%	59,888	3%
25-30%	88,033	4%
30-35%	100,487	5%
35-40%	99,318	5%
40-45%	102,680	5%
45-50%	114,416	6%
50-55%	120,730	6%
55-60%	135,206	7%
60-65%	124,240	6%
65-70%	126,463	6%
70-75%	100,278	5%
75-80%	146,161	7%
80-85%	127,270	6%
85-90%	162,145	8%
90-95%	143,144	7%
95-100%	114,874	6%
Unmapped/Unscored*	38,383	2%
Total Residential Customers	2,056,630	100%

12

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1 **Q93. GLREA Witness Rafson claimed that “According to the Center for Disease**
2 **Control [CDC], a 1% drop in socioeconomic status results in waiting 170**
3 **minutes longer on average to restore power.” (Page 5, Lines 8-9), with a**
4 **reference to an article in an online publication called “Governing”, by authors**
5 **Chuanyi Ji, Georgia Institute of Technology, and Scott C. Ganz, Georgetown**
6 **University. Do you have any concerns about his claim and conclusions with**
7 **respect to the applicability to DTE Electric’s vulnerable customers?**

8 A93. Yes. First, I’d like to clarify that the conclusion of the relationship between
9 socioeconomic status and power restoration time was the work of authors Ji and
10 Ganz, not the CDC. The CDC socioeconomic status data was simply used to
11 represent the populations as one factor in their analysis. The CDC has a database
12 similar to Michigan’s MiEJ Screening tool. Secondly, the article was in reference
13 to data for 15 million consumers in 588 U.S. counties between 2017-2020. DTE
14 Electric has chosen to use more recent data in its EJ analysis, using the MiEJ
15 screening tool to include multiple factors to define vulnerability, and most
16 importantly, data for the Company’s specific customers, not the broader US
17 population. Finally, the Company would note that the article referenced by Witness
18 Rafson went on to provide hypotheses for the longer restoration times, including
19 that the communities they referenced may be in predominantly older neighborhoods
20 where power infrastructure may require more significant repairs. This is consistent
21 with the testimony of Company Witnesses Deol and Elliott Andahazy when they
22 describe the need for Conversion and Hardening to support improved reliability for
23 the Company’s oldest 4.8kV infrastructure.

24

Line
No.

1 **Q94. DAAO Witness Jacob expresses concern about DTE Electric’s reliability**
2 **performance and investments related to EJ by stating that “DTE Energy has**
3 **not invested in grid and line updates equitably within low-income communities**
4 **and communities of color in metro Detroit.” (Page 3, Lines 22-23). Does the**
5 **Company agree with this characterization of past investment practices?**

6 A94. No. Witness Jacob provides absolutely no support in testimony to substantiate these
7 claims of inequitable investment. The Company, however, has provided evidence
8 to support that it has been investing heavily in EJ areas.

9
10 **Q95. How does the Company describe its grid investment from an EJ perspective?**

11 A95. The Company is maturing in its approach, including consideration of EJ as a factor
12 in prioritization of grid improvements. As described in my revised direct testimony,
13 the Company evaluated how its investment programs are reaching vulnerable
14 communities to improve reliability performance. For example, of the nearly half
15 billion dollars of investment in the 4.8kV Hardening program since 2018, 85% of
16 work performed under the Hardening program occurred in vulnerable communities.
17 Further details are included in my revised direct testimony (pages 93-101) and the
18 section 12.2 of the 2023 DGP (Exhibit A-23 Schedule M8).

19
20 **Q96. CEO Witness Tan provided an updated regression analysis with 2023**
21 **reliability data³⁴, are there concerns regarding the errors within the analysis?**

22 A96. Yes. The Company had one of its in-house data scientists, Dr. Joseph Naiman,
23 review Witness Tan’s testimony and attachments. Dr. Naiman holds a PhD in
24 Biostatistics from the University of Michigan, Ann Arbor. Dr. Naiman has

³⁴ Tan DT describes the updated analysis on pages 7-8

Line
No.

1 previously reviewed a similar analysis in the previous DTE Electric rate case U-
2 21297.

3

4 Dr. Naiman identified that Witness Tan's regression analysis results in the previous
5 case seen in his testimony page 11, table 1 (DTE 2021-2022 AW SAIDI Regression
6 Analysis, from Case No. U-21297) are based on a census tract level data by year.

7 The updated analysis in the instant case, which Witness Tan states is a
8 "improvement"³⁵ of the previous analysis, is based on city level within census tract

9 data for the year 2023 – see results in Witness Tan's testimony page 12, Table 2
10 (DTE 2023 AW SAIDI Regression Analysis). The reason for this change is that

11 Witness Tan, as identified by Dr. Naiman in his review, mistakenly used a data set
12 based on municipal census tracts. Because census tracts can contain several
13 municipalities, many census tracts were included multiple times in the data set³⁶.

14 Essentially, the updated regression analysis is fundamentally different than the
15 previous analysis.

16

17 **Q97. Are there concerns regarding CEO Witness Tan's conclusions between the**
18 **updated regression analysis and the previous regression analysis?**

19 A97. Yes. With the updated regression analysis based on city level within census tract
20 information versus census tract information, the Company has concerns about the
21 validity of the comparison between the previous rate case and the instant case
22 regression analyses. Witness Tan assumes that within a census tract the reliability
23 metric is as different as if it was in a completely different census tract miles away
24 (this is a violation of the independence assumption of the type of regression Witness

³⁵ Tan DT, p. 7, lines 20-21

³⁶ Note that the number of data points in Table 1 is lower (~2,900) than the data points in Table 2 (~4,400)

Line
No.

1 Tan produced). Dr. Naiman ran the regression analysis accounting for the
2 relationship within the census tract and some of the results were no longer
3 statistically different. Furthermore, had Witness Tan run the regression using the
4 same approach as he had for the 2022 data, the level of statistical significance
5 decreases in some variables.

6

7 **Q98. What is the Company’s proposed next step regarding EJ regression analysis?**

8 A98. Separately, the Company is actively working on EJ regression analysis with
9 Witness Tan and Staff that will be included in the 2025 DGP. The Company is
10 looking forward to continuing collaborating with stakeholders on this effort to
11 create a robust regression that all stakeholders, including the Company, can
12 support.

13

14 **Rebuttal Issue 12: Community Coordination**

15

16 **Q99. What did the Commission order in Case No. U-21297 with regard to**
17 **Community Coordination?**

18 A99. The Commission stated that “DTE Electric should coordinate construction
19 activities with local units of government”³⁷. In response, the Commission ordered:

20

21 “Therefore, in its next rate case, DTE Electric shall include a demonstration of its
22 efforts to improve communication and coordination with local governments
23 regarding construction activities.”

24

³⁷ MPSC U-21297 order dated December 1, 2023, page 375

Line
No.

1 **Q100. How has DTE Electric complied with this requirement?**

2 A100. In revised direct testimony, Witness Kryscynski noted on page 102, lines 6 through
3 22, that the Company frequently, through a variety of methods, communicates and
4 coordinates with municipalities to discuss the details of projects located within
5 communities, benefits, and collaboration opportunities. The Company focuses on
6 removing potential construction conflicts, prior to permits being sought, and
7 provides periodic updates and meetings as requested by individual municipalities.

8

9 Additionally, the Company is focused on improving communication and
10 coordination with municipalities and county road commissions including
11 identifying preferred methods of receive planning and construction updates.

12

13 **Q101. In this rate case, what concerns were expressed in testimony regarding the**
14 **coordination of DTE Electric distribution construction work with other**
15 **utilities and municipalities?**

16 A101. In testimony, MAUI Witness Bunch says that he believes the Company failed to
17 meet the Commission's coordination directive. He states that the Company did not
18 provide "data, a more detailed description of policies and practices, and examples"
19 to show its coordination improvements, page 78, line 17.

20

21 Also, Ann Arbor Witness Stults states "the purpose of the Commission's directive
22 was for DTE to include local governments in the planning and coordination of
23 projects in their early stages in an effort to identify cost savings and efficiencies,
24 not merely to communicate DTE Electric's pre-planned projects to communities",
25 page 23 lines 9-12.

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1

2 **Q102. Can you provide examples of the types of community coordination and**
3 **outreach that the Company already performs, and as was requested by MAUI**
4 **Witness Bunch?**

5 A102. Yes. The Company routinely engages with municipalities, municipal organizations,
6 and others through a variety of methods depending on municipal needs and
7 preferences. Examples include:

- 8 • Permits and Easements Coordination – the Company works with over 400³⁸
9 municipalities in its electric service area for permits and easements,
10 primarily for its strategic investment activities.
- 11 • Regional Affairs Managers – the Company provides each community a
12 regional affairs manager that serves as the point person between the
13 Company and the community. The Regional Affairs managers are typically
14 well known by community officials and are usually the first point of contact
15 for a broad variety of topics, including project coordination.
- 16 • Monthly Community Lighting Meetings – held in areas that the Company
17 provides lighting services
- 18 • Reliability and Resiliency Updates – Periodic updates tailored to individual
19 community needs
- 20 • Project Coordination Meetings - with both DTE Electric and DTE Gas
- 21 • Presentations to City Council, Historic Commission and Neighborhood
22 Associations – conducted as needed
- 23 • Community and Project Open Houses – conducted both proactively and as
24 requested

³⁸ Utility Provider Search, available at <https://utilitysearch.apps.lara.state.mi.us/search>, accessed August 6, 2024

Line
No.

- 1 • General Community Outreach – conducted through local churches and
- 2 school district
- 3 • Direct Customer Communication – through Blog newsletter, Nextdoor,
- 4 letters, door hangers, emails, etc.
- 5

6 **Q103. Has the Company continued its efforts to improve community coordination**
7 **since after the Commission Order in U-21297 and after the filing the instant**
8 **case?**

9 A103. Yes. Prior to this summer, the Company made electric and tree trimming maps,
10 available to communities (as well as the public), titled “DTE Electric Reliability
11 Improvements Map”. The old map can be accessed at through this link:

12

13 [https://dte.maps.arcgis.com/apps/webappviewer/index.html](https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e)
14 [?id=5d9dc2eb124445618959ce788086e00e](https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e)

15

16 Relaunched earlier this summer as the Power Improvements Map (PIM), the
17 updated tool provides localized information about current, planned and past
18 infrastructure repairs and upgrades. This means that anyone in the Company’s
19 electric service territory can enter a county, city, zip code or personal address into
20 the map and see what grid improvement work is currently in progress, planned over
21 the next two years or completed over the past three years. The map provides a
22 localized view of reliability performance for a given area after the end of each
23 calendar year, beginning with 2023. By using the PIM, all stakeholders including
24 elected and appointed officials, community leaders, regulatory officials,
25 environmental justice advocates, customers, along with the media and others, can

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1 see the work the Company is doing and in a format that is accessible and
2 transparent. The Power Improvements Map is accessible through the Company's
3 website, and can also be found directly at:

4 <https://dteenergy.com/powermap>
5

6 **Q104. Are there other efforts underway to help address AA Witness Stults request**
7 **to improve early-stage project coordination?**

8 A104. Yes. In the third quarter of 2023, a new permitting team was created within the
9 Project Management Office³⁹. The new team has six permit specialists, as well as
10 an Michigan Department of Transportation (MDOT) Coordinator, and supervisor.
11 The team is focused on building permitting expertise, building external
12 relationships, and streamlining processes. Since initiation, the permit specialists
13 have been creating a playbook for each municipality that includes the specific
14 permit requirements, timelines, process, and local contacts. The permit team
15 actively coordinates work with Regional Affairs Managers to ensure alignment,
16 resolve open issues, and coordinate on joint construction opportunities where they
17 exist.
18

19 **Q105. Are there existing processes to coordinate at a county and regional level?**

20 A105. Yes. Our regional affairs managers continue to participate and present in meetings
21 with the following groups:

- 22 • Federal-Aid Committees (FAC) are comprised of representatives of local
23 governments, transit agencies and MDOT. FAC focuses on evaluating data

³⁹ PMO was discussed in Question 12 of Kryscynski revised direct testimony

Line
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1 and recommending projects that meet regional transportation goals⁴⁰. There
2 are different FAC for the City of Detroit, Livingston County, Macomb
3 County, Oakland County, St. Clair County, Washtenaw County and Wayne
4 County.

5 • Southeast Michigan Council of Governments or SEMCOG is a regional
6 planning partnership of governmental units serving 4.8 million people in the
7 seven-county region of Southeast Michigan striving to enhance the region's
8 quality of life.

9 • Michigan Townships Association (MTA) provides a unified voice for
10 Michigan townships on both the state and federal levels and influences
11 legislation, policy and regulations by representing townships before the
12 Legislature, the executive office and state agencies.⁴¹

13 • Michigan Municipal League (MML) supports innovative work through
14 partnerships, grants and programming that creatively and intentionally
15 bring people together and build equitable community wealth.⁴²

16

17 **Q106. Is there an existing statewide process to coordinate infrastructure projects?**

18 A106. Yes, there are several ways the Company coordinates at a statewide level. First, the
19 Michigan Infrastructure Council (MIC) was formed under Public Act 323 of 2018.
20 Their mission “is to cultivate partnerships that strengthen Michigan's Infrastructure
21 to provide the foundation for public and environmental health, economic

⁴⁰ Federal-Aid Committees, available at <https://www.semcog.org/federal-aid-committees#5304578-city-of-detroit>, accessed August 7, 2024

⁴¹ MTA on the Issues, available at <https://michigantownships.org/advocacy/mta-issues/>, accessed on August 7, 2024

⁴² MML Foundation, available at <https://mmlfoundation.org/>, accessed on August 7, 2024

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1 prosperity, and quality of life”⁴³. The MIC is actively working to coordinate and
2 collaborate with entities throughout Michigan. The MIC Project Portal (MiDIG)⁴⁴
3 is “intended to assist authorized infrastructure asset owners and managers, private
4 utilities, and state agencies across the State of Michigan with cross asset
5 collaboration and coordination”. DTE Electric is collaborating on the user
6 agreement with the MIC to share electric and gas capital construction projects on
7 the statewide portal.

8
9 Second, DTE Electric meets monthly with the Michigan Infrastructure Office
10 (MIO) to discuss high level coordination, primarily focused on grant applications
11 available through the Bipartisan Infrastructure Law (BIL). The MIO was formed
12 to ensure resources sent to Michigan through the BIL are used efficiently and
13 effectively.⁴⁵

14
15 Third, the Company collaborates with MDOT on larger infrastructure projects. One
16 example included in the instant case is the I-375 Reconnecting Communities
17 Project, replacing the current below-grade freeway corridor with a grade-level
18 boulevard. Two bridge examples are the 4.8kV CC: Pinegrove Substation
19 Relocation and Conversion project, which requires the relocation of Pinegrove
20 Substation to accommodate the expansion of the Bluewater Bridge, and the Gordie
21 Howe International Bridge, which required the relocation of seven and removal of
22 five subtransmission lines.

⁴³ About the Michigan Infrastructure Council, available at <https://www.michigan.gov/mic/about>, accessed on August 5, 2024.

⁴⁴ MIC Project Portal, available at <https://www.michigan.gov/mic/project-portal>, accessed on August 5, 2024.

⁴⁵ Michigan Infrastructure Office, available at <https://www.michigan.gov/whitmer/issues/michigan-infrastructure-office>, accessed on August 7, 2024

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1 The Company believes its coordination efforts at the state level are essential to
2 communicate our projects in a clear and consistent manner, not only for the
3 communities in our service area, but for collaboration and coordination with state
4 agencies and other utilities.

5

6 **Q107. Does the Company believe there is a strong benefit to working with local**
7 **governments and communities throughout the project planning and**
8 **construction process?**

9 A107. Yes. Coordination not only allows both the Company and the municipalities to be
10 more thoughtful and prudent with our respective capital investments, but it also
11 improves the overall project timeline and productivity by identifying important
12 obstacles early in the planning phases.

13

14 **Q108. Beyond the efforts described above, can coordination be further improved in**
15 **the future?**

16 A108. Yes, with the increase of Company and Municipal construction projects in recent
17 years, there are always opportunities to improve communication and coordination.
18 The Company is willing to explore improving coordination with all stakeholders
19 and would propose a series of engagements focused on identifying opportunities to
20 further enhance existing processes.

21

22 **Q109. What future disallowance does MAUI Witness Bunch recommend that the**
23 **Commission adopt?**

24 A109. On page 84, starting at line 20, Witness Bunch suggests 10% disallowance on
25 electric infrastructure investments with excavation work in the public right of way

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1 or public easements, unless the Company can prove it has made reasonable attempts
2 to coordinate work with such projects.

3

4 **Q110. Does the Company agree with MAUI Witness Bunch’s recommendation that**
5 **future project costs may be excluded from recovery if there is failure to**
6 **coordinate work?**

7 A110. No. While DTE Electric believes that work coordination is preferable, it does not
8 agree that costs should be excluded from recovery if work coordination does not
9 occur. There are many reasons why it may not be possible to coordinate work.
10 First, the Company’s investment work may need to be done sequentially and may
11 not be able to be aligned perfectly with the municipality. Second, there may be
12 regulatory requirements that do not allow for timeline adjustments. Lastly, there
13 may be times due to unforeseen circumstances, new business work as an example,
14 a project needs to be built on a short timeline, which may not allow much time for
15 coordination.

16

17 Additionally, this standard would be difficult to implement and evaluate as opinions
18 regarding what constitutes a “reasonable attempt” could vary substantially. For
19 these reasons, the Company recommends that the Commission reject this proposal.

20

21 **Q111. Are there other recommendations from MAUI Witness Bunch, or Ann Arbor**
22 **Witness Stewart?**

23 A111. Yes. Below is a summary of their recommendations and rebuttal points

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1

Table 10 Municipal Coordination Recommendations

2

Witness	Testimony	Rebuttal Point
Bunch	“In most cases, the requirement regarding local governments could be met by reference to publicly-available CIPs with very little effort.” Page 85 lines 4-5 Furthermore, as stated by Witness Bunch, “In most cases, local governments make them readily available through their websites. If a CIP were not available on a website, a utility could easily get a copy by contacting the local government – no FOIA request is needed.” on page 83 lines 10-12.	Witness Bunch’s testimony implies a central location for all municipal plans which does not exist. Alternatively, the Company has made its construction efforts publicly available on the Power Improvements Map for all 415 municipalities in its service area.
Bunch	“The Commission should require DTE to demonstrate that it prioritizes locations of infrastructure undergrounding and underground maintenance projects, in part, by identifying local-government infrastructure projects that require excavation with which the DTE projects could be co-located and -scheduled.” Page 85 lines 6-9	DTE Electric prioritizes the location of projects and maintenance to support providing electricity to our customers first. DTE Electric strives to proactively work with municipalities to collaborate on co-location and scheduling, while still providing service to our customers.
Stewart	“Often, the way the City staff receives notice of a planned DTE project is through the Company’s application for a right of way permit. Notice at this late stage of a project is not conducive to meaningful coordination or collaboration.” Page 6 lines 1-3	The Company is actively improving its coordination efforts and has made its construction efforts publicly available on the Power Improvements Map for all 415 municipalities in our service area.

3

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1 **Rebuttal Issue 13: Distribution Pilots and Recommendation**

2

3 **Q112. Beyond the pilots proposed by CEO Witness Volkmann which have been**
4 **discussed above, have other witnesses proposed additional distribution pilots?**

5 A112. Yes, two additional pilots proposed were proposed in testimony:

6 1. "...an underground geothermal network be evaluated as a pilot project for
7 at least one resilience microgrid in Highland Park, with community
8 participation as to its location, possibly Parker Village" was recommended
9 by DAAO Witness Makhijani on page 59, lines 15-17

10 2. "The Commission should direct the Company, in its next rate case or
11 demand response case, to propose a pilot of geo-targeted incentives for
12 customer-owned distributed energy systems (including batteries)." was
13 recommended by GLREA Witness Richter, page 54, lines 11-13.

14

15 **Q113. What is the Company's current pilot status and process?**

16 A113. The Company is committed to completing the NWA pilots underway and
17 communicating lessons learned and results in order to inform discussions on how
18 to scale the piloted technologies. As noted in section 9.1.2 of the Distribution Grid
19 Plan (Exhibit A-12, Schedule M8), the Company has already incorporated NWA
20 options into its grid planning. Engineering has developed a screening process to
21 determine which load relief projects might be good candidates for a NWA, and then
22 if the project is a good candidate, works with planning engineers to determine the
23 appropriate grid solution.

24

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1 Although the Company doesn't have current plans to expand the set of NWA pilots,
2 it will continue to evaluate promising new technologies, and use the Commission's
3 recently developed expedited pilot process, February 23, 2023 order in Case No.
4 U-20898, for consideration of any future potential pilots. The expedited pilot
5 process does have provisions for stakeholder engagement.

6

7 **Q114. Were there other distribution recommendations?**

8 A114. Yes. GLREA Witness Rafson recommended "The Commission should specifically
9 allow nanogrids and microgrids" on page 13, line 11 of their testimony.

10

11 **Q115. Does the Company have any concerns about this recommendation?**

12 A115. Yes. This proposal impacts tariffs and other operational and significant safety
13 issues. If the Commission decides there is merit in pursuing this proposal further,
14 it should be addressed in separate interconnection rules forum.

15

16 **Q116. Does this conclude your rebuttal testimony?**

17 A116. Yes, it does.

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.)

TIMOTHY J. LEPCZYK

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF TIMOTHY J. LEPCZYK

Line
No.

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

2 A1. My name is Timothy J. Lepczyk (he/him/his). My business address is DTE Energy
3 Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE
4 Energy Corporate Services, LLC as Assistant Treasurer and Director of Corporate
5 Finance, Insurance and Development.

6
7 **Q2. Are you the same Timothy J. Lepczyk who previously offered testimony in this**
8 **proceeding?**

9 A2. Yes, I am.

10

11 **Q3. What is the purpose of your rebuttal testimony?**

12 A3. The purpose of my testimony is to rebut the arguments made by Michigan Public
13 Service Commission Staff (Staff) Witness Joseph E. Ufolla and Witness Shannon
14 Rueckert, Attorney General (AG) Witness Sebastian Coppola, Association of
15 Businesses Advocating Tariff Equity (ABATE) Witness Christopher C. Walters,
16 and Attorney General (AG), Michigan Environmental Council (MEC), and Natural
17 Resources Defense Council (NRDC), collectively referred to as “AG-MN” Witness
18 Paul Alvarez.

19

20 The absence of a discussion of other matters in my rebuttal testimony should not
21 be taken as an indication that I agree with other aspects of any Staff or intervenor
22 testimony.

23

24 **Q4. Are you sponsoring any rebuttal exhibits?**

25 A4. I am sponsoring the following rebuttal exhibit:

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<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-45	JJ1	Updated Projected Cost of Long-term Debt

3

4 **Q5. Was this exhibit prepared by you or under your direction?**

5 A5. Yes, it was.

6

7 **Capital Structure**

8 **Q6. Do you agree with ABATE Witness Walters' assertion on page 25 that DTE**
9 **Electric proposes an equity ratio of 53.5%?**

10 A6. No. Consistent with the relief requested in DTE Electric's Application in this rate
11 case, pages TJL-8 Line 15 through TJL-9 Line 20 of my direct testimony, proposed
12 an equity ratio of 50%. We could not find evidence of the Company requesting a
13 proposed equity ratio of 53.5% and assume this is an error in Mr. Walters'
14 testimony. However, contrary to Witness Walters' assertion that DTE Electric's
15 proposed equity ratio significantly exceeds the equity ratio for the proxy group,
16 Exhibit A-14, Schedule D1.1, shows that the average equity ratio for DTE Electric's
17 peers is approximately 52%. DTE Electric believes its requested 50% equity ratio
18 is reasonable and lower than the average equity ratio of its peers.

19

20 **Development of Cost Rates**

21 **Q7. Do you agree with Staff Witness Ufolla's recommendation on page 22 of his**
22 **direct testimony for a Long-Term Debt rate of 4.21%?**

23 A7. No. Based upon an updated rate curve as of August 6, 2024, the Company now
24 calculates a Long-Term Debt issuance rate of 5.53% for 2025 (as compared against
25 a long-term debt rate for the projected 2025 issuance of 5.62% in my original

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1 testimony and 5.33% as calculated by Witness Ufolla), based on an average
2 projected 30-year treasury rate of 4.05% plus a 148 bps spread. With these updated
3 projected 2025 issuances and actual 2024 issuances, the weighted average long-
4 term debt cost as of December 31, 2025, approximates the projected 4.24%
5 calculated in my original testimony and shown on Exhibit A-45 Schedule JJ1.

6

7 **Q8. Do you agree with Staff Witness Ufolla's recommendation on page 22 of his**
8 **direct testimony for a Short-Term Debt rate of 4.96%?**

9 A8. No. Given the potential for "higher for longer" interest rates, as well as the
10 consistent overly-optimistic forecasts regarding the proximity of Fed rate cuts, we
11 believe the current short-term cost of debt is a more appropriate metric than the
12 market's forecast rate. The actual average borrowing rate for DTE Electric in July
13 2024 was 5.48% (this figure includes DTE Electric's actual interest rate spread).
14 The cost of credit facility fees adds an incremental 0.25% for a total short-term debt
15 rate of 5.73%. Due to the continued market volatility, the Company feels it is
16 reasonable and prudent to use the July 2024 short-term cost of debt rate of 5.73%.

17

18 **Securitization**

19 **Q9. Do you agree with the rate used by Staff Witness Rueckert and AG Witness**
20 **Coppola to calculate the Return on Tree Trim Regulatory Asset?**

21 A9. No. The Company maintains its position that any future tree trim surge
22 expenditures should be financed through permanent capital. In past cases (e.g.,
23 Case No. U-21015), the Commission directed DTE Electric to retire existing long-
24 term debt and equity with the proceeds from the sale of the securitization property.
25 The Company feels that it is therefore consistent that the return associated with the

Line
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1 surge regulatory asset be commensurate with the capital that will ultimately be
2 retired with the proceeds of that securitization.

3

4 **Q10. Do you agree with AG-MN Witness Alvarez's recommendation on Page 41,**
5 **Lines 19 – 20 of his direct testimony, that the Commission reject the**
6 **Company's request to earn a return for shareholders on the Tree Trim Surge**
7 **Regulatory Asset?**

8 A10. No. As stated in Answer 9, the Company maintains its position that its pre-tax
9 weighted average cost of permanent capital should apply to tree trim surge balances
10 prior to securitization, as – in past cases – the Commission has directed the
11 Company to retire long-term debt and equity with the proceeds of securitization.

12

13 **Q11. Does this complete your rebuttal testimony?**

14 A11. 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-21534

REBUTTAL TESTIMONY

OF

HABEEB J. MAROUN

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF HABEEB J. MAROUN

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Habeeb J. Maroun (he/him/his). My business address is One Energy
4 Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate
5 Services, LLC, a subsidiary of DTE Energy Company as a Regulatory Strategy
6 Consultant, Regulatory Economics.

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company (DTE Electric or Company)?**

10 A2. Yes.

11

12 **Q3. Are you sponsoring any rebuttal exhibits in this proceeding?**

13 A3. Yes. I am sponsoring the following two exhibits:

14 1) U-21534 Exhibit A-38 Schedule CC1 System Demand Tests

15 2) U-21534 Exhibit A-38 Schedule CC2 SRM Capacity Charge Comparison

16

17 **Purpose of Testimony**

18 **Q4. What is the purpose of your rebuttal testimony?**

19 A4. The purpose of my testimony is to respond to intervenor direct testimony,
20 specifically addressing the topics listed below. The absence of rebuttal on any
21 given matter does not constitute agreement by the Company.

22 1) Respond to Michigan Environmental Council, Natural Resources Defense
23 Council, Sierra Club, and Citizens Utility Board of Michigan (MNSC)
24 Witnesses Jester's and Denzler's proposal to replace 4 Coincident Peak (CP) in
25 the Cost-of-Service Study (COSS);

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- 1 2) Respond to MNSC Witnesses Jester's and Woolley's proposal to analyze
- 2 seasonality and distribution costs in the next rate case;
- 3 3) Respond to Energy Michigan Zakem's proposal to alter the State Reliability
- 4 Mechanism (SRM) capacity charge calculation;
- 5 4) Respond to MPSC Staff's (Staff) proposed change to the allocation of
- 6 purchased power capacity in the COSS as sponsored by Staff Witness Pung;
- 7 5) Respond to errors in Staff's as-filed COSS model.

8

9 **Recommendations**

10 **Q5. Please summarize your conclusions and recommendations to the Commission.**

11 A5. My conclusions and recommendations are outlined below:

12

13 **MNSC Proposals**

- 14 1) The continued application of the Commission-approved 4 CP method for the
- 15 production plant allocator is appropriate. The updated system demand tests
- 16 confirm DTE continues to be a summer peaking utility supporting the use of
- 17 the 4 CP method. Witnesses Jester and Denzler have not shown that their
- 18 proposals, argued based on changes to the MISO-construct, more appropriately
- 19 reflect the cost drivers for the \$10 billion of production plant embedded costs
- 20 in the Company's revenue requirement.

21

22 Additionally, the current 4 CP method for the allocation of capacity revenue
23 requirement, as detailed in Exhibit A-16 Schedule F1.5 (capacity charge
24 revenue requirement by class), should remain as is. Any changes should only

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1 be considered if the Commission decides to alter the existing 4 CP method for
2 apportioning production plant costs.

3 2) The suggestion by Witness Jester for the Company to perform an analysis on
4 seasonality and distribution costs for the upcoming rate case is deemed
5 insufficiently detailed. Additionally, the Company opposes the consideration
6 of alternatives to the Commission-approved class NCP allocators for
7 apportioning distribution plant costs by voltage level, particularly based on
8 summer peak demands. Company Witness Deol rebuts Witness Woolly's
9 assertions. Finally, the increased complexity that Witnesses Jester's and
10 Woolly's proposed analysis would add to the COSS in terms of time and
11 resources required for completion, in addition to the absence of clearly defined
12 benefits, lead to the conclusion that this recommendation should not be
13 considered.

14

15 Energy Michigan Proposal

16 3) If purchased power energy were reclassified as capacity costs as asserted by
17 Witness Burgdorf in his rebuttal testimony, this reclassification would not alter
18 the SRM capacity charge from the Company's as-filed amount.

19

20 MPSC Staff Proposal

21 4) The Company proposes to continue allocating purchased power capacity using
22 4 CP 100-0-0 demand less R10 (allocator 251) and purchased power energy
23 using 0-0-100 energy less R10 (allocator 111). Should the Commission agree
24 with Staff's proposal to align the allocation of purchased power capacity and
25 with the current allocator used for production plant using allocator 255 (4 CP

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1 75-0-25), it would also be prudent to ensure consistency in the corresponding
2 allocation of purchased power energy and fuel costs. Currently, fuel costs are
3 allocated using allocator 192 (12 CP 10-0-90).

4 5) Errors pertaining to the following items should be corrected in the COSS model
5 corresponding to the final order:

6 a. D13 Incremental Distribution Revenues: update amount by performing
7 a single iteration of COSS and rate design prior to calculation of final
8 rates;

9 b. Low Income and Senior Discounts: update COSS model to match
10 approved amounts.

11

12 **MNSC Proposal to Replace 4 Coincident Peak (CP) in the COSS**

13 **Q6. Does MNSC Witness Jester take issue with the currently approved production**
14 **plant cost allocator, 4 CP 75-0-25?**

15 A6. Yes. In his direct testimony, MNSC Witness Jester does not suggest any
16 modifications to the 75-0-25 segment of the production plant allocation formula
17 (allocator 255). His critique is directed exclusively at the 4 Coincident Peak (CP)
18 measurement. On page 13, lines 10 to 11, Jester states, “I am focusing on only one
19 of the methods about which I disagree with DTE Electric’s proposal, the use of 4CP
20 to allocated Production Plant.” He then proceeds to outline two alternative
21 approaches to the 4 CP method, details of which will be elaborated upon later in
22 this rebuttal testimony.

23

24 **Q7. Has the 4 CP allocator been previously approved by the Commission?**

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1 A7. Yes. The MPSC Commission initially approved the inclusion of the 4 CP
2 measurement within the production plant allocation in Case No. U-17689. This
3 methodology has since received consistent approval across the Company's
4 subsequent seven electric rate cases, specifically Case Nos. U-17767, 18014,
5 18255, 20162, 20561, 20836, and 21297.

6

7 **Q8. Why does Witness Jester disagree with the applicability of the 4 CP allocator?**

8 A8. In his direct testimony, Jester asserts that the DTE Electric production plant
9 requirements are not directly determined by customer demand. Based on his view,
10 this is due to potential fulfillment of power by other participants within MISO.
11 Furthermore, he suggests that during non-summer seasons with capacity
12 constraints, there may be a need for additional capacity resources to meet demand.
13 The selected excerpts underscore the key points of Jester's testimony.

14

15 "The power consumed by DTE Electric's customers will often be provided, at
16 least in part, by resources owned by other MISO market participants.
17 Consequently, DTE Electric's Production Plant requirements are not directly
18 determined by the demand from its own customers." (page 14 lines 18 to 21)

19

20 He further explains:

21

22 "With the combination of both seasonal reserve margins and seasonal
23 accreditation, it is entirely possible that customer demand in some season will
24 drive a need for additional Production Plant resources even though demand in
25 that season is distinctly lower than in the 4CP summer that DTE Electric has

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1 traditionally used. The Commission should conclude from MISO's seasonal
2 Resource Adequacy construct that Production Plant cost causation can no
3 longer be based solely on class contribution to peak nominal loads but instead
4 must be rooted in the seasonal performance of those resources." (page 17 lines
5 7 to 13)

6

7 Finally, he argues:

8

9 "The utilization of DTE Electric's Production Plant portfolio is distinctly lower
10 in Winter (71.9%) but varies only a little amongst the other seasons (between
11 96.5% and 98.4%). This pattern of utilization of DTE Electric's Production
12 Plant portfolio does not support the use of the 4 CP metric." (page 18, lines 2
13 to 5)

14

15 **Q9. What is your response to these arguments?**

16 A9. The 4 CP measurement was first sanctioned by the MPSC Commission in their
17 order dated June 15, 2015 for Case No. U-17689. This approval was grounded on
18 the four system demand tests presented by DTE Electric Witness Martin L. Heiser.
19 The Order in that case did not consider the MISO resource adequacy construct,
20 which was not factored into the decision-making process regarding the adoption of
21 the 4 CP approach. Consequently, the ongoing modifications to MISO's resource
22 adequacy approach are irrelevant and should not influence the decision to continue
23 with the 4 CP methodology in the instant case. Witness Jester has not explained,
24 regardless of the specifics of MISO's resource adequacy framework, why it is
25 appropriate to change the 4 CP production plant allocation approach to one

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1 premised on MISO considerations when, as I describe above, the Commission has
2 consistently used a different method for the last nine years.

3

4 **Q10. Can you summarize the Commission's determination in Case No. U-17689 that**
5 **the demand portion of production plant costs should be allocated using 4 CP?**

6 A10. The Commission conducted an evaluation of cost allocation methods in DTE
7 Electric's Case No. U-17689. The pivotal findings of the Commission, as stated on
8 page 20 of its June 15, 2015 order, pertain to the allocation of costs related to
9 production plant. The key conclusions of the Commission in the order with respect
10 to the allocation of production plant are provided below:

11

12 *The Commission agrees with DTE Electric, the Staff, and*
13 *ABATE, that a change from a 12CP to a 4CP demand allocator*
14 *is fully supported by the evidence presented in this proceeding.*
15 *Martin L. Heiser, Consultant, Regulatory Economics for DTE*
16 *Energy Corporate Services, LLC, explained that the company*
17 *applied four system demand tests that have been used by the*
18 *Federal Energy Regulatory Commission to determine the*
19 *appropriate demand portion of the allocator. The results of these*
20 *tests are consistent with the results for other utilities for which*
21 *FERC has authorized a 4CP allocator. See, 2 Tr 234-236;*
22 *Exhibit A-14. The Commission therefore rejects the ALJ's*
23 *recommendation to retain the 12CP demand allocator.*

24 Moreover, Commissioner White stated in his opinion on page 41 of the order,
25 "Based on the evidentiary record, I do agree with the shift to 4 CP from the
26 previously authorized 12 CP method. In that respect, I agree that DTE Electric is a
27 summer peaking company."

28

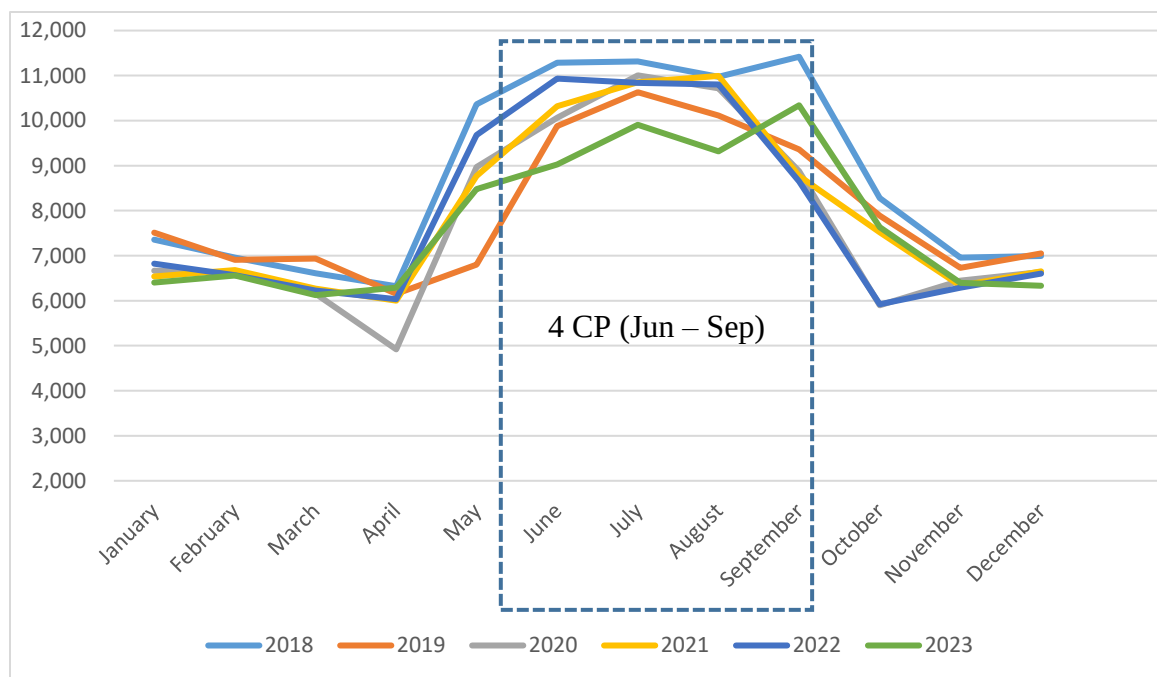
29 **Q11. Have you updated the four system demand tests utilized by Witness Heiser in**
30 **Case No. U-17689 to determine whether 4 CP is still appropriate?**

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1 A11. Yes. The tests have been updated as illustrated in Exhibit A-38 Schedule CC1 of
2 this rebuttal testimony, incorporating data from the most recent six-year period,
3 spanning from 2018 to 2023. This update reflects the monthly system peaks as
4 reported in DTE's MPSC P-521 reports on page 401b. Additionally, Figure 1
5 below offers a graphical representation of the monthly system peaks employed in
6 the updated tests.

8 **Figure 1 : DTE Electric Monthly System Peak Demands (MW)**

9 **2018 to 2023 (MPSC P-521, pg. 401.b)**



10

11 **Q12. What are the results of the updated tests shown in Exhibit A-38 Schedule CC1?**

12 A12. For test 1, where large differences between the annual peak and the average peak
13 lends support for using something other than 12 CP, DTE Electric's 4 CP ratio was
14 31% (previously 30%), near the upper bound of 31% for the four out of six cases

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1 where a method other than 12CP was allowed in the Guide¹. For test 2 examining
2 the lowest monthly peak as a percentage of annual peak, where higher percentages
3 indicate greater support for 12 CP, DTE's six year average was 54% (previously
4 55%), consistent with the range of results for the 6 out of 14 cases where a method
5 other than 12 CP was allowed in the Guide¹. The 8 out of 14 cases where the 12
6 CP method was allowed had percentages in excess of 70%. For test 3, none of DTE
7 Electric's monthly peaks occurring in the off-peak months exceeded the average
8 monthly peaks within the four peak months of June through September (consistent
9 with prior findings). For test 4, the six year average of the 12 peaks as a percentage
10 of the single high peak was 74% (previously 72%), below the minimum value of
11 81% exhibited by the 5 out of 8 cases where the 12 CP method was allowed.

12

13 **Q13. What is your conclusion based on these results?**

14 A13. The updated results, as detailed previously and illustrated in Exhibit A-38 Schedule
15 CC1, conclusively indicate that the 4 CP method remains the appropriate metric for
16 assessing the demand component of the production plant's cost allocation.
17 Consequently, the current method is validated, and no modifications are necessary.

18

19 **Q14. Can you describe the two options that Jester proposes to replace 4 CP?**

20 A14. Jester presents two options to replace the 4 CP method in his direct testimony,
21 which I have summarized below.

22

¹ A Guide to FERC Electric Utility Ratemaking (Guide), by Michael E. Small, Wright & Talisman, P.C.,
©1989 by Atlantic Information Services Inc.

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1 *Option 1 (page 18, lines 10 to 11): “The first option is to use 9CP, averaging the*
2 *customer class contributions to peak load in each of the months in Spring, Summer,*
3 *and Fall (March through November).”*

4

5 *Option 2 (page 19, lines 1 to 23): this option is referred to as the Weighted Seasonal*
6 *Capacity Increment (WSCI) by Witnesses Jester and Denzler. The following are a*
7 *summarized list of steps to calculate this option based on Witness Jester’s*
8 *testimony:*

- 9 ○ Allocate 71.9% of measurement using winter utilization and 12 CP
- 10 ○ Allocate 24.6% of measurement (96.5% spring utilization less 71.9%
- 11 winter utilization) using 9 CP covering spring, summer, and fall
- 12 ○ Allocate 1.6% of measurement (98.2% fall utilization less 96.2% spring
- 13 utilization) using 6 CP covering summer and fall
- 14 ○ The remaining 1.8% of the measurement is allocated based on 3 CP
- 15 covering summer

16

17 This proposal is effectively a blended weighting of 12 CP (71.9 percent) and 9 CP

18 24.6 percent), which comprise over 96 percent of the demand measurement.

19

20 **Q15. What is your opinion of Jester’s option 1 (9 CP)?**

21 A15. The Commission has already established that the demand component of the

22 production plant cost allocator is accurately represented by 4 CP. This was further

23 corroborated by the updated system demand tests presented in Exhibit A-38

24 Schedule CC1, which affirmed the ongoing application of 4 CP as a valid method.

25

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1 Interestingly, option 1 lacks a strong endorsement from Witness Jester, as he
2 indicates his preference for option 2 on page 18 lines 15 to 18: “However, this
3 approach (option 1) does not actually adjust the nominal MW of customer demand
4 for the seasonality of the resources needed to support that load. I recommend
5 adopting my second option.”

6

7 **Q16. What is your opinion of Jester’s option 2 (WSCI)?**

8 A16. The option 2 proposal warrants rejection due to the lack of compelling evidence
9 from Witness Jester that the 4 Coincident Peak (4 CP) method is obsolete, or that
10 the WSCI proposal more accurately represents the primary cost drivers for the \$10
11 billion in embedded costs of production plant in the as-filed Production COSS.
12 Additionally, the MISO Seasonal Resource Adequacy construct, which was
13 implemented in 2023, is relatively new. Consequently, there is insufficient data to
14 fully comprehend the potential fluctuations in the apportionment of production
15 plant costs across different classes over time based on this proposal. Moreover, as
16 I describe above, the MISO construct has never been the basis for utilizing 4 CP for
17 the demand portion of production plant and, as such, the fact that the MISO construct
18 is changing is not itself a basis to utilize it. Witness Jester offers no affirmative
19 argument for why using a MISO-basis is fundamentally more appropriate than the
20 longstanding, Commission approved approach to production plant cost allocation.

21

22 **Q17. What additional concerns do you have with these proposals?**

23 A17. Witness Jester states on page 17 lines 7 to 10 that “With the combination of both
24 seasonal reserve margins and seasonal accreditation, it is entirely possible that
25 customer demand in some season will drive a need for additional Production Plant

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1 resources even though demand in that season is distinctly lower than in the 4CP
2 summer that DTE Electric has traditionally used.” This perspective is speculative
3 (“it is entirely possible”) and focused on incremental resources while ignoring the
4 primary drivers and conditions that drove the embedded costs of capacity incurred
5 by DTE to serve its customers.

6

7 **Q18. Did MNSC evaluate the class impacts of utilizing the allocators sponsored by**
8 **Witness Jester ?**

9 A18. Yes. Witness Denzler, after receiving options 1 and 2 as calculated by MNSC
10 Witness Jester, proceeds to update the Company’s as-filed Production COSS and
11 provides the revenue requirement impacts on customer classes in Figure 1 of his
12 direct testimony. He concludes with a recommendation, specifically on page 19,
13 lines 19 to 20 to “adjust the UCOS Production allocations based on the
14 recommendations of the MNSC Witness Jester.”

15

16 **Q19. Do you have any observations regarding the class impacts of Witness Jester’s**
17 **proposals as provided by Witness Denzler in his Figure 1 table?**

18 A19. Yes. I have concerns regarding the large increases to the D2 Residential Space
19 Heating class resulting from Witness Jester’s allocation proposals. While the
20 Company calculated an as-filed production revenue requirement of \$20.630 million
21 for the D2 Residential Space Heating class, Witness Jester’s option 1 proposal
22 would increase the amount to \$66.481 million and his option 2 proposal would
23 increase the amount to \$63.214 million. Both proposals reflect increases of greater
24 than 200 percent. Such drastic hikes in costs would be detrimental to the customers
25 in this class, and suggests structural inconsistencies in the analysis that should give

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1 the Commission substantial pause when considering it as evidence in support of the
2 proposal.

3

4 **Q20. Please provide a summary of your conclusions and recommendations**
5 **regarding Witness Jester and Denzler's arguments and proposals?**

6 A20. The following are my conclusions and recommendations:

7 The continued application of the Commission-approved 4 CP method for the
8 production plant allocator is appropriate. The updated system demand tests confirm
9 DTE continues to be a summer peaking utility supporting the use of the 4 CP
10 method. Witnesses Jester and Denzler have not shown that their proposals, argued
11 based on changes to the MISO-construct, more appropriately reflect the cost drivers
12 for the \$10 billion of production plant embedded costs in the Company's revenue
13 requirement.

14

15 Additionally, the current 4 CP method for the allocation of capacity revenue
16 requirement, as detailed in Exhibit A-16 Schedule F1.5 (capacity charge revenue
17 requirement by class), should remain as is. Any changes should only be considered
18 if the Commission decides to alter the existing 4 CP method for apportioning
19 production plant costs.

20 **MNSC Witness Jester's Proposal to Analyze Seasonality and Distribution Costs in**

21 **Next Rate Case**

22 **Q21. What is MNSC Jester's recommendation regarding seasonality?**

23 A21. On page 28, lines 1 to 3, Witness Jester recommends that "the Commission require
24 that DTE Electric file in its next rate case an analysis of the seasonality for cost

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1 causation of distribution costs and distribution rate designs consistent with that
2 seasonality.”

3

4 **Q22. What is MNSC Witness Woolley’s opinion on this issue?**

5 A22. In his direct testimony on lines 1 to 10 of page 11, Witness Woolley expresses
6 disagreement with the allocation for “distribution system maintenance and
7 upgrades based on peak loads,” stating that it does not properly reflect the factors
8 that contribute to transformer aging.

9

10 **Q23. How does MNSC Witness Jester support his recommendation on this issue?**

11 A23. Witness Jester’s argument is largely based on the accounts of MNSC Witnesses
12 Gard and Woolley. Witness Jester states on page 23 lines 10 to 18 of his direct
13 testimony, “As MNSC witness Graham Woolley shows, the effective capacity of
14 the distribution system is also seasonal. Currently aging of line transformers occurs
15 almost exclusively occurs during Summer months June through August. As both
16 he and MNSC witness David Gard show, utilization of the effective capacity of the
17 distribution system is highly seasonal, both because nominal loads are lower in non-
18 summer seasons but also because transformer effective rating is higher when
19 ambient temperatures are lower. As with Production Plant capacity that varies
20 seasonally, the proper basis for both cost of service and rate design of distribution
21 costs is the degree of capacity utilization, not nominal loading.”

22

23 Additionally, he states on page 24 lines 20 to 22 that “we are presenting the
24 transformer analysis to illustrate that this is a significant consideration, but ambient

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1 temperature is important to most elements of the distribution system and should be
2 considered across all of those elements. “
3

4 **Q24. How do you respond to Witnesses Jester and Woolley?**

5 A24. DTE Witness Deol will address the technical points raised by MNSC Witness
6 Woolley while I will respond to the COSS implications. As for the
7 recommendations and defined benefits of Witnesses Jester’s and Woolley’s
8 proposal, they are ambiguous. Witness Woolley has voiced objections to the
9 current method of allocating transformers but hasn’t offered any alternative
10 methods for consideration. Meanwhile, Witness Jester notes that transformer aging
11 mainly occurs during the summer and urges DTE to conduct “an analysis of the
12 seasonality affecting the causation of distribution costs and the corresponding rate
13 designs,” yet he fails to provide concrete details for evaluation. It is unclear if
14 Witness Jester is suggesting an independent study or a supplemental COSS to
15 assess the seasonality of distribution cost causation. Questions such as whether the
16 study should cover only plant costs or include operating and maintenance expenses,
17 or whether it should encompass an examination of distribution allocators in the
18 COSS are not addressed in MNSC’s testimony. The Company would not have
19 sufficient time to review these details in the event they are provided later in this
20 proceeding. Besides the previously mentioned reasons, the Company believes it
21 should not be required to invest the significant time and resources needed to
22 perform a study, merely because an intervenor might be curious or to fill some
23 undefined future data interest.
24

25 **Q25. Do you have any other objections to their proposal?**

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1 A25. Yes. Integrating seasonal variations into the distribution COSS model, taking into
2 account Witness Jester's assertion that transformer aging "almost exclusively
3 occurs during Summer months June through August" appears to support the idea
4 of allocating distribution costs based on summer peak demands when ambient
5 temperatures and customer loads are simultaneously at their highest. This approach
6 would align with the use of 4 CP method for allocating the demand portion of
7 production plant costs. However, the Company disagrees with this approach as it
8 deviates from the Commission-approved non-coincident class peak (NCP)
9 allocators.

10

11 Moreover, it is crucial to weigh the benefits of incorporating seasonality against the
12 risk of complicating the COSS model further. The existing model is already
13 extensive, with over forty workpapers, nearly ninety allocation schedules, and
14 thousands of Excel rows. Adding seasonal factors could expand its complexity
15 without any evidence that it would yield a more accurate result.

16

17 **Q26. Please summarize your recommendation on this topic.**

18 A26. The suggestion by Witness Jester for the Company to perform an analysis on
19 seasonality and distribution costs for the upcoming rate case is deemed
20 insufficiently detailed. Additionally, the Company opposes the consideration of
21 alternatives to the Commission-approved class NCP allocators for apportioning
22 distribution plant costs by voltage level, particularly based on summer peak
23 demands. Company Witness Deol rebuts Witness Woolly's assertions. Finally, the
24 increased complexity that Witnesses Jester's and Woolly's proposed analysis
25 would add to the COSS in terms of time and resources required for completion, in

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1 addition to the absence of clearly defined benefits, lead to the conclusion that this
2 recommendation should not be considered.

3

4 **Energy Michigan Zakem's proposal to alter the State Reliability Mechanism (SRM)**
5 **capacity charge calculation**

6 **Q27. What is your response to Energy Michigan Witness Zakem's proposal to**
7 **remove \$260.787 million of fuel cost in the SRM capacity charge?**

8 A27. DTE Witness Burgdorf addresses the points raised by Witness Zakem while I will
9 address the impacts to the SRM capacity charge. DTE Witness Burgdorf asserts in
10 rebuttal that excluding the \$260.787 million of purchased power energy from the
11 "energy sales revenue net of fuel costs" in Exhibit A-26 would reclassify this
12 expenditure as a capacity-related costs. Witness Burgdorf requested I perform an
13 analysis of how treating the purchased power energy as a capacity cost would affect
14 the SRM capacity charge.

15

16 Exhibit A-38 Schedule CC2 offers a comparative analysis of DTE's as-filed SRM
17 capacity charge, detailed in column (a) of the exhibit. It also includes the revised
18 calculation in column (b), which integrates the reclassification of the \$260.787
19 million as capacity cost as asserted by Witness Burgdorf. The analysis indicates
20 the SRM capacity charge remains unchanged.

21

22 **Q28. What is your conclusion on this topic?**

23 A28. If purchased power energy were reclassified as capacity costs as asserted by Witness
24 Burgdorf in his rebuttal testimony, this reclassification would not alter the SRM
25 capacity charge from the Company's as-filed amount.

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1 **Staff Proposal to Modify Allocation of Purchased Power Capacity in COSS**

2 **Q29. Can you describe Staff Witness Pung's proposal to change the allocation of**
3 **purchased power capacity in the COSS?**

4 A29. Staff Witness Pung describes his proposal on page 12, lines 22 to 26 of his direct
5 testimony, stating that "Staff recommends that allocator 255 be used to allocate
6 purchased power capacity costs in alignment with the Commission's long-standing
7 practice of recognizing the dual nature of production assets. Allocator 255 is a 4
8 CP 75/0/25 allocator and would align the Company with Michigan's other large
9 electric provider, Consumers Energy Company."
10

11 **Q30. What is the current allocation of purchased power capacity and energy costs**
12 **in the DTE Electric's COSS ?**

13 A30. The division of purchased power into capacity and energy costs is provided by
14 Company Witness Burgdorf in Exhibit A-26 and imported into the COSS. The
15 ongoing use of direct demand and energy allocators for the allocation of these costs
16 within the COSS is an appropriate reflection of cost-causation. The Company
17 allocates purchased power capacity using 4 CP 100-0-0 demand less R10 (allocator
18 251) and purchased power energy using 0-0-100 energy less R10 (allocator 111).
19 These allocators have been consistently applied in the calculation of approved
20 tariffs in the previous seven DTE electric rate cases by DTE (U-17767, 18014,
21 18255, 20162, 20561, 20836, and 21297).
22

23 **Q31. What is your recommendation on this issue?**

24 A31. The Company proposes to continue allocating purchased power capacity using 4
25 CP 100-0-0 demand less R10 (allocator 251) and purchased power energy using 0-

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1 0-100 energy less R10 (allocator 111). Should the Commission agree with Staff
2 Witness Pung's proposal and change the allocation to align the allocation of
3 purchased power capacity with the current allocator use for production plant using
4 allocator 255 (4 CP 75-0-25), it would also be prudent to ensure consistency in the
5 allocation of purchased power energy and fuel costs. Currently, fuel costs are
6 allocated using using allocator 192 (12 CP 10-0-90).

7

8 **MPSC Staff As-Filed Excel COSS Model Errors**

9 **Q32. Did you identify any errors in MPSC Staff's as-filed Excel COSS model?**

10 A32. Two minor errors were identified in Staff's as-filed Excel COSS model which
11 should be corrected for the final order.

12

13 1) D13 Incremental Distribution Revenue (COSS Model - Input 1 tab; Row 285):

14 Staff did not update the Company's as-filed \$59 thousand of D13 incremental
15 distribution revenues in the COSS model. DTE calculated a value of \$32
16 thousand using Staff's as-filed numbers. Since D13 incremental distribution
17 revenue is based on proposed primary and transmission rates, it requires a single
18 iteration of distribution COSS and rate design using the steps below:

19 a. First, proposed D13 distribution revenue needs to be calculated in the
20 Rate Design model based on interim proposed transmission and primary
21 rates; these interim proposed rates are calculated based on an interim
22 distribution COSS;

23 b. Second, after proposed D13 distribution revenue has been calculated in
24 the Rate Design model, this value should then be input on Line 7 of tab

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1 “B21.2 D13 Rev” in my workpaper model; this calculates the final value
2 of D13 incremental distribution revenue;

3 c. Finally, the D13 incremental distribution revenue amount should be
4 input on Excel row 285 of the Input 1 tab in the COSS model.

5 2) The Low Income and Senior discounts on Row 265-267 of the Input 1 tab in
6 the COSS model do not match Staff’s as filed numbers.

7

8 **Figure 2 Staff As-Filed and COSS - Low Income / Senior Credits**

(\$ thousands)		Staff As-Filed	Staff COSS
	RIA	\$5,726	-
	LIA	<u>15,360</u>	-
	Total Low Income	21,086	\$30,406
	Senior	4,821	5,810

9

10 **Q33. Can you summarize your recommendations on this topic?**

11 A33. The errors pertaining to the following items should be corrected in the COSS model
12 corresponding to the final order:

13 a) D13 Incremental Distribution Revenues: update amount by performing a single
14 iteration of COSS and rate design prior to calculation of final rates;

15 b) Low Income and Senior Discounts: update COSS model to match approved
16 amounts.

17

18 **Q34. Does this conclude your rebuttal testimony?**

19 A34. 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-21534

REBUTTAL TESTIMONY

OF

PANKAJ SHARMA

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF PANKAJ SHARMA

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Pankaj Sharma (he/him/his). My business address is One Energy Plaza
4 Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC
5 (LLC), as Director – Information Officer within the Information Technology
6 Services (ITS) organization.

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company (DTE Electric or Company)?**

10 A2. Yes.

11

12 **Purpose of Testimony**

13 **Q3. What is the purpose of your rebuttal testimony?**

14 A3. The purpose of my rebuttal testimony is to address the disallowances proposed by
15 Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
16 Witness Rogers and Attorney General (AG) Witness Coppola, as listed below.

17 • Refute Staff Witness Rogers’ proposed Capital disallowance of \$42.6 million
18 in 2024 and 2025 and the associated O&M of \$2.4 million for IT projects with
19 Level 2 cost estimates

20 • Refute Staff Witness Rogers’ proposed capital disallowance of \$11.32 million
21 in 2023, \$0.55 million in 2024 and \$0.82 million in the 2025 and the
22 associated O&M of \$0.08 million for IT projects with Level 3 cost estimates

23

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- 1 • Refute Staff Witness Rogers’ proposed Capital disallowances of the
- 2 individual IT projects listed below totaling \$3.44 million
- 3 ○ Digital Worker Experience EOL
- 4 ○ End of Life Asset Replacements
- 5 • Refute Attorney General (AG) Witness Coppola’s proposed Capital
- 6 disallowances of the individual IT project listed below \$4.17 million:
- 7 ○ Enhanced Document Management Capabilities
- 8 • Refute AG Witness Coppola’s proposed disallowance of \$34.85 million for
- 9 2023 Capital expenditure that the Company underspent

10

11 I am refuting certain positions taken by Michigan Energy Innovation Business
12 Council, the Institute for Energy Innovation, and Advanced Energy United
13 (collectively MEIU) Witness Barnes regarding the Company’s IT Annual
14 Planning Cycle (APC) and prioritization process.

15

16 The absence of a discussion of other matters in my rebuttal testimony should not
17 be taken as an indication that I agree with other aspects of any Staff or Intervenor
18 testimony.

19

20 **Q4. Are you sponsoring any exhibits as part of your rebuttal testimony?**

21 A4. Yes. I am sponsoring the following exhibits:

22	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
23	A-46	KK1	Estimate comparison Level 2 to Level 3
24			for 2024 Spend Year
25	A-46	KK2	Schedule B5.7.1 2024-2025 Projects (\$3M or

Line
No.

1 greater)
2 A-46 KK3 Complete AGDE-3.122 2023 IT Capital Costs
3 A-46 KK4 Over Recovery Analysis - Level 3
4

5 **Q5. Were these exhibits prepared by you or under your direction?**

6 A5. Yes, they were.
7

8 **IT Projects with a Level 2 Cost Estimate:**

9 **Q6. What disallowances did Staff propose related to IT Capital projects with a**
10 **Level 2 cost estimate?**

11 A6. On page 6, lines 6-9 of Staff Witness Rogers Direct Testimony, Staff has proposed
12 a 20% adjustment resulting in total Level 2 Capital disallowances of \$42.60 million
13 (2024 \$22.43 million + 2025 \$20.17 million) as well as an O&M disallowance of
14 \$2.39 million of investments presented in my direct testimony.
15

16 **Q7. What reasons does Staff Witness Rogers provide for these proposed**
17 **disallowances?**

18 A7. On page 6 lines 14-20 and page 7 line 1, Staff Witness Rogers states:

19 "IT projects are given a Level 2 cost estimate more than a year before they are
20 ready for implementation. Additional reviews, final approval, and budget
21 allocation occur after projects are given a Level 2 cost estimate. Many things
22 can happen between the time a project is given a Level 2 cost estimate and the
23 year or more later at the time of execution including a change in scope, a change
24 in schedule, the quote from the vendor, prioritization within the APC, or the
25 necessity of the project altogether."

Line
No.

1 Staff Witness Rogers' direct testimony on page 7, also compared IT projects with
2 Level 2 estimates in Case No. U-21297 (previous rate case) with Level 3 estimates
3 in Case No. U-21534 (this instant case). She then calculated the percentage
4 difference of the Level 2 and Level 3 project costs (to range from -99.86% to
5 277.36%) to determine if the Company had over recovered or under-recovered) as
6 a reason for disallowance. See Witness Rogers' direct testimony page 7 lines 7-16
7 and Exhibit S-15.4. Additionally, she compares DTE Electric's Level 2 estimates
8 to the American Association of Cost Engineering (AACE) Class 3 estimates and is
9 using the lower bound of -20% as the criteria for the recommended disallowance¹.

10

11 **Q8. Do you agree with Staff Witness Rogers' 20% variance recommendation when**
12 **comparing DTE Electric's IT Level 2 estimate classification to AACE Class 3**
13 **estimate?**

14 A8. No, I do not agree. Staff Witness Rogers' selection and recommendation of the
15 lowest accuracy range provided for Class 3 estimates fails to consider that the
16 AACE Class 3 estimates also provide an upper range for Class 3 estimates at
17 +30%². As to the AACE Class 3 estimate criteria, while the Company does not
18 agree that the Commission should apply a wholesale percentage and use an upper
19 range for disallowance, it is more accurate to compare Level 2 estimates to AACE
20 Class 2 estimates. This is consistent with the level of project definition deliverables
21 defined, and reviews completed, as part of the Company's APC process and as
22 defined in Figure 1 below.

23

¹ Rogers DT, page 8, lines 7-19

² https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf?sfvrsn=4, page 3, Table 1

Line
No.

1

Figure 1 AACE Cost Estimate Classes

ESTIMATE CLASS	Primary Characteristic	Secondary Characteristic			
	LEVEL OF PROJECT DEFINITION Expressed as % of complete definition	END USAGE Typical purpose of estimate	METHODOLOGY Typical estimating method	EXPECTED ACCURACY RANGE Typical variation in low and high ranges [a]	PREPARATION EFFORT Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes:

[a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

2

3 **Q9. Should the Commission accept Staff Witness Rogers' recommendation for a**
4 **20% reduction of Level 2 cost estimate IT projects and the proposed**
5 **disallowance?**

6 A9. No, the Commission should reject the proposed Capital disallowance by Staff
7 Witness Rogers of \$42.6 million for 2024 (\$22.4 million) and 2025 (\$20.4 million)
8 and associated O&M of \$2.4 million. The Company's commitment to improving
9 estimates is evident when compared to the cost estimate data in its entirety. These
10 disallowances are each addressed below.

11

Line
No.

\$22.4 million Capital Disallowance for 2024 Spend year:

At the time of the Case No. U-21534 rate case filing, 87 projects were submitted with a Level 2 estimate. Since then, all of these projects have undergone additional review cycles and progressed to the project planning and execution phase. The estimates for these projects have progressed to Level 3. Upon further analysis, 46 projects show a 0% variance and 32 projects are within the variance allowance of a Level 3 estimate (AAE class 1). This analysis is a comparison of the Level 3 estimates to the Level 2 estimates in this instant case. The variance analysis in project estimates demonstrates that the Company is on track to meet its planned capital expenditures in 2024.

Table 1 below shows a high-level breakdown of the 78 identified projects. Detailed information is provided in Exhibit A-46 Schedule KK1.

Table 1 Level 2 to Level 3 Estimate Difference

Level 2 to Level 3 Estimate Difference	No. of Projects	Staff proposed 20% Capital disallowance (\$ millions)
0% Variance	46	\$15.3
Greater than 0% - less than 10% Variance	32	\$5.6

14

As shown above these 78 project estimates should be considered Level 3 and therefore, at a minimum, \$20.9 million out of the \$22.4 million of Staff's recommended Capital disallowance should be rejected.

\$20.2 million Capital Disallowance and \$2.4 million O&M for 2025 Spend year:

Line
No.

1 I do not agree with Staff's recommended Capital Disallowance of \$20.2 million
2 and O&M disallowance of \$2.4 million in 2025 for several reasons. First, Staff
3 Witness Rogers claims that the Level 2 cost estimates are obtained prior to a
4 comprehensive review. As represented in my Revised Direct Testimony in Figure
5 1 on page 7, projects in the N+2-year planning cycle are in the base plan, which I
6 have secured approval of in the financial base plan from the Technology Investment
7 Committee. Additionally, Level 2 cost estimates are comprehensive by cost type
8 and phase (where applicable to the project) and have been supported by the IT
9 architecture team. IT business case costs are estimated as part of a rigorous APC
10 process where detailed estimates (Level 2) are developed, which include labor,
11 software, hardware, and vendor/consulting costs. The estimates are developed
12 through input and reviews from eight discreet IT subject matter experts (SME)
13 teams based on Scope, Technology, historical data. and vendor quotes. All
14 estimates are then reviewed and validated against Company policies, including the
15 capitalization policy. At project execution, the Level 2 estimates are further vetted
16 and refined before transitioning into a Level 3 estimate. Therefore, given the
17 comprehensive and diligent reviews conducted for development of the Level 2
18 estimates which are in alignment with the AACE Class 2 estimates, the 20% blanket
19 disallowance of \$20.2 million Capital disallowance and \$2.4 million O&M for
20 2025 should be rejected.

21

22 **IT Projects with a Level 3 Cost Estimate:**

23 **Q10. What disallowances did Staff propose related to IT capital projects with a**
24 **Level 3 cost estimate (page 10, lines 18-19 and page 11, lines 1-2)?**

Line
No.

1 A10. Staff Witness Rogers recommends a 10% disallowance to IT projects with a Level
2 3 cost estimate resulting in total capital disallowances of \$12.68 million as well as
3 an O&M disallowance of \$0.08 million.

4

5 **Q11. What reasons does Staff Witness Rogers provide for these proposed**
6 **disallowances?**

7 A11. On page 11, lines 3-8 of Staff Witness Rogers' direct testimony states:

8 Staff recommends a 10% disallowance to IT projects with a Level 3 cost
9 estimate due to their inaccurate nature. Using a spreadsheet of IT projects with
10 Level 3 cost estimates provided through audit in Case No. U-21297, Staff
11 compared the then Level 3 cost estimate with the actual cost in the instant case.

12

13 **Q12. Do you agree with Staff Witness Rogers' -10% variance recommendation**
14 **when comparing DTE Electric's U-21297 Level 3 cost estimates with U-21534**
15 **Actuals?**

16 A12. No, I do not agree. Staff compared the Level 3 cost estimates in Case No. U-21297
17 for 2022 and the actual cost in the instant case for 2022 for the basis of 10% blanket
18 disallowance of all Level 3 estimates. As per the analysis provided by Staff in
19 Exhibit S-15.6 titled "Comparison of Level 3 Cost and Actual Costs," annual costs
20 for projects were used to determine variance. However, this provides only a partial
21 view of total project costs and should not be the determining factor for a blanket
22 10% disallowance for all Level 3 projects. For determination of over recovery or
23 under recovery, the total costs approved for cost recovery in Case No. U-21297
24 should be compared to costs submitted as part of the instant rate case within the 36
25 months ending December 31, 2024.

Line
No.

1 As reflected in Exhibit A-46, Schedule KK4, titled "Over Recovery Analysis -
2 Level 3," the Company conducted an analysis for all 70 projects identified as over
3 recovered projects, comparing the total costs approved for recovery in Case No. U-
4 21297 to the costs submitted as part of the instant rate case within the 36 months
5 ending December 31, 2024. Out of the 70 projects identified as over recovered
6 projects in Exhibit S-15.6, 49 projects were identified to be within the variance
7 specification allowance, as these may contain Actuals and Level 1, Level 2 and
8 Level 3 estimates. Therefore, these 49 projects should not be considered as part of
9 the over recovery.

10
11 Additionally, Witness Sharma's Revised Direct Testimony in this case included
12 detailed commentary explaining why variances greater than 20% occurred for 13
13 projects. It is imperative to note that some of these variances were a result of
14 efficiency gained during project planning and execution, such as reduced vendor
15 costs via negotiations and optimized labor costs for technical work. The Company
16 is continuously looking for opportunities to achieve efficiency throughout the
17 project life cycle. Variances that resulted in efficiency gains should not be held
18 against the Company's estimation methodologies and be a reason for the 10%
19 blanket disallowance. Therefore, these 13 projects should also not be considered
20 for the 10% blanket disallowance. Lastly, the remaining 8 projects fall into the
21 category of under recovery due to partial or full disallowance from Case No. U-
22 21297. These projects had been initiated with anticipation for approval.

23
24 Also note Figure 2 below. A detailed analysis for all 70 projects has been provided
25 in Exhibit A-46, Schedule KK4, Over Recovery Analysis - Level 3.

Line
No.

1

Figure 2 Key projects showcasing the above reasoning

Staff Analysis comparing Annual costs									Company's Analysis comparing costs within 36 month period ending Dec 31, 2024					
Exh. A-24 N3 Line No.	Spend Year	Business Case Name	IT Portfolio	Total Projected IT Capital Cost (\$)	Cost Estimate Level	Actual Cost	Difference	Percent Difference	Overall project cost Approved U-21297	Overall project cost submitted for U-21534	Difference Between Approved U-21297 and Requested in U-21534	Overall Variance (Approved in U-21297 Vs. Requested U-21534)	Variance category	Reason Details
119	2022	API Integration Security Gateway and API Layer	Customer Service	\$ 1,550,000	Level 3	\$80,000	-\$1,470,000	-94.84%	\$ -	\$ 100.00	\$ 100.00	100%	Under recovery greater than 20%	Overall project disallowance in U-21297, but project was initiated
180	2022	Fuel Supply Application Health	Plant and Field	\$ 470,000	Level 3	\$387,000	-\$83,000	-17.66%	\$ 1,239.60	\$ 1,240.00	\$ 0.40	0%	No Variance - Overall project Spend same	N/A
279	2022	Threat Intel module	Information Technology for IT	\$ 600,000	Level 3	\$524,000	-\$76,000	-12.67%	\$ 1,040.93	\$ 567.00	\$ (473.93)	46%	Over Recovery greater than 20%	External resource labor savings with AI capabilities available in the Palo Alto XSOAR solution

2

3 **Q13. Should the Commission accept Staff Witness Rogers' recommendation for a**
4 **10% reduction of Level 3 cost estimate IT projects and the proposed**
5 **disallowance?**

6 A13. No, based on the analysis provided above and supplemented by Exhibit A-46 KK4,
7 the Commission should fully reject Witness Rogers's recommendation for a blanket
8 Level 3 Capital disallowance of \$11.32 million for 2023, \$0.55 million for 2024,
9 \$0.82 million for 2025 and the associated O&M of \$0.08 million in the test year.

10

Individual IT Project Disallowances:

12 **Q14. Are there any individual IT Capital projects recommended for disallowance**
13 **by the Staff?**

14 A14. Yes, Staff Witness Rogers recommended a total of \$3.44 million in Capital
15 disallowances for the following IT projects:

- 16 • Digital Worker Experience EOL
- 17 • End of Life Asset Replacement

18

Line
No.

1 Digital Worker Experience EOL

2 **Q15. Why does Staff Witness Rogers recommend a disallowance for the Digital**
3 **Worker Experience EOL?**

4 A15. On page 15, lines 6 -20 and page 16 lines 1-4 Staff Witness Rogers in her direct
5 testimony states:

6 Staff's recommended adjustment is due to the Company's lack of support for
7 the full requested expense. In testimony, DTE provided Table 2, Endpoint
8 Devices Replaced by Year. This table supports the total number of laptops,
9 desktops, monitors, and tablets replaced in 2023, 2024, and 2025. Through
10 audit, Staff requested the cost of each individual laptop, desktop, monitor, and
11 tablet. The Company responded with the following prices: laptop kits- \$1655,
12 desktops- \$1105, monitors- \$165, and tablets- \$795. Using the number of
13 devices replaced from Table 2 and adding 125 units (at the most expensive
14 cost) for new hires and replacements, Staff calculated the total cost of the
15 devices from the information provided and the difference from the requested
16 expense. The Company states that in 2023, devices were deployed to support
17 ADMS, primarily in vehicles, requiring additional docks, cabling harnesses,
18 and installation, at a cost of \$0.8 million. Removing that expense from the
19 \$1.743 million difference in 2023 calculates to an expense difference of \$0.943
20 million. Staff's Total Recommended Adjustment for each year is the amount
21 that is unaccounted for. The Company failed to provide evidence in support of
22 these remaining costs for the Digital Worker Experience EOL.
23

24 **Q16. Do you agree with Staff Witness Rogers' recommended disallowance for the**
25 **Digital Worker Experience EOL?**

26 A16. No, I do not agree with Staff Witness Rogers' recommendation. Witness Rogers
27 used information from my Revised Direct Testimony, Table 2 Endpoint Devices
28 Replaced by Year on page 112. She also used information provided in the audit
29 response DR-1 Question No. 31 which read as "Regarding the Digital Worker
30 Experience Electric EOL project (Exhibit A-24 Sch N3 line 304), please provide
31 the cost of each individual laptop, desktop, tablet, and monitor". The information
32 provided in the audit response included quantity of units and devices unit cost only,
33 Refer to Exhibit S-15.7. It did not include labor costs required for configuration,

Line
No.

deployment and testing of the devices. Staff recognized the \$0.8 million required to support ADMS, however there is still a difference of \$0.94 million needed for the labor associated with the devices. Also, the difference of \$0.94 million for 2023, \$0.96 million for 2024 and \$1.04 million for 2025 are labor costs for the respective years and must be included when calculating total project costs as shown in Table 2 below:

Table 2 : Cost Breakdown for Digital Worker Experience EOL

	Refresh Year		
	2023	2024	2025
Device - Laptop	617	800	700
\$1,655 (Cost per Unit)	\$1,021,135	\$1,324,000	\$1,158,500
Device - Desktop	1	100	185
\$1,105 (Cost per Unit)	\$1,105	\$110,500	\$204,425
Device - Monitor	180	100	100
\$165 (Cost per Unit)	\$29,700	\$16,500	\$16,500
Device - Tablet	25	40	28
\$795 (Cost per Unit)	\$19,875	\$31,800	\$22,260
New hires Devices	125	125	125
\$1,655 (Cost per Unit)	\$206,875	\$206,875	\$206,875
Total Device Costs	\$1,278,690	\$1,689,675	\$1,608,560
Additional labor cost (ADMS)	\$800,000	\$0	\$0
Labor Costs	\$943,310	\$960,325	\$1,041,440
Requested Expense	\$3,022,000	\$2,650,000	\$2,650,000
DIFFERENCE	\$0	\$0	\$0
TOTAL RECOMMENDED ADJUSTMENT	\$0	\$0	\$0

As shown above in Table 2, upon addition of the labor costs to the total requested expense reflects the same total amount as provided in Exhibit A-24 Sch N3 line 304-306. Therefore, the recommended adjustment of \$2.95 million for Digital Worker Experience EOL by Witness Rogers in Exhibit S-15.7 should be rejected.

Line
No.

1 End of Life Asset Replacement

2 **Q17. Why does Staff Witness Rogers recommend a disallowance for the End-of-Life**
3 **Asset Replacement?**

4 A17. On page 17, lines 1 -9 Staff Witness Rogers states:

5 ...the End of Life Asset Replacements project had a variance of \$6.5 million
6 more in the 36 months ending December 31, 2024, than was approved for cost
7 recovery in U-21297, and \$6.1 million of that variance was due to the purchase
8 of a 3 year license purchase of VMWare in 2022. Company testimony also
9 includes a 2025 Capital expenditure request for the renewal of the VMWare 3
10 year license as its own project at a cost of \$5.6 million. The Company does not
11 provide any explanation as to the difference in cost between 2022 and 2025
12 for the 3 year license purchases.

13 **Q18. Do you agree with Staff Witness Rogers' recommended disallowance of \$0.5**
14 **million for the End of Asset Replacement?**

15 A18. No, I do not agree. The cost to renew VMWare licensing in 2022 was \$6.1 million.
16 However, this cost is anticipated to be reduced by \$0.5 million as projected for 2025
17 for a forecasted total of \$5.6 million in 2025. The Company is engaged in vendor
18 negotiations with a focus on increasing efficiency and managing workload with
19 other available technologies to possibly reduce the license costs by \$0.5 million in
20 2025 and reducing our projected VMWare license renewal costs by 8%-10%.
21 Therefore, the Commission should reject the Capital \$0.5 million disallowance for
22 savings captured via negotiations for VMWare licensing renewal for 2025.

23

24 **Q19. Are there any individual IT Capital projects recommended for disallowance**
25 **by AG Witness Coppola?**

26 A19. Yes, AG Witness Coppola recommended a total of \$4.17 million in Capital
27 disallowances for the following IT project:

Line
No.

- 1 • Enhanced Document Management Capability

2

3 Enhanced Document Management Capability

4 **Q20. Why does AG Witness Coppola recommend a disallowance for the Enhanced**
5 **Document Management Capability?**

6 A20. On page 49 lines 3 -9, AG Witness Coppola states:

7 In Schedule B5.7.1, there are two projects with Capital expenditures in excess
8 of \$3.0 million. The first project is on line 9 for Cloud Health and Safety, with
9 Capital expenditures of \$2,518,000 in 2024 and \$582,000 in 2025. The second
10 project is on line 16 for Enhanced Document Management Capability Projects,
11 with Capital expenditures of \$1,218,000 in 2024 and \$2,958,000 in 2025.
12 Given the lack of information, it is not possible to determine what phase those
13 projects are currently in or whether they will be completed by the end of the
14 projected test year and be used and useful.

15

16 **Q21. Do you agree with AG Witness Coppola's recommended disallowance for the**
17 **Enhanced Document Management?**

18 A21. No, I do not agree. AG Witness Coppola's testimony on pages 48-49 incorrectly
19 claims that the Company dismissed the request to provide project phases with
20 related timelines and the current phase of the project for two projects, namely Cloud
21 Health and Safety and Enhanced Document Management Capability. There was a
22 misalignment in the AG's discovery request AGDE-3 Question, No. 123, which
23 has been sponsored by AG Witness Coppola as Exhibit AG-14. The Company
24 responded to AGDE-3, Question No. 123 by providing information on Customer
25 Services IT projects, but the AGDE-3, Question No. 123 included an incorrect
26 reference between the schedule number "Schedule B5.7.1" and the referenced

Line
No.

1 projects “Customer Service IT”. As reflected in Exhibit A-14, AGDE-3, Question

2 No. 123, read as follows:

3 **Refer to Exhibit A-12, Schedule B5.7.1 on Customer Services IT projects.**

4 For each project of \$3.0M or greater in 2024 and 2025, please:

5 a. Describe the project, what is being done, and why it is necessary to
6 undertake each project.

7 b. Provide the project phases of development with related timeline and the
8 identify the current phase of development (i.e., needs identification, initial
9 concept, system requirements, implementation, completed) and the target in-
10 service date.

11 c. Provide the project cost by year from inception to completion.

12 d. Provide a copy of the cost/benefit analysis showing each project was
13 economically justified.

14
15 In response to the misaligned AGDE-3, Question No. 123, the requested
16 information for Customer Service IT projects was provided by the Company.

17 Importantly, Cloud Health and Safety and Enhanced Document Management
18 Capabilities are on Exhibit A-12, Schedule B5.7.1 (Corporate Applications) IT
19 projects. Similar to what was provided in the discovery response AGDE-3 Question
20 No.123 for Customer Services IT projects, please refer to Exhibit A-46, Schedule
21 KK2 for B5.7.1 2024-2025 projects of \$3M or greater.

22 As explained above and supplied in Rebuttal Exhibit A-46, Schedule KK2, the
23 Company provided the requested information that was improperly referenced in the
24 AGDE-3, Question No. 123, along with correct information for the Cloud Health
25 and Safety and Enhanced Document Management Capabilities projects. Hence, the
26 AG’s requests for a disallowance of the Capital cost for Cloud Health & Safety of
27 \$2,518,000 for 2024 and \$582,000 for 2025 and Enhanced document management

Line
No.

1 Capital cost of \$1,218,000 for 2024 and \$2,958,000 for 2025 should be completely
2 rejected because the projects are adequately supported in the record.

3

4 **2023 IT Capital Expenditure:**

5 **Q22. What disallowance did AG Witness Coppola propose related to 2023 IT**
6 **Capital Expenditure?**

7 A22. On page 49, lines 17-18 and page 50 lines 1-3, AG Witness Coppola proposed a
8 \$34.85 million disallowance for the IT Capital expenditure in Exhibit A-12
9 Schedule B5.7.

10 **Q23. What reasons did AG Witness Coppola provide for this proposed**
11 **disallowance?**

12 A23. On page 49 lines 14-18 and age 50 line 1, AG Witness Coppola direct testimony
13 states:

14 In discovery, the Attorney General asked the Company to provide the actual
15 amount of capital expenditures incurred in 2023 in the Information
16 Technology area. The information provided in response to the discovery
17 request shows that for 2023 the Company incurred actual capital expenditures
18 of \$127,456,000. In comparison, the Company had forecasted \$162,310,000
19 for the year in Exhibit A-12, Schedule B5.7. The difference of \$34,854,000
20 should be removed from rate base in this rate case.

21

22 **Q24. Do you agree with AG Witness Coppola's recommendation when comparing**
23 **DTE Electric's Forecasted 2023 IT Capital Expenditure with 2023 Actual**
24 **amount?**

25 A24. No, I do not agree. In Exhibit AG-15, AG Witness Coppola utilized incomplete
26 information derived from Exhibit A-12, Schedule B5.7 that was provided in

Line
No.

discovery response AGDE-3, Question No. 122. AG Witness Coppola has made an incorrect comparison of the 2023 total Capital expenditure projected in U-21534 Capital Exhibit A-12, Schedule B5.7, page 1, to the 2023 Shared Assets actuals provided as part of AGDE-3, Question No.122, Exhibit A-12, Schedule B5.7, page 3. For an appropriate comparison the 2023 total Capital expenditures of \$162,310,00 in Exhibit A-12, Schedule B5.7, page 1, must be compared to the 2023 total actual costs of \$177,344,00 provided in response to AGDE-3 question No.122 Exhibit A-12, Schedule B5.7, page 1.

Table 3 : 2023 Capital Projected Vs 2023 Actuals

Total 2023 Projected IT Capital Costs Exhibit A-12, Schedule B5.7, page 1 Forecast	Total 2023 IT Actuals Costs AGDE-3 Q.122 Exhibit A-12, Schedule B5.7, page 1
\$162,310,000	\$177,344,000

Per the information shown in Table 3, which is also being provided as part of Exhibit A-46, Schedule KK3, Complete AGDE-3.122 response, the \$34.85 million Capital disallowance is due to an incorrect data comparison by AG Witness Coppola and should be fully rejected.

Q25. Should the Commission accept AG Witness Coppola recommendation for \$34.85 million?

A25. No, the Commission should reject AG Witness Coppola's recommendation for \$34.85 million based on the clarification provided above.

Line
No.

1 **Q26. Please describe MEIU Witness Barnes’ understanding of DTE Electric’s IT**
2 **APC process and how it relates to the Company’s proposed deployment**
3 **timeline?**

4 A26. On page 21 lines 9-17, Witness Barnes direct testimony states:

5 Witness Sharma describes the APC generally as representing “how the
6 Company refines its investment strategies, establishes financial targets, and
7 sanctions work,” which it further states also applies to IT investments. As
8 witness Sharma describes it, a central aspect of this process is the use of a
9 Project Prioritization Score (“PPS”) that relies on various inputs intended to
10 reflect alignment of investments with the Company’s strategies and goals. In
11 other words, DTE describes this exercise as a “benefits analysis”, stating “The
12 result of this benefit analysis is a Project Prioritization Score (PPS).” However,
13 witness Sharma states that so-called “nondiscretionary
14 Regulatory/Compliance... projects are considered “must-do” and therefore do
15 not require a benefit analysis.

16

17 **Q27. Do you agree with MEIU Witness Barnes’ conclusion regarding DTE**
18 **Electric’s Annual Planning Cycle and Prioritization process?**

19 A27. No, I do not. Witness Barnes’ understanding of the Company’s methodology for
20 prioritization of projects is incorrect. As mentioned in the DTE Five-Year IT Plan
21 2021-2025 filed in Docket No. U-20561, DTE’s vision for IT (across both its
22 electric and gas utilities) is to enable customer affordability and deliver value faster
23 to customers and communities by removing process, human, and technology
24 friction. Therefore, improving efficiency and reducing barriers using IT.

25 As mentioned in Witness Sharma Revised Direct Testimony, page 7, all non-
26 Discretionary and Discretionary investments and IT projects proceed through the
27 complete DTE IT APC Cadence. The APC is how the Company refines its
28 investment strategies, establishes financial targets, and sanctions work. Non-
29 Discretionary demands (which includes Sustainment, Return to Health and

Line
No.

1 Regulatory and Compliance investments) are considered “must-do’s” and assigned
2 a standard score based on the associated investment category.
3 Regulatory/Compliance investments are categorized as non-Discretionary due to
4 the importance and risk tied to a regulation or order from the Commission/other
5 regulatory bodies. Therefore, an order is a major component in determining the
6 investment type and the PPS score within IT’s APC.

7

8 Also, Discretionary projects undergo a more rigorous analysis and review of both
9 qualitative and quantitative benefits across seven weighted benefit categories for
10 prioritization. The result of this benefit analysis is a PPS. The APC process and PPS
11 scoring consider factors such as strategic fit, financial impact, and operational
12 impact before a project is approved. The PPS score is a scoring and ranking
13 methodology used to bring consistency to how projects across multiple investment
14 portfolios are assessed. Scope for IT non-Discretionary and Discretionary projects
15 must be processed through the IT organizations APC. Once this is completed
16 through the APC project approval process, the requirements will be gathered, and
17 a project implementation timeline will be developed.

18

19 **Q28. Does this conclude your rebuttal testimony?**

20 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)
its rate schedules and rules governing the)
distribution and supply of electric energy, and)
for miscellaneous accounting authority.)

Case No. U-21534

REBUTTAL TESTIMONY

OF

JASON E. SPARKS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JASON E. SPARKS

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Jason E. Sparks (he/him/his). My business address is One Energy
4 Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate
5 Services, LLC.

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my testimony is to rebut the arguments made by:

- 14 • Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
- 15 Witness Rueckert on the \$9.8 million downward adjustment of uncollectible
- 16 expense
- 17 • Soulardarity and We Want Green, Too (collectively DAAO) Witness
- 18 Kinkhabwala's representation of the MPSC website disconnect chart
- 19 • Staff Witness Braunschweig's
 - 20 ○ argument against increasing low-income assistance (LIA) credit
 - 21 from \$40 to \$50
 - 22 ○ proposal to change tariff language of LIA credit
 - 23 ○ disallowance of 2023 residential income assistance (RIA) credit
 - 24 counts for the purpose of recovery

Line
No.

- 1 • Michigan Environmental Council and Natural Resource Defense Council,
2 (NRDC-MEC) Witness Colton's recommendations for the Company's low-
3 income programs
 - 4 ○ Method of recovery for LIA credits
 - 5 ○ RIA and LIA credit changes
 - 6 ○ LSP program changes
- 7 • DAAO Witness Schott's
 - 8 ○ representation of LIA and LSP enrollment methods
 - 9 ○ representation of Company's relationship with MDHHS and
10 community action agencies
- 11 • DAAO Witness Jacob's statements on Low-Income programs and claims
12 that the Company's Shut-Off Protection Plan (SPP) is in violation of the
13 Billing Practice Rules
- 14 • Ecology Center, the Environmental Law & Policy Center, the Union of
15 Concerned Scientists, and Vote Solar (Collectively CEO) Witness
16 Kenworthy's position that energy assistance programs should utilize the
17 MiEJScreen tool.
- 18 • Michigan Municipal Association for Utility Issues (MAUI) Witness
19 Bunch's position on the Company's cash only policy

20

21 The absence of a discussion of other matters in my rebuttal testimony should not
22 be taken as an indication that I agree with other aspects of any Staff or intervenor
23 testimony.

24

25 **Q4. Are you sponsoring any rebuttal exhibits in this proceeding?**

Line
No.

1 A4. Yes. I am sponsoring the following exhibits:

2	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
3	A-41	FF1	Staff UCX Calculation
4	A-41	FF2	AGDE-1.27b Discovery Response

5 **Q5. Were these exhibits prepared by you or under your direction?**

6 A5. Yes, they were.

7

8 **Uncollectible Expense**

9 **Q6. What uncollectible calculation method is Staff Witness Rueckert proposing in**
10 **this case?**

11 A6. Staff Witness Rueckert is applying three key elements in their uncollectible
12 calculation. They include 1) an update to include 2023 actuals 2) the use of present
13 revenues instead of projected revenues, and 3) the removal of full PSCR costs.

14

15 **Q7. Does the Company agree with Staff Witness Rueckert's proposed disallowance**
16 **of \$9.8 million in uncollectible expense (page 5, line 5)?**

17 A7. No. Staff Witness Rueckert's uncollectible expense calculation uses existing
18 revenue instead of projected revenue, which will not result in a reasonable
19 calculation of uncollectible expense when new rates are implemented. In addition,
20 Staff Witness Rueckert's projected billed revenue does not include PSCR revenue,
21 which is not consistent with how the historical uncollectible expense as a percent
22 (%) of revenue is calculated.

23

24 **Q8. Do you agree with Witness Rueckert's use of existing base rates to calculate**
25 **uncollectible expense?**

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1 A8. No. On page 5 of revised direct testimony, lines 12-13 Witness Rueckert describes
2 that using proposed rates will result in an iterative calculation and then goes on to
3 propose current revenue be used instead. The Company disagrees with this
4 approach. It is unreasonable because if new rates are approved, uncollectible
5 expense will be impacted by these new rates, in addition to projected billing
6 determinants. Staff's calculation uses current rates to calculate uncollectible
7 expense. Staff claims use of future revenues at proposed rates creates an iterative
8 calculation for the cost of service study, but provides no evidence as to why that
9 would make its proposal to use existing rates a reasonable approach. The
10 Commission agreed with Staff in its Order in Case No. U-21297 stating "the
11 Commission agrees with the Staff that using present revenue, rather than projected
12 revenue, avoids the creation of an iterative calculation and 'encourages the
13 Company to continually improve efforts to reduce [uncollectible expense] below
14 the amount set in rates.'" However, DTE Electric maintains that using rates
15 currently in place and excluding PSCR revenue is unjust, as it does not provide
16 DTE Electric a reasonable chance to recover uncollectible costs that it will be
17 incurring. Unlike capital expenditures or operation and maintenance expense,
18 which DTE Electric has some degree of control over and may be able to change in
19 response to a Commission order, uncollectible expense is impacted by factors that
20 are outside of DTE Electric's control.

21

22 **Q9. What method are you proposing to Staff's uncollectible expense calculation?**

23 A9. Staff should adopt the methodology that uses the Commission-approved
24 methodology of a three-year average of net write-offs to revenues. This is supported
25 by the direct testimony of AG Witness Coppola on page 110, line 1-3, "the

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1 Commission has stated in several cases that the use of a three-year average ratio of
2 charge-offs to revenues applied to future revenue is the most appropriate way to
3 forecast uncollectible accounts expense". Witness Coppola correctly includes the
4 projected revenue, including PSCR and only updated the 3-year average to include
5 2023. This calculation results in a downward adjustment of \$3.8 million to what
6 the Company initially proposed, bringing the Company's uncollectible calculation
7 from \$50.8 million to \$47.0 million for the projected test year.

8

9 **Q10. What adjustments are you proposing to Staff's uncollectible expense**
10 **calculation?**

11 A10. As seen in Exhibit A-41 FF1-1, the Company does not oppose Staff and the AG
12 including 2023 in the three-year average to determine Net Write-Offs to Revenue.
13 Billed Revenue (line 4) in the Net Write-Offs to Revenue calculations properly
14 include PSCR revenue. For consistency, PSCR revenue should also be included in
15 Projected Billed Revenue (line 7). The Company agrees with the Projected Billed
16 Revenue amount used by AG Witness Coppola in Exhibit AG-41, line 5 of
17 \$6,399,006. This amount includes PSCR and anticipated future revenues and is
18 consistent with DTE Electric's projections shared in Discovery Response AGDE
19 1.27b. (Exhibit A-41 FF2). This change drives a \$6.0 million increase to Staff's
20 uncollectible expense calculation, increasing the total from \$41.0 million to \$47.0
21 million, consistent with the AG's recommendation.

Line
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1 **Disconnects**

2 **Q11. Do you agree with DAAO Witness Kinkhabwala's direct testimony on page**
3 **16, lines 8-9 that DTE's bill affordability is causing non-pay disconnects to**
4 **increase?**

5 A11. No. Witness Kinkhabwala makes a generalized statement of affordability
6 disconnects based on an incorrect understanding of the data behind the chart
7 provided in their testimony.

8

9 **Q12. Does DAAO Witness Kinkhabwala on page 17, lines 3-7 correctly present the**
10 **"Customer Disconnections by Utility" disconnect chart on the Michigan**
11 **Public Service Commission Utility Customer Data Tool website?**

12 A12. No. As part of the Case No. U-20757 Order, utilities were required to provide
13 several data points including but not limited to disconnects due to nonpayment. The
14 disconnect data that DTE provides, is representative of total number of residential
15 premises that were disconnected from 11/1/2019 to the last day of the reporting
16 month that have not been restored as of any reporting month (for ease of reference
17 see Figure below). The data is cumulative and not the number of actual disconnects
18 for any given month.

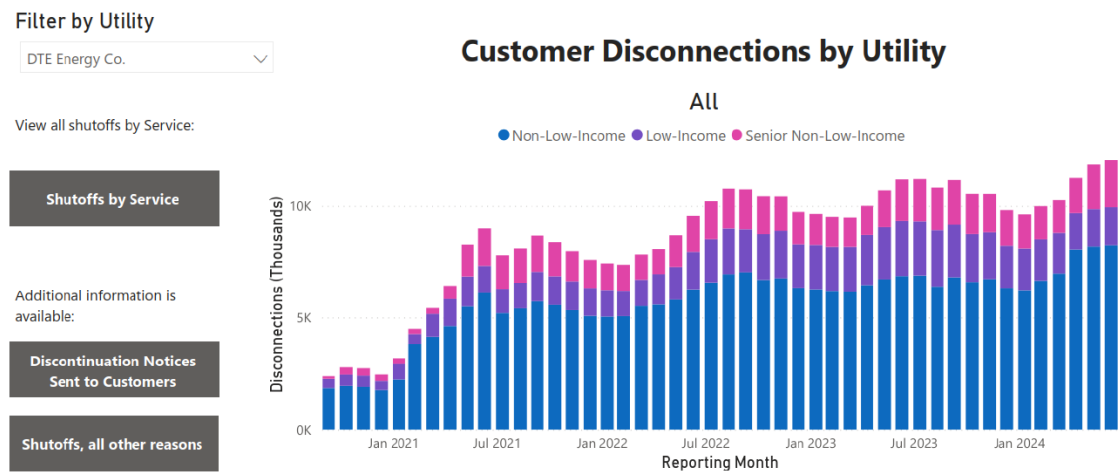


Figure 5: Screenshot from Michigan Public Service Commission Utility Customer Data Tool of historic shutoffs by DTE broken down by income category.

Low Income Programs

Q13. Do you agree with Staff Witness Braunschweig recommendation to reject DTE Electric's proposal to increase the Low Income Assistance (LIA) credit?

A13. No. Witness Braunschweig recommends on page 5, line 19 through page 6, line 2 of their direct testimony that DTE Electric's proposal to increase the LIA credit does not provide a comprehensive analysis and diverse collaborative input the Commission is looking for to inform utility energy assistance change and therefore should be rejected. However, the increase in the credit that is being requested is only to keep it aligned with its original function of assistance. As stated in my direct testimony, in 2015 when the LIA credit was implemented, it gave relief of 43% of a low income customer's bill. The increase to \$50 aims to align the financial support that is so needed and does not change the potential outcomes of the work or potential outcomes of the Commission's Energy Affordability and Accessibility Collaborative (EAAC) workgroups.

Line
No.

1 **Q14. Why does the Company disagree with Staff Witness Braunschweig's**
2 **recommendation to keep the LIA credit at its present \$40 amount?**

3 A14. Witness Braunschweig's direct testimony states that while they believe that
4 Michigan's most vulnerable customers would benefit from additional assistance, it
5 would be better to wait on the analysis being performed in the EAAC workgroups
6 on Percentage of Income Payment Plans (PIPP). Witness Braunschweig gives an
7 estimate target of Q1 of 2025 to propose a resolution to the PIPP analysis which
8 may include additional reform to the LIA credit. Even if a resolution is reached and
9 proposed by Q1 2025, it will take additional time for the Commission to rule and
10 provide the method of implementing such recommendations and further time to
11 retire and implement a new method of integrating the LIA credit funding. In the
12 meantime, there are low-income households struggling with bill affordability and
13 would greatly benefit from the proposed increase in the immediate future.

14

15 **Q15. Is the Company proposing to change the structure of the LIA credit?**

16 A15. No. DTE Electric is only asking to increase the amount of the credit. The eligibility
17 and structural methods of applying the credit will remain in place pending further
18 recommendations by the Commission.

19

20 **Q16. Do you agree with Staff Witness Braunschweig's method of excluding 2023**
21 **RIA enrollment counts when considering forecast projections?**

22 A16. No. Witness Braunschweig states (page 11, line 13-14) that on page 16 of my direct
23 testimony that the RIA counts, "were from billing period end of month snapshots
24 instead of monthly averages, as used in Part III Attachment 5(9)" and that the
25 reported numbers are different. First, to clarify, 2023 RIA counts were not included

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in Part III. Staff's concern about the accuracy of the 2023 RIA counts presented in my direct testimony, due to differences between the data in my direct testimony versus Part III Attachment 5(9), is unwarranted. For 2020 the overall annual average between the two sources remains quite close: 39,867 in my direct testimony versus 39,668 using Part III. In 2021 and 2022 the differences are immaterial: the largest monthly difference between my direct testimony and Part III was only eight customers, with the overall annual average difference being just three customers in 2022 and five customers in 2021. Therefore, excluding 2023 based on the differences between my direct testimony and historical Part III reporting is unwarranted, given the minimal discrepancies observed in the previous years. For ease of comparison, I have included the 2020-2023 data included in my direct testimony and the 2020-2022 data included in the Part III Attachment 5(9) below in Table 1 and Table 2:

Table 1 Electric RIA Customer Counts per Witness Sparks' Direct

Testimony

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
2020	40,841	31,153	42,712	36,033	34,226	37,229	38,366	40,914	40,240	42,742	42,660	51,284	39,867
2021	49,353	47,625	59,867	59,242	56,920	70,009	60,730	60,095	57,133	54,675	52,637	54,668	56,913
2022	55,273	52,472	77,861	64,098	71,279	76,710	70,158	80,906	75,554	77,992	76,119	83,522	71,829
2023	83,898	67,558	84,225	68,573	79,637	74,767	71,061	80,429	77,502	77,240	70,466	70,910	75,522

Table 2 Electric RIA Customer Counts per Part III Attachment 5(9)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
2020	40,632	30,546	42,921	35,150	34,222	36,974	38,501	40,711	40,019	42,557	42,233	51,546	39,668
2021	49,349	47,618	59,861	59,239	56,918	70,001	60,726	60,092	57,131	54,670	52,631	54,664	56,908
2022	55,269	52,469	77,853	64,094	71,276	76,709	70,158	80,901	75,554	77,992	76,119	83,522	71,826

Line
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1 **Q17. Do you agree with Staff Witness Braunschweig that Low-Income Home**
2 **Energy Assistance Program (LIHEAP) funding should be the main**
3 **determinant of RIA enrollment fluctuation (pages 12-13)?**

4 A17. No. While it is true that Covid-related funding increased the number of households
5 applying for and receiving assistance, we cannot determine exactly how many new
6 households became energy assistance recipients without further analysis.
7 Additionally, much of the Covid-related assistance, such as Covid Emergency
8 Rental Assistance (CERA) and Michigan Homeowner Assistance Fund (MIHAF),
9 had broader eligibility criteria than the 150% Federal Poverty Level (FPL) required
10 by RIA. This means that even if a household received Covid-related assistance, it
11 didn't automatically qualify for the RIA credit. Additionally Witness
12 Braunschweig's testimony includes a table on page 13 which aligns LIHEAP
13 funding levels with RIA enrollments. However, the data is not supportive that
14 LIHEAP funding is a predictor of RIA enrollment trends. For example, LIHEAP
15 funding decreased from \$435.5 million to \$166.9 million in the next year, yet RIA
16 enrollments increased. Later, when LIHEAP funding rose to \$269.6 million, RIA
17 enrollments increased further, surpassing the levels seen when funding was at
18 \$435.5 million.

19 Furthermore, DTE Electric's systems automatically enroll customers who receive
20 not just LIHEAP funding, but also Home Heating Credit (HHC) or one-time
21 assistance. Although supplemental funding for LIHEAP has decreased since 2022,
22 HHC funding has increased and remains steady.

23

24 **Q18. Do you agree with Witness Braunschweig (page 14) that because the RIA**
25 **credit requires annual enrollment, that most customers will not re-enroll?**

Line
No.

1 A18. No. While it is true that some households will not reapply to receive the RIA credit,
2 the majority will remain recipients due to auto enrollment by other energy
3 assistance programs as well as self-attestation. Staff has even expressed the
4 importance of making sure that every eligible customer receives this credit. Even
5 with customers not renewing for the credit, it is unlikely that the forecast numbers
6 for the projected test year provided by Witness Braunschweig will revert to the
7 average monthly enrollments of 2021. Even though supplemental funding may be
8 eliminated, the number of households needing it will not.

9

10 **Q19. What is your position on Witness Braunschweig's (pages 14-15) use of the**
11 **ALJ's recommendation in the PFD of Consumer's Energy Case No. U-21389?**

12 A19. The recommendation presented is not relevant to DTE Electric's forecast for two
13 reasons. First, as pointed out in Witness Braunschweig's testimony, the ALJ on
14 page 379 referenced that Consumers presented, "a simple comparison of customer
15 counts for two months one year apart" and that, "the company's projection depends
16 on actual enrollment in March of 2023...". My direct testimony includes all 2023
17 enrollments, which clearly shows the increase in RIA enrollments. Additionally,
18 my forecast incorporated a two-year historical average of the monthly average of
19 enrollments and accounted for the 6% decline in 2023 accounts receiving energy
20 assistance, as detailed in Staff's Exhibit S-17.0 page 1. Second, also on page 379
21 the PFD states, "the PFD agrees with Staff that without a tracker or deferred
22 accounting, over-projection of RIA credits would result in Consumers retaining any
23 overcollection." However, DTE Electric has a tracker in place to correct any over
24 or under projection of enrollments. I would also like to note that Witness

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1 Braunschweig's testimony on page 15, line 12, which references the PFD,
2 inadvertently referred to "DTE" while the actual PFD refers to "Consumers".
3

4 **Q20. What method of LIA Cost Recovery does NRDC-MEC Witness Colton**
5 **recommend?**

6 A20. Witness Colton proposes the Company reconcile actual LIA costs to projected costs
7 on an annual basis where the under-recovered or over-recovered would be tracked
8 and filed as a regulatory asset in future regulatory filings. Witness Colton also
9 proposes that the costs should include incremental and net costs including
10 quantifying the cost benefit of things like impact to uncollectibles, arrears balances,
11 and operational impacts providing the LIA credit to customer's bills.
12

13 **Q21. What is the Company's current method of recovery for LIA expense?**

14 A21. As originally authorized in Case No. U-20561, the Company currently has a
15 mechanism in place to book a regulatory asset for any LIA credits issued above a
16 base amount. Case No. U-20836 clarified that any underspent amounts are netted
17 against (reduce) the regulatory asset. Case No. U-21297 approved the base amount
18 at 32,000 customers with an LIA credit of \$40.
19

20 **Q22. Does the Company agree with NRDC-MEC Witness Colton's proposal to**
21 **include additional cost benefit to uncollectibles when determining the LIA**
22 **expense?**

23 A22. No. The Company's forecasted LIA expense for the projected test year is grounded
24 in historical actuals. These historical figures already account for the benefits of the

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1 LIA credits. Therefore, additional analysis of their impact on uncollectibles is
2 unnecessary.

3

4 **Q23. Do you agree with NRDC-MEC Witness Colton’s recommendation on page 25**
5 **to increase RIA eligibility to 250% FPL?**

6 A23. While the Company acknowledges the necessity for energy assistance for
7 households exceeding 150% of the FPL, DTE Electric is bound by the billing
8 practice rules (460.11(2) and 460.10t(6)(b)). According to these rules, an “eligible
9 low-income customer” is defined as a customer whose household income does not
10 surpass 150% of the poverty level, as determined by the United States Department
11 of Health and Human Services.

12

13 **Q24. Are there any additional recommendations on pages 25-37 for the RIA and**
14 **LIA credit made by NRDC-MEC Witness Colton that you do not support?**

15 A24. Witness Colton has proposed several recommendations, including the application
16 of RIA and LIA credits to non-energy fees or services, arrears, and a tiered approach
17 to credit application. While these suggestions are valuable, they would be more
18 appropriately addressed by the EAAC workgroups currently focused on reforming
19 the RIA and LIA credits. The Company will continue its active participation in
20 these workgroups to identify the most effective solutions for this funding.

21

22 **Q25. What is your response to NRDC-MEC Witness Colton’s recommendations on**
23 **page 49 for modifying the Low-Income Self Sufficiency Plan (LSP), the**
24 **Company’s “arrearage forgiveness program”?**

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1 A25. Under the guidance of the Michigan Department of Health and Human Services
2 (MDHHS) and the MPSC, utilities offer a Michigan Energy Assistance Program
3 (MEAP)-funded Affordable Payment Plan (APP). The Company's APP is known
4 as the Low-Income Self-Sufficiency Plan (LSP). Any structural changes to this
5 program would be addressed by the MEAP workgroup, which includes
6 representatives from Staff, utilities, and various agencies.

7

8 **Q26. Do you agree with DAAO Witness Jacob's position on pages 5-6, that DTE's**
9 **low-income programs are difficult to understand and navigate?**

10 A26. No. DTE utilizes numerous channels to provide information about low-income
11 programs, which are not limited to the Company's website or document portal.
12 DTE hosts face-to-face Community Resource Fairs and Community Pop-ups to
13 allow customers to interact with representatives to address any inquiries and obtain
14 hands-on assistance, in addition to communicating through email and printed
15 correspondence. In addition, DTE Electric employs a team of specialized
16 representatives who connect customers with access to both agency and government
17 programs. This team, known as the Energy Advocacy Group, also navigates
18 customers through applications for energy assistance crisis funding or State
19 Emergency Relief, administered by the MDHHS. Furthermore, DTE employs
20 additional measures to bridge a variety of gaps that our customer base encounters,
21 including those who face literacy challenges with digital technology. While
22 customers seeking energy assistance can work directly with MDHHS or a human
23 service agency, DTE Electric offers customers the opportunity to determine their
24 potential eligibility for energy assistance or for the Shut-Off Protection Program.
25 In those extenuating circumstances in which a customer is facing barriers such as

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1 technology, our specialized team is empowered to dispatch field representatives to
2 assist.

3

4 **Q27. DAAO Witness Jacob claims on page 8 of her direct testimony that there is**
5 **insufficient communication and coordination between DTE Energy and utility**
6 **assistance program providers. Is the communication and coordination**
7 **between DTE Energy and utility assistance programs providers sufficient?**

8 A27. Yes. DTE Energy collaborates extensively with utility assistance program
9 providers, as well as government entities, such as the MDHHS. Specifically, DTE
10 Energy meets individually with all human services agencies that supply MEAP
11 funds to DTE customers needing assistance. Standing meetings are held either bi-
12 weekly or weekly depending on the agency's need and preference, and those
13 meetings serve to provide status updates and address any specific administrative
14 issues. Similarly, DTE has an established meeting cadence with the MDHHS
15 LIHEAP leadership team and the Economic Stability Administration team. These
16 meetings keep communication channels open, addressing any policy or process
17 opportunities, which may include human performance errors such as payments
18 from MDHHS submitted to DTE incorrectly or system defects. Furthermore, DTE
19 is an active participant in the monthly MEAP workgroup meetings which are
20 comprised of the MPSC MEAP team members, MDHHS representatives, as well
21 as grantees and utility providers, and serve the purpose of collaborating on energy
22 assistance solutions.

23

24 **Q28. Does DAAO Witness Jacob correctly represent DTE's cash only policy?**

Line
No.

1 A28. No. Pages 7-8 of Witness Jacob's direct testimony incorrectly states that low
2 income households who miss a bill payment are required to use a DTE kiosk or an
3 authorized payment agent. Missed payments do not result in requirements to use a
4 kiosk or an authorized agent. Additionally, while there is a fee when using an
5 authorized payment agent, there is no fee required when using a DTE kiosk.

6

7 **Q29. Does DTE charge low income customers an inequitable higher rate for energy**
8 **service because of its cash only policy as described by Witness Jacob's**
9 **testimony on page 8?**

10 A29. No. All customers who have made payments with returned checks, credit/debit
11 cards are subject to the policy.

12

13 **Q30. Do you agree with Witness Jacob's position on page 7 on downpayments for**
14 **the Company's Shut Off Protection Plan (SPP)?**

15 A30. No. The Company asks for a 10% downpayment when enrolling customers on SPP
16 for the first time. If the customer defaults on that initial SPP and the Company offers
17 a subsequent SPP, the down payment requirement is higher to help reduce some of
18 the additional arrears the customer accumulated since the first default. The
19 Company believes this to be reasonable.

20

21 **Q31. Do you agree with Witness Jacob's position on page 10-12 that the Company**
22 **does not provide clear information as to how SPP operates?**

23 A31. No. DTE sends customers who have enrolled in SPP an enrollment confirmation
24 communication that very clearly indicates that "every three months, we review your
25 monthly plan amount to make sure it reflects your average energy usage. If the new

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1 average is 5% higher or lower than your current plan amount, we will adjust a
2 customer's monthly plan amount and they will see this adjustment in your next bill.
3 We will send you a notification after our review." So not only do we tell a customer
4 when they enroll but the Company closes the loop every quarter to let the customer
5 know if their bill is staying the same, is going up or going down. This approach
6 helps ensure that customers do not find themselves with a large balance due after
7 12 months because of higher usage than estimated. DTE does not assess a
8 "recalculation fee" as Witness Jacob states.

9

10 **Q32. Do you agree with DAAO Witness Schott's direct testimony on page 43**
11 **reporting of DTE's declining enrollment in affordable payment plans?**

12 A32. No. Witness Schott incorrectly categorizes DTE's SPP with the Company's
13 Affordable Payment Plan, LSP. Enrollments in LSP have remained steady (shown
14 in direct testimony Table 3 LSP Graduate Metrics JES-11).

15

16 **Q33. What is your response to DAAO Witness Schott's position on pages 43 and 44**
17 **that your position as Director of Revenue Management and Protection**
18 **prohibits the Company's ability to address the needs of energy affordability?**

19 A33. While it is understandable to perceive a potential conflict of interest in the dual
20 responsibilities of the Director of Revenue Management and Protection, the role
21 actually serves a more balanced and comprehensive purpose. The position is
22 designed to address the diverse needs of the Company's customer base, which
23 includes both enforcing payment policies and providing support to those in
24 financial distress. The dual responsibilities of the position allow the Company to
25 address affordability challenges more comprehensively.

Line
No.

1 **Q34. Is DAAO Witness Schott's testimony on page 48 regarding amounts collected**
2 **for reconnect and late fees on residential customers, correct?**

3 A34. No. Witness Schott ignores that the data provided on reconnection and late fees are
4 assessments and not necessarily what was collected by the Company. This is noted
5 in Exhibits DAO-139 and DAO-140.

6
7 **Q35. Do you agree with CEO Witness Kenworthy's direct testimony on page 12 that**
8 **energy assistance programs should utilize the MiEJScreen tool?**

9 A35. No. The MiEJScreen would be better served by the agencies that work with
10 households in providing outreach and pathways of energy assistance. Energy
11 assistance is equitable in that any income qualified households can access such
12 assistance and is not limited by demographic or geographic categories. Moreover,
13 DTE does not control the distribution of energy assistance dollars such as LIHEAP,
14 SER, HHC or one-time assistance. Only the LIA and RIA rate base credits are
15 distributed by DTE.

16
17 **Q36. Do you agree with MAUI Witness Bunch's assertion that the Company's cash**
18 **only policy is in violation of the billing practice rules?**

19 A36. No, the language in Section C4.6 of the rate book is a longstanding provision and
20 does not conflict with the billing rules. Importantly, Part 5 of the billing rules, which
21 covers Billing and Payment Standards, does not specify the form that payments
22 must take. Therefore, DTE retains the authority to determine the types of payments
23 it accepts. Furthermore, the Commission approved DTE Electric's cash payment
24 requirement in its Order in general base rate Case No. U-17767.

Line
No.

1 **Q37. Do you agree with Witness Bunch's direct testimony on page 15 that the cash**
2 **only policy will drive an increase in uncollectibles?**

3 A37. No. The assertion made by Witness Bunch lacks analysis to support the claim that
4 the Company's cash-only policy is a significant factor contributing to
5 uncollectibles. Contrary to Witness Bunch's assertion, the Company's cash-only
6 policy serves as a proactive measure to curb the escalation of arrears resulting from
7 returned payments. When a customer incurs consecutive returned payments, they
8 not only face the original unpaid balance but also an additional month's bill, which
9 can accumulate until the point of disconnection. This sequence of events
10 contributes to an increase in uncollectibles.

11

12 **Q38. Do you agree with Witness Bunch's recommendation on page 12 to assess**
13 **deposits instead of requiring cash only payments for customers who**
14 **demonstrate the behavior of paying with returned checks or closed accounts?**

15 A38. No. The suggestion to impose a deposit requirement on customers prone to making
16 payments with bad checks or from closed accounts does not address the core issue.
17 Such a requirement does not guarantee the elimination of insufficient funds
18 scenarios, as it does not inherently change the method of payment—merely the
19 preliminary conditions of service.

20

21 **Q39. Do you agree with Witness Bunch's overview of the Company's cash only**
22 **policy he provides on pages 7-8 of his testimony?**

23 A39. No. In recognizing the diversity of customer circumstances, the Company carefully
24 considers those with current balances, inadvertent errors, and instances of identity
25 theft. To elucidate the cash-only restriction process:

Line
No.

- 1 • Second Chance Provision: Customers who are either not in arrears or have
- 2 arrears of \$100 or less at the time of payment will not activate the cash-only
- 3 restriction, thus receiving a second opportunity. This policy allows
- 4 customers sufficient time to rectify the issue of the returned payment and
- 5 maintain access to various payment methods.
- 6 • Automatic Payment Plan Consideration: Customers enrolled in the
- 7 automatic payment plan who inadvertently enter incorrect payment
- 8 information are permitted up to two returned payments before the cash-only
- 9 restriction is applied.

10 The Company is committed to continuous improvement and actively reviews both
11 internal feedback from the contact center and external customer complaints. This
12 ongoing evaluation process ensures that our policies remain effective and fair, and
13 we remain open to further refinements to effectively reduce the incidence of
14 uncollectibles.

15

16 **Q40. Does this conclude your rebuttal testimony?**

17 A40. 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-21534

REBUTTAL TESTIMONY

OF

RACHEL C. STEUDLE

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF RACHEL C. STEUDLE

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Rachel Steudle, Director of Tree Trimming, One Energy Plaza, Detroit,
4 Michigan 48226. I am employed by DTE Electric Company, known simply as DTE.

5

6 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
7 **Company (DTE Electric or Company)?**

8 A2. Yes.

9

10 **Purpose of Testimony**

11 **Q3. What is the purpose of your rebuttal testimony?**

12 A3. The purpose of my rebuttal testimony is to refute certain positions taken by the
13 other parties as follows. The absence of a discussion of other matters in my
14 testimony should not be taken as an indication that I agree with all other aspects of
15 intervenor testimony.

16 • Attorney General (AG) Witness Coppola's recommendation to disallow
17 capital, regulatory asset and O&M related to the Tree Trim program,

18 • Attorney General (AG), Michigan Environmental Council (MEC), Natural
19 Resource Defense Council (NRDC), collectively AG-MN Witness
20 Alvarez's and Citizens Utility Board of Michigan, Michigan Environmental
21 Council, and Natural Resources Defense Council, collectively CUB-MN
22 Witness Denzler's recommendations around future data / analysis to be
23 provided by the Company,

24 • Ann Arbor Witness Giacobazzi's commentary on tree trimmers identifying
25 methane leaks while trimming,

Line
No.

- 1 • AG-MN Witness Alvarez's and Ann Arbor Witness Stultz's general
2 mischaracterizations of the Company's tree trimming program,
3

4 **Q4. Are you sponsoring any exhibits in this proceeding?**

5 A4. Yes. I am sponsoring the following exhibits:

6	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
7	A-42	Schedule GG1	Emergent Capital Savings Calculation
8	A-42	Schedule GG2	Tree Trim Risk Model NPV
9	A-42	Schedule GG3	AGDE-4.167(S1)
10	A-42	Schedule GG4	AGDE-4.160a
11	A-42	Schedule GG5	DEAG-2

12

13 **Part 1 - Recommended Disallowance by Witness Coppola**

14 Capital Disallowances

15 **Q5. What is the AG Witness Coppola's recommendation with regards to**
16 **accounting for Tree Trim Surge savings?**

17 A5. Beginning on page 33, line 19 and running through page 34, line 2 of his direct
18 testimony, AG witness Coppola recommends the Commission remove \$66.9
19 million in cost savings from the Company's forecasted capital expense in 2024 and
20 \$59.6 million in 2025 due to his calculation of savings arising from the Tree Trim
21 Surge program.

22

23 **Q6. Does the Company agree with the recommended disallowance in Capital?**

24 A6. No.

Line
No.

1 **Q7. Does the Company agree that the Tree Trim Surge will result in emergent**
2 **capital savings?**

3 A7. Yes.

5 **Q8. Did the Company account for these savings with respect to emergent capital?**

6 A8. Yes. In Exhibit 12, Schedule B 5.4, p. 1, line 6, the Company reduces the requested
7 emergent capital for 2024 by \$20.8 million and for 2025 by \$21.4 million, reflecting
8 the expected savings we will see from both tree trim and non-tree trim investments
9 in strategic capital.

10

11 **Q9. How did the Company determine these amounts?**

12 A9. These outputs came from the Company's Reliability Model. Witness Kryscynski
13 discusses the model in detail in his direct testimony beginning on page 69, line 8.
14 The model itself has also been provided as WP AJK U-21534 Reliability Model.

15

16 **Q10. How does the Reliability model calculate expected savings?**

17 A10. The model includes a circuit-by-circuit average event volume based on circuit
18 performance from 2018-2022. The model includes both tree-related and non-tree
19 related event volumes. When tree trim or other reliability investments are
20 performed on a circuit, the model assumes the event volume on that circuit
21 decreases. Circuits with no reliability investments will experience an increase in
22 event volume. Events also have an average cost per event based on historical
23 averages. The model calculates expected savings by taking the difference from the
24 baseline event volume (2018-2022 average) and the modeled event volumes in
25 2024 and 2025.

Line
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1 **Q11. How does Witness Coppola determine his recommended disallowance?**

2 A11. Witness Coppola points to the Company's response in discovery in which the
3 Company was asked to compare the relative cost savings expected to be realized
4 by executing the Surge, versus not executing the Surge (page 33, line 13-19).
5 Specifically, this discovery relies on data presented in U-21534 Exhibit A-22.

6

7 **Q12. What is the purpose of U-21534 Exhibit A-22?**

8 A12. U-21534 Exhibit A-22 is an output of the Tree Trim Surge model which was
9 developed as part of Case No. U-20162 to demonstrate the relative benefit for the
10 Tree Trim Surge compared to a status quo scenario of not executing the Surge.

11

12 **Q13. What is the status quo scenario?**

13 A13. The status quo scenario assumes the Company did not receive the Surge funding.
14 In this scenario, the Company is limited in the number of miles it can reclaim
15 annually and is unable to fully maintain on-cycle miles as they return for trimming.

16

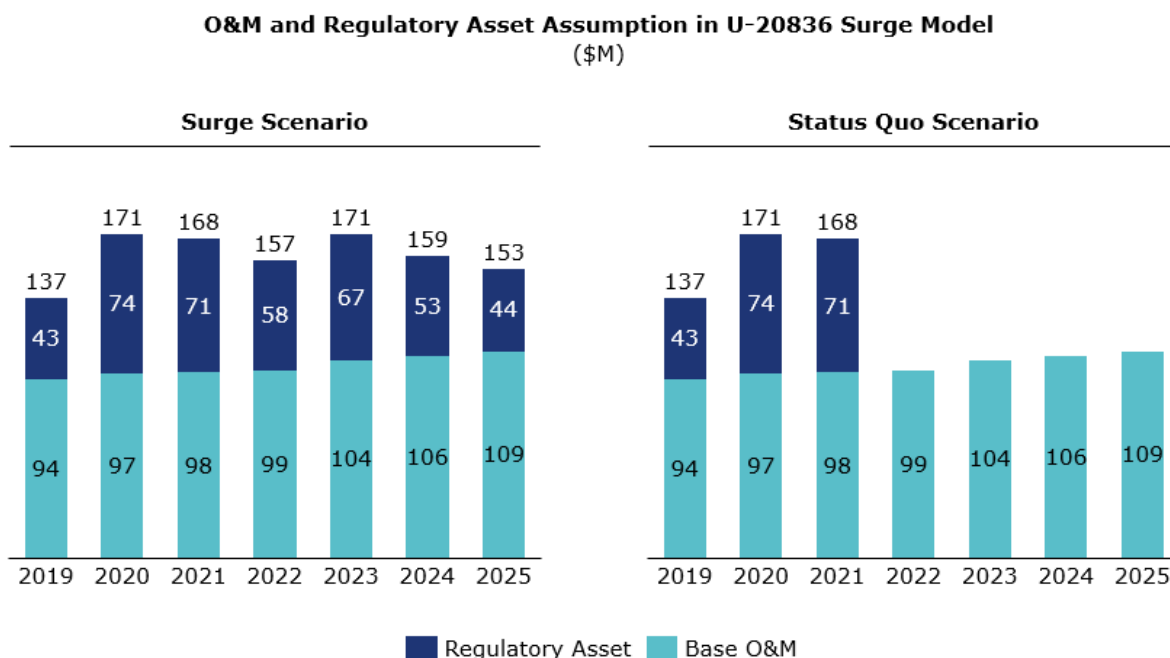
17 **Q14. When was U-21534 Exhibit A-22 last updated?**

18 A14. Exhibit A-22 was updated for Case No. U-20836 to justify the continued support
19 of the Surge program beyond 2021. Since the Company had already received
20 approval for the regulatory asset for 2019-2021, this version of the model compared
21 the relative difference in continuing the Surge for 2022 onward compared to
22 discontinuing the Surge at the end of 2021. Figure 1 shows the annual funding
23 assumptions used in the model and how the divergence takes place in 2022.

Line
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1

Figure 1 Base O&M and Regulatory Asset Assumption in U-20836



2

3 **Q15. Can the data provided in Exhibit A-22 be used to calculate the relative savings**
4 **from the Tree Trim Surge model?**

5 A15. Yes – the model projects the expected emergent capital costs for both the Surge and
6 Status Quo scenarios. Using the projected costs under the Surge scenario, the
7 Company could calculate an expected reduction in emergent capital relative to the
8 historic year of 2022.

9

10 **Q16. Using this methodology, what would be the projected emergent capital cost**
11 **savings for 2024 and 2025?**

12 A16. The cost savings would be \$22.8 million in 2024 and \$30.1 million in 2025. Please
13 refer to Exhibit A-42, Schedule GG1 for the detailed walk of this calculation.

Line
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1 **Q17. How does this compare to the cost savings the Company used (\$20.8 million**
2 **for 2024 and \$21.4 million in 2025)?**

3 A17. The Tree Trim model shows about \$11 million more in savings. The difference in
4 the projected savings is due to the models using different baselines and the
5 reliability model accounting for the system degradation. The Tree Trim Model
6 Surge used a baseline of 2018-2020. The Reliability Model used a baseline of 2018-
7 2022 to account for more recent actuals.

8

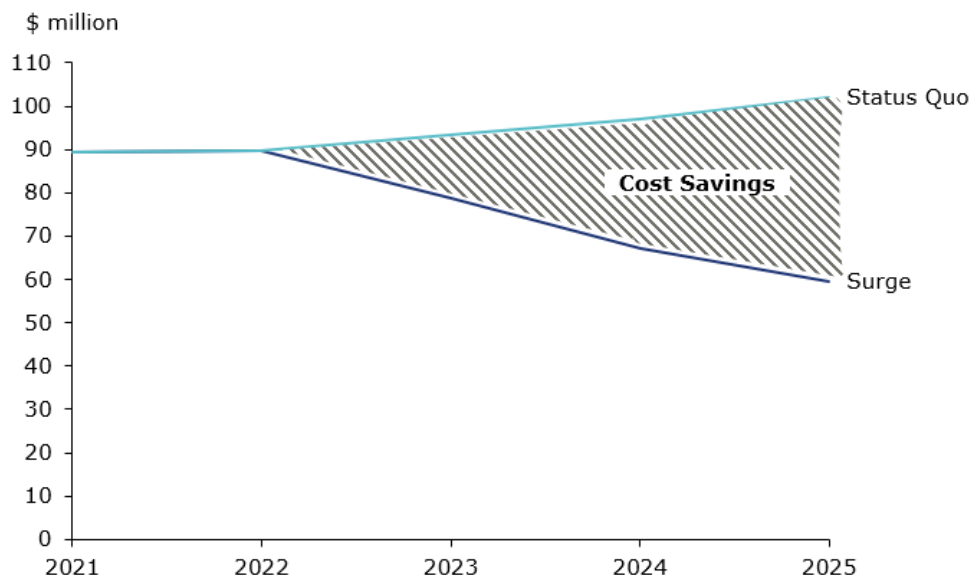
9 **Q18. Do you agree with using the emergent savings as they were provided in Exhibit**
10 **A-12?**

11 A18. Yes – based on the discussion above, Exhibit A-12 appropriately accounts for the
12 emergent capital savings arising from the Tree Trim program using the most
13 accurate and current data available.

14

15 **Q19. How does Witness Coppola determine the recommended emergent capital**
16 **disallowance?**

17 A19. Witness Coppola uses a discovery response from the Company in which the request
18 is to compare the relative cost savings between the Surge Scenario and Status Quo
19 Scenario in Exhibit A-22. Figure 2 provides a visual representation of these cost
20 savings. In this approach, the cost savings is the relative reduction the Company
21 forecasted by continuing the Surge from 2022 through 2025 compared to a status
22 quo scenario in which the Surge stopped at the end of 2021.



11
12 Witness Coppola requested this methodology in discovery, the Company
13 inadvertently provided the wrong data in its discovery response named AGDE-
14 4.167, provided in Exhibit A-42, schedule GG3. The question in which the mistake
15 occurred was used by Witness Coppola to make his recommendation on page 33,

Line
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1 line 13 through 19, and due to this error on Company's part, the dollar amounts
2 Witness Coppola provided are wrong. The discovery question from the AG
3 requested an update to a discovery request from multiple prior rate cases. The
4 Company has submitted a supplemental response to AGDE-4.167, with the correct
5 cost savings of continuing the Surge compared a scenario in which the Surge was
6 terminated at the end of 2021.

7

8 **Q21. Does Witness Coppola recommend additional capital disallowances related to**
9 **the Company's Tree Trimming activities?**

10 A21. Yes – Witness Coppola recommends disallowing \$6.9 million of capital investment
11 related to the development of the Tree Trim Risk Prioritization Model.

12

13 **Q22. What is the Tree Trim Risk Prioritization model?**

14 A22. The Company developed a risk prioritization model that leverages remote sensing
15 data (e.g., LiDAR), advanced analytics, and machine learning to estimate the
16 probability of vegetation-driven failures and determine optimal trim cycles for an
17 area. This model would enable the Company to use risk-based cycles for
18 maintenance trimming rather than a fixed-year cycle, thus optimizing tree trimming
19 based on specific vegetation characteristics that differ across areas of the
20 Company's service territory. Further discussion of the benefits of the risk-based
21 cycles can be found in my direct testimony beginning on page 28.

22

23 **Q23. Why does Witness Coppola recommend disallowing this investment?**

24 A23. Witness Coppola stated the following on page 73, line 1-5.

25 *"I recommend that the Commission remove the \$3,078,000 in capital*
26 *expenditures for 2022 and the \$3,824,000 for 2023 pertaining to the*

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1 *Tree Trim Risk Prioritization model because the Company did not*
2 *perform a cost/benefit analysis and did not justify that the model and*
3 *related expenditures are economically beneficial to customers.”*
4

5 **Q24. Did the Company perform a cost/benefit analysis for the model?**

6 A24. Yes, in Case No U-21297 the Company performed this analysis and included it as
7 Exhibit A-22, Schedule L2. I have included that analysis with my rebuttal
8 testimony as Exhibit A-42, Schedule GG2.
9

10 **Q25. What was the result of this analysis?**

11 A25. The discounted cash flow NPV for the risk prioritization model was \$11.2 million.
12

13 **Q26. Did Witness Coppola provide commentary or recommendations on this**
14 **investment in the Company’s 2023 rate case, U-21297?**

15 A26. No.
16

17 **Q27. Do you agree with the recommendation to disallow this investment as part of**
18 **this case?**

19 A27. No – for several reasons.

20 1. The capital costs for the Tree Trim Risk Prioritization model were included
21 in the prior case (Case No. U-21297) and not disputed by any party nor
22 disallowed by the Commission. The Company has already spent this capital
23 and has the functional model that we’re using.
24

25 2. The Company performed the cost/benefit analysis and requested these funds
26 in the last case and demonstrated a positive NPV for the tool.

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1 3. Furthermore, the idea of variable cycles was raised by intervenors and the
2 Commission in Case No. U-20836. In Case U-20836 (page 487), the
3 Commission ordered the Company to continue to explore efficiency
4 improvements, and benefits from a variable cycle for the tree trimming
5 program. In turn, the Company has complied with that directive by
6 developing the model.

7

8 Regulatory Asset Disallowances

9 **Q28. What is Witness Coppola's recommendation regarding the Company's**
10 **requested incremental regulatory asset request for 2025?**

11 A28. Witness Coppola recommends the Commission reject the request for an additional
12 \$87 million in deferred costs in 2025 for the Surge program.

13

14 **Q29. How does Witness Coppola justify this recommendation?**

15 A29. He provides a variety of reasons summarized below:

- 16 • The Company has not demonstrated the effectiveness of the Tree Trim
17 Surge (page 68, line 7 through page 69, line 2),
- 18 • The Company mischaracterizes the investment already made in the Tree
19 Trim Surge (page 67, line 6-12),
- 20 • The Company should have known and escalated the need for incremental
21 funding prior to this case (page 69, line 3 through 10),
- 22 • The justification for the specific components that lead to the need for more
23 funding was not sufficient (specifically the Company's payments of
24 outsource premiums (page 69, line 11 through page 70, line 4), investment

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1 in the Detroit Tree Trim Academy (page 70, line 8-19), and the impact of
2 tree removals on costs (page 71, line 1 through 10)).

3

4 **Q30. Does the Company believe the Tree Trim Surge has been effective in providing**
5 **reliability benefits?**

6 A30. Yes. As demonstrated in the Tree Trimming Surge Effectiveness section of my
7 direct testimony (beginning on page 8), circuits that have been trimmed to the ETPP
8 specification experience a significant improvement in reliability compared to the
9 circuits off-cycle and not yet trimmed as part of the Surge program.

10

11 **Q31. Witness Coppola points to the severe storm and other large weather events of**
12 **2023 as the test for measuring whether the increased tree trimming is making**
13 **a difference (page 68, line 7 through page 69, line 2). Do you agree that 2023**
14 **should be used as the test for the Surge's effectiveness?**

15 A31. No. When the Company measures the effectiveness of the Tree Trim program,
16 weather is normalized to account for variability in year-to-year events. This annual
17 variability was exacerbated in 2023 when the Company experienced five
18 catastrophic storms, including the most damaging winter ice storm in Company
19 history, and another summer catastrophic storm event that included heavy damage
20 from a historic six tornadoes.

21

22 The 2023 winter ice storm was especially challenging from a tree damage
23 perspective. The ice was almost ¾ inches thick in many areas and the weight of the
24 ice severely damaged trees, wires, equipment, and poles. This type of weather
25 phenomena causes significant damage to healthy trees that would not fail under

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1 typical weather events. Company Witness Hill discusses the severity of the 2023
2 weather events in further detail in his direct testimony, including pictures of large
3 trees that failed due to the ice (page 11).

4

5 **Q32. Do you agree with Witness Coppola's statement that the Company has**
6 **invested \$496 million in capital programs related to Tree Trimming, therefore,**
7 **the total cost of the Surge should be considered upwards for \$1.9 billion?**

8 A32. No, I do not agree for two reasons. First, the Company did not recognize the \$496
9 million as dollars associated with the Surge. When asked in discovery, Witness
10 Coppola explained it is the total capital costs related to Tree Trim that occurs as
11 part of emergent capital (Exhibit A-22, line 27).

12

13 **Q33. What is included in those capital costs?**

14 A33. The capital costs are related to emergent work, broken up into three categories.

Cost Category	Description	Total Provided by AG in Discovery DEAG-2 ¹	Exhibit A-22 Line Number
Tree Trim Reactive Capital	Trimming related to emergent events (non-Storm)	\$12.3	24
Tree Trim Storm Capital	Trimming related to restoring customers during storms	\$112.6	25
Other DO Tree- related Capital	Overhead (linemen) labor and equipment costs of restoring tree related outages	\$371.2	26

15

16 Most of the costs are "Other DO Tree-related capital" which reflect the cost for
17 lineman and field personnel to restore outages caused by trees. Those dollars are

¹ See Exhibit A-42 Schedule GG5 - DEAG-2

Line
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1 not associated with trimming trees. The costs associated with trimming trees are
2 reflected in “Tree Trim Reactive Capital” and “Tree Trim Storm Capital” and are
3 specific to restoring customers and/or mitigating hazards. Crews are not trimming
4 to the maintenance specification and therefore these costs do not drive progress to
5 completing the Surge.

6

7 **Q34. What is the second reason including the \$496 million is not appropriate?**

8 A34. Capitalized tree trimming costs have appropriately never been included in the Tree
9 Trim Surge program. Tree trimming that is capitalized is performed to support
10 construction projects such as 4.8kV hardening, Pole and Pole Top Management and
11 Modernization (PTMM), 4.8kV conversions, and distribution automation.

12

13 **Q35. Why does Witness Coppola believe that the Company should have known the**
14 **cost of the Surge was higher prior to 2023?**

15 A35. Witness Coppola uses the data provided in discovery response AGDE-4.159d to
16 demonstrate that the Company’s cost per mile for reclaiming circuits (trimming to
17 the ETTP specification for the first time) increased by 41% between 2021 and 2022,
18 suggesting the Company should have had indications that tree trimming was
19 costing more than planned.

20

21 **Q36. Do you agree that the 2022 reclaim costs should have been used as an**
22 **indication of funding challenges?**

23 A36. No, the average cost per mile by itself for any given year is an incomplete picture,
24 because that average can vary year-to-year based on the volume of work required
25 by the unique vegetation characteristics of each specific circuit. In 2022, the cost

Line
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of reclaim circuit miles was high because of the areas in which we focused our trimming. In 2022, the Company prioritized several key communities that were significantly off-cycle compared to our system average. These communities were also ones significantly impacted for the 2021 weather events and the Company recognized the need to focus reclaiming these areas to improve reliability for those impacted customers.

The tree work in these areas was more dense and intensive, therefore expensive than in years past and drove up the overall average for 2022. The average cost for reclaim circuits reduced by 20% in 2023, validating that 2022 was an outlier.

Table 1 Average cost per mile of reclaim miles

	2019	2020	2021	2022	2023
Distribution Reclaim \$/Mile	\$ 29,403	\$ 29,375	\$ 28,507	\$ 43,695	\$ 35,086

Q37. Does Witness Coppola raise specific concerns with the cost drivers that have impacted the Surge?

A37. Yes, he raises issues with the Company's practice of securing outsource crews through paying premiums, investments made in the Detroit Tree Trim academy and the gap in actual tree removals.

Q38. What is the outsource premium?

A38. The outsource premium refers to dollars the Company has paid to attract and retain outsource tree trimming crews. Specifically, these payments are a daily per diem and overtime.

Line
No.

1 **Q39. What is an outsource trimmer?**

2 A39. An outsource trimmer is not a local resident of our service territory. These trimmers
3 travel across the country, performing utility line clearance on different properties.
4 While on DTE Electric's property, the Company has paid a competitive per diem
5 to retain the necessary workforce for the Surge. In addition, the Company has
6 offered 60-hour work weeks for maintenance trimming (20-hours of overtime).
7 This schedule is attractive to outsource trimmers as they are interested in
8 maximizing the workweek as they do not have a family or permanent residence in
9 the area.

10

11 **Q40. Why are outsource trimmers necessary?**

12 A40. Supplementing our local workforce with outsource crews was necessary to quickly
13 ramp up the trimming resources when the Surge was approved in 2019. The tree
14 trim budget increased by over 50% from 2018 to 2019. To train a fully qualified
15 line clearance tree trimmer takes multiple years. Further, the workforce has been in
16 high demand across the county as many utilities are increasing their vegetation
17 management programs. Leveraging outsource trimmers has also allowed the
18 Company to modify workforce year-to-year as the funding levels of the Surge have
19 fluctuated.

20

21 **Q41. In Case No. U-20162, did the Company account for needing outsource**
22 **trimmers?**

23 A41. Yes, the Company anticipated needing to ramp up the trimming workforce quickly
24 to meet the commitments of the Surge and included costs associated with paying
25 the outsource premium as part of the forecasted cost of the Surge.

Line
No.

1 **Q42. Has the actual outsource premium exceeded the forecast?**

2 A42. Yes, the Company anticipates paying \$69 million more in outsource premiums than
3 forecasted in Case No. U-20162 for the full length of the Surge.
4

5 **Q43. Why have actuals exceeded forecast?**

6 A43. The Company has required more outsource trimmers than anticipated – driven
7 predominately by the local workforce not growing at the expected rate. The slow
8 local-workforce growth can be attributed to disruption created by the COVID-19
9 pandemic. Many workforce development efforts were paused in 2020 due to the
10 pandemic creating a hole in the woodsmen pipeline. Further, the dynamic of the job
11 market shifted coming out of the pandemic, meaning individuals seeking entry-
12 level jobs had many opportunities, especially if they had a CDL (Commercial
13 Driver's License), a required credential for trimmers on DTE's property.
14

15 **Q44. What commentary does Witness Coppola provide around the outsource
16 premium?**

17 A44. Witness Coppola suggests the Company should take corrective actions against
18 paying our current four contractors the outsource premiums and eliminate these
19 costs in 2024 and 2025 (page 70, line 1-4).
20

21 **Q45. Do you agree with this characterization?**

22 A45. No, the number of contractors does not drive the amount of outsource premiums
23 paid; it is driven by the number of outsource trimmers we have on property². The
24 Company has had on average 390 outsource trimmers on property to support the

² With respect to the tree trimming workforce, the term "on property" means a full time equivalent largely dedicated to work on behalf of the Company.

Line
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1 Tree Trim Surge. The per diem is a direct pass through to the outsource trimmers,
2 and the overtime premium is reflective of the Local-17 wage structure we pay to all
3 our trimmers.

4

5 **Q46. Do you agree with Witness Coppola's recommendation that the Company**
6 **needs to take corrective actions to mitigate/eliminated the costs for 2024 and**
7 **2025?**

8 A46. No, while the Company will continue to look for solutions that can lower the cost
9 of tree trimming, if the Company were to stop paying these premiums mid-way
10 through 2024 and continue to do so into 2025, we would significantly jeopardize
11 the completion of the Surge.

12

13 **Q47. Has the Company taken action to support development of the local workforce?**

14 A47. The Company is participating in three programs in an effort to increase the number
15 of local trimmers. The three programs are the IBEW Local 17 Traditional Boot
16 Camp, the Parnall Correctional Facility Vocational Village Training Program, and
17 the City of Detroit Tree Trim Academy.

18

19 1. Traditional Boot Camp – IBEW holds regularly scheduled boot camp training
20 for apprentices. Camps are conducted at their training facility in Wales, MI.

21 2. Parnall Correctional Facility – The Parnall Tree Trimming program is designed
22 to provide returning citizens the skills needed to start as an apprentice tree
23 trimmer. DTE has partnered with the Michigan Department of Corrections to
24 provide qualified instructors and the required training support within the prison
25 facility before participants are released.

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1 3. Tree Trim Academy – The Company has partnered with the City of Detroit,
2 IBEW Local 17, and its tree-trimming contractors to develop and implement a
3 pre-woodsman training program to satisfy the demand for qualified tree
4 trimmers. The tree trimming academy is located within the City of Detroit and
5 facilitates training that is aimed at preparing local resident candidates to work
6 as woodsmen. Once candidates complete the pre-woodsman program,
7 graduates enter the traditional IBEW boot camp.

8

9 **Q48. How much has the Company invested in the Detroit Tree Trim Academy?**

10 A48. The Company will have invested \$4.3 million in the Detroit Tree Trim Academy
11 through the course of the Surge (2019-2025).

12

13 **Q49. Does Witness Coppola support the Company's investment in the Detroit Tree**
14 **Trim Academy?**

15 A49. No, Witness Coppola miscalculates the retention rate for the program as 33% and
16 then inappropriately concludes it should not be considered a success (page 70, line
17 14). "The Company should look at either significantly restructuring the program to
18 at least double the retention rate or, if that goal is not achievable, shut down the
19 academy and reassign those dollars to hiring trained tree trimmers or not spend
20 them at all." (Coppola direct, page 70, line 16-19)

21

22 **Q50. What is the correct retention rate for the Academy?**

23 A50. Since 2021, 56% of the students who have been placed with a tree contractor
24 continue to work as tree trimmers on property. This is the number of trimmers still

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1 with a tree vendor divided by the number of candidates originally placed with a tree
2 vendor.

3

4 **Q51. Should this retention rate be seen as a success?**

5 A51. Yes, absolutely. Historically, only 30% of trimmers who began the traditional
6 bootcamp successfully progressed through the full apprenticeship. Academy
7 graduates who were placed on property are almost twice as likely to continue
8 through the apprenticeship, compared to candidates who do not participate in the
9 Academy.

10

11 **Q52. Are there other benefits from the Tree Trim Academy?**

12 A52. Yes, along with growing the local workforce, the Academy was developed in
13 Detroit to increase diversity in the tree trimming workforce *and* provide career
14 opportunities to the local community. Of the graduates, 71% are people of color
15 and 36% are Detroit residents.

16

17 **Q53. How much does the Company plan to invest in the Tree Trim Academy in**
18 **2025?**

19 A53. The Company plans to continue with an annual investment of ~\$700k in 2025.
20 Witness Coppola misstates the planned investment for 2025, arguing against “the
21 *additional* \$4.1 million that the Company wants to allocate to it in 2025.” (Coppola
22 direct testimony, page 70, lines 15–16) The Company provided the annual
23 investments in the Academy, including the forecasted amount for 2025 in discovery
24 response AGDE-4. The Company is providing that response as Exhibit A-42 Sch
25 GG4. It shows a *total* spend for 2025 of approximately \$700k, not \$4.1 million,

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1 and a cost for the period of 2019 through 2025 of \$4.3 million. The dollars spent
2 on this Academy benefits the Company, its customers, and their communities.

3

4 **Q54. What does Witness Coppola say with respect to the Company's historical**
5 **removal rates?**

6 A54. In addition to trimming trees, the Company targets removing some trees within our
7 right-of-way as part of the maintenance trimming program. Witness Coppola raises
8 concerns with the Company's annual removal rate targeted vs actual being between
9 38%-48%. Targeted trees are defined as a good removal candidate, based on the
10 Company's trimming specification which prioritizes removing smaller, faster
11 growing trees.

12

13 **Q55. Why is the Company not removing more trees that are good removal**
14 **candidates?**

15 A55. To remove a tree, a customer must provide signed permission. The Company
16 currently will make multiple attempts to contact customers/property owners to
17 discuss and obtain signed permits. The Company is committed to achieving the
18 necessary line clearances to ensure safety and improvement in reliability for
19 customers. While this commitment requires that the Company obtain the necessary
20 clearances through trimming, removing trees provides additional benefits in terms
21 of reliability and future costs, however, the impact and pushback from some
22 customers can be significant. To that end, the Company is currently examining a
23 more progressive approach to remove trees that are deemed hazardous to the safety
24 and reliability of the circuits. This is an area where Commission's support will be
25 very beneficial to improving the safety and reliability/resiliency of the grid,

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1 especially considering the more frequent extreme weather conditions we are
2 experiencing.

3

4 **Q56. Do you believe the requested \$87 million in regulatory asset is a prudent and**
5 **justified request?**

6 A56. Yes, the Company has performed extensive analysis to understand the drivers for
7 the gap in funding the Tree Trim Surge and closed the majority of the shortfall
8 without requesting incremental support. The requested \$87 million is essential to
9 both complete the Surge *and* keep on-cycle miles trimmed and maintained.

10

11 O&M Disallowances

12 **Q57. What is Witness Coppola's recommendation with regards to accounting for**
13 **Tree Trim Surge Savings with respect to O&M emergent savings?**

14 A57. On page 106, line 6 through 7 of Witness Coppola direct testimony it is
15 recommended the Commission remove \$8.8 million in cost savings from the
16 Company's forecasted O&M expense due to savings by the Tree Trim Surge
17 program.

18

19 **Q58. Does the Company agree that the Tree Trim Surge will result in O&M**
20 **savings?**

21 A58. Yes.

22

23 **Q59. Does the Company agree with the \$8.8 million O&M reduction proposed by**
24 **Witness Coppola?**

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A59. No. Based on Witness Coppola's Exhibit AG-40, the \$8.8M is the net difference of the total calculated O&M savings (\$17.6 million) and what was already included in Exhibit A-13, Schedule C 5.6 (\$8.8 million).

That \$8.8 million difference represents the cost savings for the Tree Trim Reactive line item. These costs are included in Exhibit A-22, Schedule L1, line 4 and therefore the savings between the historical year and the projected test period are already accounted for. The table below summarizes how the total O&M cost savings were calculated and where those savings are realized.

Table 2 O&M Savings

Cost Category	O&M Savings (million)	Where are savings accounted for?
Tree Trim Reactive	\$8.8	Savings are realized as part of the Tree Trim Surge budget and reflected in Exhibit A-22, Schedule L1
Tree Trim Storm	\$5.0	Savings are realized outside of the Tree Trim Surge budget and reflected in Exhibit A-13, Schedule C 5.6
Other DO-Service Operations	\$3.8	
Total	\$17.6	

Part 2 – Recommendations made by AG-MN Witness Alvarez and CUB-MN

Witness Denzler

Q60. What recommendations does AG-MN Witness Alvarez provide related to the Tree Trim program?

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1 A60. Witness Alvarez recommends the Commission include the following items in their
2 decision for this case (page 8, line 13-21):

- 3 • Order an audit of the Company's rights-of-way every 5-years
4 • Require the Company to identify the extent it has capitalized tree trimming
5 costs in PTMM, 4.8kV Hardening, 4.8kV Conversions and Distribution
6 Automation

7
8 **Q61. Why does Witness Alvarez recommend the rights-of-way audit?**

9 A61. He believes the audit is necessary to ensure the Company adheres to vegetation
10 management moving forward and does not fall off-cycle. (Alvarez direct, page 42,
11 line 12 through page 43, line 10)

12

13 **Q62. Does the Company agree that the audit is necessary?**

14 A62. No. Paying for a third-party audit of the Company's rights-of-way is redundant to
15 existing activities, which are more cost-effective and timely ways for the
16 Commission and others to monitor the Company's future commitments to and
17 progress on maintaining the tree trimming program.

18

19 **Q63. Can you elaborate on the existing activities?**

20 A63. Yes.

21 The Company performs 100% inspection audits of the miles trimmed each year to
22 ensure we are obtaining the necessary clearances. Details of the inspection process
23 are included in my direct testimony on page 34, beginning line 11.

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1 The Company supports the continued submission of the Tree Trim annual report –
2 which provides a summary of the miles trimmed and dollars invested in tree
3 trimming each year.

4 The Company also submits monthly data as part of the requested reliability data to
5 Staff – this information provides insight into the Company’s tree trimming progress
6 against the annual maintenance plan.

7

8 **Q64. Witness Alvarez suggests that the Company should be required to provide**
9 **information about the capitalization of tree trimming costs. (Alvarez direct,**
10 **page 38, lines 14 – 15) Has the Company provided this type of data in the past?**

11 A64. The Company provides the capitalization costs associated with 4.8kV Hardening,
12 which is the majority of tree trim capitalization costs, in the Tree Trim Annual
13 Report that is included as an exhibit in this case.

14

15 **Q65. Are there additional recommendations regarding Tree Trim from other MN**
16 **witnesses?**

17 A65. Yes. CUB-MN Witness Denzler recommends the Commission require the
18 Company to perform an audit/review of the Tree Trim Prioritization model to
19 measure its accuracy and compare it to alternative models offered by third parties.

20

21 **Q66. Does the Company believe it is necessary to compare the prioritization model**
22 **to alternative, third party models?**

23 A66. No, the Company has already invested in the current model, and as discussed
24 earlier, believes it will provide positive benefits to customers. The Company does
25 not see it as prudent to invest in additional tools at this time.

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1 Instead, the Company is prioritizing using and testing the existing model to defer a
2 subset of miles due for trimming based on a five-year cycle. The Company will
3 perform both field- and data-based reviews of how these deferred circuits
4 performed from a reliability and future cost to trim perspective.

5

6 **Part 3 – Rebuttal to testimony by Ann Arbor Witnesses**

7 **Q67. Does Witness Giacobazzi raise any concerning topics related to the tree trim**
8 **program?**

9 A67. Indirectly yes – Witness Giacobazzi discusses the impact of underground methane
10 leaks on trees (page 7, line 8-15). Witness Giacobazzi seems to suggest an
11 expectation that the Company’s tree trimmers should be noting tree damage specific
12 to methane leaks and reporting it to the City of Ann Arbor.

13

14 **Q68. Do you believe tree trimmers should be expected to report potential methane**
15 **leaks?**

16 A68. No, this expectation is beyond the scope of training provided in the Tree Trimming
17 program, and to include this type of identification into our maintenance program
18 would require additional training and process development. The Company does not
19 consider this to be a prudent expectation of a program focused on ensuring the safe
20 and efficient clearing of vegetation from around our overhead infrastructure.

21

22 **Part 4 – Concluding Commentary**

23 **Q69. Are there any final themes that emerged in intervenor testimony that you**
24 **would like to address?**

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1 A69. Yes, witnesses for both Ann Arbor and AG-MN implied that the Company neglects
2 its tree trimming efforts.³

3

4 **Q70. Do you agree?**

5 A70. No, since the beginning of the Surge, the Company has demonstrated its
6 commitment to the Surge and the importance of tree trimming. At the end of 2023,
7 our system was 83% on-cycle, and the city of Ann Arbor was 95% on-cycle.
8 Further, the Company has demonstrated additional commitment for the program by
9 providing incremental funding, i.e., the incremental \$90 million in 2022/2023.

10

11 **Q71. Is there other witness testimony you would like to address?**

12 A71. Yes, AG-MN Witness Alvarez states “DTE admits that more frequent tree
13 trimming – for the most part an O&M expense, not capital spending – is the most
14 effective thing DTE can do to improve reliability, stating ‘in areas where tree
15 trimming has been completed, communities have experienced, on average, 60%
16 fewer outages.’” Page 16, line 7 through page 17, line 1.

17

18 **Q72. Do you agree with this statement?**

19 A72. No, I find three mischaracterizations in this statement. The first is that achieving
20 our reliability goals and ensuring safe, reliable service for our customers requires
21 that the Company to take a holistic, multipronged approach to improving our grid.
22 Trimming trees and vegetation, and maintaining our rights-of-way is an important
23 piece, but as supported by witness Kryscynski in his rebuttal testimony beginning
24 on page 7, are not the only investments the Company need to make. Trimming the

³ Ann Arbor Witness Stults page 19, line 1-4; AG-MN Witness Alvarez page 42, lines 18 – 19:

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1 trees will not change the age or condition of our equipment – that requires robust
2 capital investments.

3

4 **Q73. What are the other two mischaracterizations by Witness Alvarez?**

5 A73. It is unclear the exact source of the “more frequent” statement, however, I would
6 like to clarify that the Company believes regular, on-cycle maintenance trimming
7 is critical to the Tree Trim program. Generally, we believe this means a five-year
8 cycle with the opportunity to adjust circuits as we continue to leverage the Tree
9 Trim Prioritization model to move to an optimized, variable-cycle.

10

11 Finally, Witness Alvarez generalizes the 60% improvement statistic to downplay
12 the improvements from strategic capital programs. As discussed in my direct
13 testimony, the Company looks at the effectiveness of the Tree Trimming program
14 specific to *tree-related* events. The most recent effectiveness data demonstrates
15 circuits trimmed to the ETPP specification experience 58% fewer *tree-related*
16 customer interruptions (RCS 11, line 9) relative to circuits not trimmed to the ETPP
17 specification. Further details on the tree trim effectiveness methodology can be
18 found on RCS 8 Line 13 through RCS 9 line 5.

19

20 **Q74. Does this conclude your rebuttal testimony?**

21 A74. 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-21534

REBUTTAL TESTIMONY

OF

THERESA M. UZENSKI

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF THERESA M. UZENSKI

Line
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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Theresa M. Uzenski (she/her/hers). I am employed by DTE Energy
4 Corporate Services, LLC, a subsidiary of DTE Energy Company (DTE Energy).
5 My business address is One Energy Plaza, Detroit, MI 48226.

6
7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.
10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to refute certain positions taken by the
14 other parties as follows. The absence of a discussion of other matters in my
15 testimony should not be taken as an indication that I agree with all other aspects of
16 intervenor testimony. More specifically, I provide rebuttal on the following topics:

17 • Michigan Public Service Commission (MPSC or Commission) Staff's (Staff)
18 adjustment to remove IT O&M costs associated with disallowed Level 2
19 programs in the amount of \$2.4 million is too high because it represents 100% of
20 the cost instead of DTE Electric's portion of a shared expense between DTE
21 Electric and other DTE affiliates.

22 • If shared asset capital projects (i.e., projects that are to be utilized by more than
23 one DTE Energy company) are disallowed by the Commission, then the related
24 shared asset revenue included in projected net operating income must be
25 reduced for the amounts that will not be billed to affiliated entities.

Line
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- 1 • Staff's disallowance of fleet vehicle capital expenditures should be rejected
- 2 because it was based on a misunderstanding of the total amount of expense and
- 3 utilization of only a portion of that total expense.
- 4 • The Attorney General's (AG) proposed disallowance of the vehicle fleet capital
- 5 expenditures should be rejected because the Company's forecast method is
- 6 more accurate than the use of a historical average proposed by the AG.
- 7 • The AG's proposed disallowance of office space updates and equipment should
- 8 be rejected because it disregards the Company's reasonable explanation and
- 9 support for the expenditures provided in discovery.
- 10 • Any disallowances of capital projects going in-service beyond the projected test
- 11 period should not have an impact on the revenue requirement because the cost
- 12 is offset by an AFUDC credit in projected net operating income and that alone
- 13 is not a reasonable basis to disallow capital project expense.
- 14 • The AG's proposed exclusion of the Ludington regulatory asset should be
- 15 rejected because the regulatory asset has been approved by the Commission to
- 16 address circumstances at an important generation asset.
- 17 • The AG's proposal to remove the \$3.9 million regulatory asset for Deferred
- 18 Incentive Compensation and replace it with a regulatory liability of \$6.8 million
- 19 should be rejected because the calculation is inaccurate and inconsistent with
- 20 the design of the approved mechanism. My testimony supports the correct
- 21 calculations based on actual 2022 and 2023 costs.
- 22 • Staff's proposed adjustments to certain benefits expenses based on the net
- 23 expense recorded in 2023 is incorrect. I support that the 2023 expenses should
- 24 be increased to reflect a normalized allocation of costs.

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- 1 • The proposal by AG-MNSC (Michigan Environmental Council, Natural
2 Resource Defense Council, Sierra Club, and Citizens Utility Board of
3 Michigan) to require DTE Electric to continue to explain its decision to
4 capitalize tree trimming expenses in its next rate case should be rejected. The
5 Company has previously explained its policy, and my rebuttal testimony
6 confirms that the Company complies with the accounting prescribed by the
7 Uniform System of Accounts (USoA).

8

9 **Q4. Are you sponsoring any exhibits in this proceeding?**

10 A4. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-37	BB1	Shared Asset Adjustment and O&M for Proposed
		Disallowances
A-37	BB2	Projected Fleet Vehicle Purchases 2025
A-37	BB3	Incentive Plan Metrics

16

17 **Q5. Were these exhibits prepared by you or under your direction?**

18 A5. In general, yes, they were. However, Exhibit A-37 Schedule BB3 is copy of the
19 Company's 2021 Case No. U-20836 incentive compensation performance
20 gradients sponsored by Witness Cooper in that case.

21

22 **IT O&M**

23 **Q6. What O&M disallowance did Staff propose related to IT capital projects that**
24 **they propose be disallowed?**

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1 A6. Staff has reduced O&M by \$2.4 million related to IT capital projects that it proposes
2 be disallowed. Staff Witness Rogers explains this on page 6 of her direct testimony,
3 starting at line 6.

4
5 **Q7. Do you agree with these adjustments?**

6 A7. Company Witnesses Sharma and Hatsios address the prudence of the specific
7 projects. However, should the Commission decide to disallow the projects and
8 related O&M, then the O&M impact must be reduced by the amount not applicable
9 to DTE Electric. The \$2.4 million O&M cited by Staff is the amount supporting
10 all DTE Energy users of the assets. The actual IT O&M costs recorded at DTE
11 Electric are based on the bill down of costs from the DTE Energy Corporate
12 Services LLC, approximately 74% of the total, or \$1.8 million of the total \$2.4
13 million. Therefore, the portion of the O&M costs not related to DTE Electric is
14 \$0.6 million as shown on Rebuttal Exhibit A-37, Schedule BB1, line 18 column
15 (g).

16 **Revenue**

17 **Q8. What did the Company forecast for Shared Asset revenue?**

18 A8. As shown on my Exhibit A-13, Schedule C3, line 14, the Company forecasted \$63.5
19 million of revenue from shared assets such as building and information technology
20 with its affiliates. The assets are reflected in rate base for DTE Electric, but the
21 revenue requirement is reduced by the amount billed to DTE Energy affiliates for
22 their usage of the assets.

23
24 **Q9. What is the impact to Shared Asset revenue if the Commission disallows the**
25 **underlying assets?**

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1 A9. Since the projected revenue assumes the capital projects supported in the instant
2 case are approved, the revenue projection needs to be reduced for the impact of any
3 capital disallowances of shared assets. The reduction to shared asset revenue for
4 each project proposed for disallowance is shown in my Rebuttal Exhibit A-37,
5 Schedule BB1, column (f), for a total of \$1.8 million on line 18. If the Commission
6 disallows a capital project that is for a shared asset, then it must also remove the
7 revenue related to that asset from projected net operating income.

8

9 **Capital Expenditures**

10 **Q10. What disallowances related to vehicle fleet capital expenditures have been**
11 **proposed by the AG?**

12 A10. AG Witness Coppola, at lines 7 to 12 on page 54 of his direct testimony, proposes
13 disallowances of \$4.564 million and \$8.187 million for 2024 and 2025 capital
14 expenditures, respectively. This is based on comparing the Company's filed
15 request to an average of expenditures during 2021 to 2023.

16

17 **Q11. How do you respond to the AG's methodology to estimate projected costs?**

18 A11. I disagree with the AG's methodology. AG Witness Coppola asserts on page 53,
19 starting at line 17, through page 54 line 3, that the Company did not provide data
20 on the types of vehicles expected to be purchased in 2025. This is not accurate.
21 The Company provided a list of vehicle and equipment purchases planned for 2025
22 in response to Staff discovery question 4.3d. A copy is provided in my Rebuttal
23 Exhibit A-37, Schedule BB2. This exhibit confirms that the Company has specific
24 vehicle purchases planned for 2025. As described in my direct testimony, the
25 Company uses a life-cycle model to optimize the total cost of ownership and

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1 develop a replacement strategy. This is a more reasonable forecast methodology
2 than the simplistic historical average used by Witness Coppola. Therefore, the
3 Commission should reject his proposed disallowances and approve the Company's
4 projected capital expenditures for vehicle fleet.

5

6 **Q12. Did Staff propose a disallowance of fleet capital expenditures?**

7 A12. Yes. Staff Witness Boutet proposed a disallowance of \$2.84 million for the bridge
8 period and \$3.83 million for the test year on page 7, starting at line 3 of his direct
9 testimony. He explains that the adjustment is "based on the historical
10 underspending in 2023 in this category as well as evidence that the Company is
11 again on track to underspend in 2024." Witness Boutet comes to this conclusion
12 based on the list of vehicles purchased by the Company in 2023 shown on his
13 Exhibit S-12.6, which is what the Company understood was being requested. Page
14 8 of his exhibit shows the direct cost of the vehicle purchases as \$29.3 million.
15 Witness Boutet compared this to the Company's 2023 projection of \$32.8 million
16 for Vehicle Fleet and Maintenance on my Exhibit A-12, Schedule B5.8, line 1,
17 column (c) and logically, but incorrectly, assumed that the Company underspent its
18 forecast.

19

20 However, the Company's discovery response to STDE-4.3a, shown on his Exhibit
21 A-12.6, reflected only the direct purchase cost of vehicles (which is what the
22 Company understood was being requested) and did not include capital maintenance
23 costs or the internal labor costs allocated and capitalized as part of the cost of the
24 Company's vehicle fleet. The total actual capital expenditure for 2023 for vehicle
25 fleet was \$33.2 million and was provided in response to AG discovery question

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1 AGDE-3.130a. (See AG Witness Coppola's Exhibit AG-17, page 2.) Thus, there
2 was no underspending in 2023. The Company's projection for 2024 provided in
3 STDE 4.3b, and shown on Witness Boutet's Exhibit S-12.7, reflects the same
4 circumstance. It did not include capital maintenance, or the internal labor related
5 to the capitalized fleet vehicles. The complete forecast for 2024 is \$38.2 million
6 and is also shown in AGDE-3.130a (Exhibit AG-17, page 2). I am requesting that
7 the Commission reject Witness Boutet's proposed disallowances which were
8 triggered solely by the incorrect exclusion of capital maintenance and labor cost
9 components in the Company's response to Staff discovery STDE-4.3.

10

11 **Q13. What is the Attorney General's proposed disallowance for floor renovation**
12 **capital projects?**

13 A13. Starting at line 13 on page 50 of his direct testimony, AG Witness Coppola proposes
14 disallowances of capital expenditures totaling \$14.3 million for office space
15 updates and office equipment. On page 51, at line 3, he asserts the Company did
16 not provide clear answers as to why the expenditures were needed.

17

18 **Q14. How do you respond to Witness Coppola's proposed disallowance?**

19 A14. I disagree – both with the disallowance as well as the conclusion that the Company
20 did not provide clear answers. Witness Coppola is disregarding the information the
21 Company provided, which is included in his Exhibit AG-16. As can be seen on
22 pages 2 through 5 of his exhibit, the Company explained the rationale for the costs.
23 The Company had reduced its total office space by selling buildings and
24 terminating leases and then had to increase the number of workstations within that
25 smaller space to accommodate employees returning to the office after the

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1 pandemic. We moved from 2,000 reservable workstations to 4,100 workstations
2 assigned to each employee. Additional technology was required to enable more
3 video conferencing for employees in the office with employees working remotely.
4 Equipment was added as needed and meeting space was optimized. The conversion
5 of the open space in the downtown Detroit headquarters lobby was to accommodate
6 large groups that previously used leased space or facilities the Company no longer
7 owns. Regardless of whether he agrees with the Company's decisions, Witness
8 Coppola's assertion that the Company did not explain the expenditures is not
9 accurate. The Company maintains that its decisions regarding floor renovation
10 capital projects were reasonable, prudent, and justified. Thus, the Commission
11 should reject the AG's proposed disallowances of \$6.3 million for 2023 and \$8.0
12 million for 2024 (page 52, line 6).

13

14 **Q15. Did any of the parties to this case propose a reduction in rate base for projects**
15 **not going in service during the projected test period?**

16 A15. Yes. The AG and Association of Businesses Advocating Tariff Equity (ABATE)
17 have proposed disallowances of projects that are not in service during the projected
18 test period.

19

20 **Q16. What impact should a disallowance of projects that do not go into service**
21 **during the projected test period have on the Company's requested rate relief?**

22 A16. Such disallowances should not have any impact. As discussed in my direct
23 testimony, AFUDC is added to the asset being constructed with a corresponding
24 credit to the income statement. Including the credit to income from AFUDC offsets
25 the impact of including CWIP in rate base and therefore, projects that do not go

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1 into service during the projected test period have no impact on the Company's
2 revenue requirement and deficiency. To ensure that is the result, either the
3 proposed disallowances for projects not going into service should be excluded from
4 any reductions to rate base approved by the Commission, or a corresponding
5 adjustment (reduction) in pre-tax AFUDC should be added to offset the removal of
6 the projects from approved rate base.

7

8 **Ludington Regulatory Asset**

9 **Q17. What is the Attorney General's recommended adjustment to working capital**
10 **related to deferred costs for the Ludington power generating facility?**

11 A17. On page 58, starting at line 7, AG Witness Coppola proposes that this regulatory
12 asset of \$9.9 million be removed from working capital until "the Commission
13 decides the appropriate amount of deferred costs that the Company should be
14 allowed to recover" because the dispute causing the costs is unsettled. He suggests
15 a return can then be "included with the deferred amount for the period of time the
16 recoverable portions of the net costs were outstanding."

17

18 **Q18. How do you respond to this proposed adjustment?**

19 A18. As will be detailed below, AG Witness Coppola has made a proposal that would
20 unreasonably take away the ability for the Company to cover, in a timely manner,
21 the financing costs related to costs incurred by the Company and recorded to a
22 regulatory asset that was approved for use by the Commission in Case No. U-21310
23 for costs necessary for the ongoing operation of a generation asset that is important
24 to the State of Michigan and a fundamental piece of clean energy advancement.

Line
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1 **Q19. How does AG Witness Coppola support the removal of the Ludington Plant**
2 **regulatory asset from working capital?**

3 A19. AG Witness Coppola indicates that there are still related replacement power issues
4 in Power Supply Cost Recovery (PSCR) cases that have not been resolved and the
5 litigation with Toshiba is also not resolved. Based on these unresolved issues, AG
6 Witness Coppola indicates that it is imperative that the Company not earn a return
7 on the deferred amounts until the Commission rules on the appropriate amount to
8 be recovered in rates.

9

10 **Q20. Do you agree that the reasons provided by AG Witness Coppola provide**
11 **sufficient justification to remove the Ludington Plant regulatory asset from**
12 **working capital?**

13 A20. I do not. AG Witness Coppola's proposal will require the Company to support the
14 financing of all costs incurred until final resolution in the Toshiba litigation. This
15 is not a reasonable proposition. Therefore, the Commission should reject the
16 recommendation to remove the balance from working capital.

17

18 **Q21. Is the Witness Coppola's position consistent with established practice for**
19 **regulatory assets?**

20 A21. No. It is not. Earning a return on a regulatory asset by including it in working
21 capital is an accepted regulatory practice and is consistent with the treatment of
22 other working capital financed by the Company. Regulatory assets are generally
23 included in working capital unless they have a separate recovery mechanism. None
24 of the costs recorded to the Ludington regulatory asset are being recovered in the
25 PSCR or other mechanism.

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1 **Q22. Does including costs associated with the Ludington repairs in the regulatory**
2 **asset and as working capital harm customers?**

3 A22. No, it does not. Requiring the utility to bear the financing costs during the pendency
4 of the litigation against Toshiba would be unfair and would hinder its ability to
5 accomplish the projects needed to remedy Toshiba's defects. The regulatory asset
6 ensures that the utility can accomplish the necessary work at the same time it is
7 prosecuting the lawsuit against Toshiba for the benefit of customers. Any costs
8 which are not ultimately recovered from Toshiba will be fully reviewed by the
9 Commission after the conclusion of the lawsuit. The regulatory asset, and the
10 accounting treatment used by the Company in this case is appropriate.

11

12 **Incentive Compensation Regulatory Asset**

13 **Q23. What is the Attorney General's recommended adjustment to working capital**
14 **related to deferred incentive compensation?**

15 A23. AG Witness Coppola discusses this starting at line15 on page 58 of his direct
16 testimony. The Company projected a balance of \$3.9 million in a regulatory asset,
17 representing the difference between the amount of incentive compensation related
18 to operating metrics approved in Case No. U-20836, and the forecasted expense
19 based on achieving the targeted results. Witness Coppola argues (1) there is no
20 recoverable balance for 2022, (2) the balance for 2023 is a regulatory liability of
21 \$6.8 million, and (3) it is premature to establish a regulatory asset for anticipated
22 results in 2024. He also argues, on page 61, line 15, that the liability balance should
23 be amortized over five years. As stated in Witness Coppola's testimony at the top
24 of page 62, the difference in his proposed regulatory liability and the Company's
25 proposed regulatory asset is a reduction in working capital of \$10 million.

Line
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1 **Q24. What does the AG propose the balance should be for deferred incentive**
2 **compensation?**

3 A24. AG Witness Coppola suggests the balance should be a liability and explains his
4 calculation of the incentive compensation regulatory liability on page 61 of his
5 direct testimony, starting at line 1. The calculations for 2023 are shown on his
6 Exhibit AG-20. In column (b) of Exhibit AG-20, Witness Coppola starts with the
7 incentive compensation forecasted in DTE Electric's rate case, Case No. U-20836.
8 He then applies a percentage of 2023 measures achieved in column (c) to determine
9 the expense he claims as the amount eligible for recovery, which is shown in
10 column (d) and totals \$5.943 million on line 6. He further compares that amount
11 to the base shown on line 5, resulting in a difference of \$6.792 million on line 7.
12 Witness Coppola suggests that this is the appropriate amount for a regulatory
13 liability. He further suggests that the liability be amortized over five years with a
14 credit to O&M of \$1.358 million as shown on line 8. This results in a 2025 ending
15 liability balance of \$5.434 million on line 9. The average balance of \$6.113 million
16 is shown on line 10.

17

18 **Q25. Do you have any concerns with the AG's calculations?**

19 A25. Witness Coppola's calculation contains two flaws. The first problem is the amount
20 he uses on Exhibit AG-20 in column (b). He used a forecast based on the estimated
21 expense in the (then projected) twelve-months ending October 2023 from a prior
22 Electric rate case (Case No. U-20836, filed January 21, 2022) instead of the actual
23 expense incurred during 2023. The mechanism design (like other similar tracker
24 mechanisms) compares actual expense incurred to a pre-determined base amount.
25 The Order in Case No. U-20836, page 301 states: "In addition, the Commission

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1 authorizes DTE Electric to implement a two-way tracker mechanism, which will
2 require refunds to customers if the 60% target level is not achieved or will allow
3 the company to recover additional funds if it exceeds the 60% target level, up to a
4 maximum of 100% target level. DTE Electric shall record the over- or under-
5 recovery, compared to the 60% base, in a regulatory asset or regulatory liability to
6 be included in the company's next general electric rate case." The correct starting
7 point for the calculation is actual 2023 incentive compensation expense related to
8 operating metrics, capped at 100% of the target.

9

10 **Q26. What is the second flaw in Witness Coppola's calculation?**

11 A26. As shown on his Exhibit AG-20, Witness Coppola is assuming performance results
12 in column (c) of 28.0%. These figures come from his Exhibit AG-21, page 2 and
13 are based on the number of metrics at Target or better. This calculation is flawed
14 because it assumes all the operating metrics underlying the incentive compensation
15 plan are based on whether performance Targets were met or not met (i.e., binary).
16 In fact, a performance weighted average is the basis for the actual incentive
17 compensation plan payouts that recognizes there are gradients between the
18 Threshold and Maximum performance levels, as more fully explained by Company
19 Witness Fix, rather than Witness Coppola's simplistic binary method. The
20 recognition of the gradients in performance can be seen on Company Witness
21 Cooper's Exhibit A-21, Schedule K4 in Case No. U-20836 (copy provided in
22 Rebuttal Exhibit A-37, Schedule BB3) and on Witness Fix's Exhibit A-21,
23 Schedule K2 in the instant case. Applying the weighting used in the plan design
24 results in the actual 2023 outcome ranging from 33.6% to 52.7% as shown on
25 Witness Fix's Rebuttal Exhibit A-35, Schedule Z1, line 47. This equates to expense

Line
No.

1 of \$5.987 million. This amount is shown on my Exhibit A-13, Schedule C5.10.1,
2 line 2, column (c). Comparing this to the base amount of \$12.735 million results
3 in a regulatory liability for 2023 of \$6.748 million shown on Exhibit A-13,
4 Schedule C5.10.1, line 4, column (c).

5

6 **Q27. What is your response to AG Witness Coppola's conclusion that there is no**
7 **recoverable balance related to deferred incentive compensation in 2022?**

8 A27. I disagree. The Commission's Order authorizing the deferral of certain incentive
9 compensation in Case No. U-20836 was issued on November 18, 2022 and the
10 Company recorded a deferral related to December 2022 costs. On page 60, starting
11 at line 11, Witness Coppola argues that based on his calculation of results achieved
12 compared to the target, the Company should have accrued a regulatory liability
13 instead of an asset and effectively disregards the accrual because the amount "was
14 de minimis." However, for the same reasons I explained related to the 2023
15 balance, Witness Coppola's assumptions for the 2022 balance are also flawed. He
16 states on page 60, at line 11 that the Company achieved only 52% of its target in
17 2022 (below the 60% base). Again, this assumed the targets are equally weighted.
18 On a weighted basis, the Company achieved over 80% of its operational target in
19 2022, as shown on his Exhibit A-21, row 47. Since this was above the baseline of
20 60%, the Company recorded a regulatory asset of \$856,000, shown on my Exhibit
21 A-13, Schedule C5.10.1 line 4, column (b). In response to discovery question
22 AGDE-3.128a, this amount was reduced by \$106,000 for a revised balance of
23 \$750,000.

Line
No.

1 **Q28. What is the appropriate amount of the deferral of incentive compensation for**
2 **2022 and 2023?**

3 A28. Adding the 2022 regulatory asset of \$750,000 to the 2023 regulatory liability of
4 \$6.748 million results in a net regulatory liability of \$5.998 million as of December
5 31, 2023.

6
7 **Q29. What is the resulting annual amortization expense?**

8 A29. If the Commission agrees with the AG's proposal to amortize the regulatory
9 liability over five years, the annual credit to O&M should be \$1.200 million (instead
10 of the \$1.358 million proposed by Witness Coppola). This would result in a 2025
11 ending balance of \$4.799 million and an average liability in working capital of
12 \$5.398 million. This is a \$9.282 million reduction in working capital compared to
13 the Company's filed position.

14

15 **Benefits Expense Rates**

16 **Q30. Did Staff propose adjustments to projected benefits costs?**

17 A30. Yes. Staff Witness Rueckert proposed a reduction to benefits. I will address the
18 impact of his expense assumptions on employee savings plan expense, general
19 benefits, and benefit administration fees. Witness Rueckert's proposed benefits
20 expenses are calculated on his Exhibit S-15.3. He calculated his projections for the
21 Employee Saving Plan, General Benefits and Benefits Administration Fees by
22 applying an assumed rate of change to 2023 actual costs. The 2023 figures are the
23 amount of expense recorded in O&M, net of amounts capitalized. The expense
24 portion for 2023 was 54.6% for the Employee Savings Plan, 58.7% for General
25 Benefits, and 54.8% for Benefits Administration Fees.

Line
No.

1 **Q31. Should the 2023 expense portion assumptions used by Staff Witness Rueckert**
2 **be applied to projected benefit costs in 2024 and 2025?**

3 A31. No. Given the financial challenges experienced by the Company in 2023, non-
4 recurring reductions to O&M were made during 2023. This resulted in a higher
5 proportion of related benefits to be capitalized than in a normal year. The Company
6 is returning to a more standard level of O&M in 2024 and beyond. Therefore, a
7 better forecast of benefits expense net of amounts capitalized would be based on
8 the expense percentages from 2022. Company Witness Fix supports Employee
9 Savings Plan expenses on his Rebuttal Exhibit A-35, Schedule Z2, and Company
10 Witness Hooper supports General Benefits and Benefit Administration Fees
11 expenses on his Rebuttal Exhibit A-36, Schedules AA3 and AA4. Applying an
12 expense rate based on 2022 data normalizes (increases) the three benefits expense
13 items by approximately \$3.6 million.

14

15 **Tree Trim Capitalization**

16 **Q32. What do the AG and MNSC (AG-MNSC) propose regarding the capitalization**
17 **of vegetation management (tree trimming) costs?**

18 A32. AG-MNSC Witness Alvarez discusses the accounting for vegetation management
19 starting on page 34 of his direct testimony. On page 37, line 1, Witness Alvarez
20 states, “I conclude that the only permitted capitalization of vegetation management
21 spending is in the initial construction of brand-new overhead distribution line. Any
22 other capitalization of tree trimming expense is an unequivocal violation of the
23 Michigan USOA.” At line 19 on page 38 he proposes that the Commission should
24 require DTE Electric to “explain the legitimacy of its decision to capitalize tree
25 trimming expenses for distribution capital programs” in its next rate case.

Line
No.

1 **Q33. How do you respond to Witness Alvarez's proposal?**

2 A33. I disagree. In Case No. U-21297, the Company explained that its accounting
3 policies for tree trimming comply with the requirements of the USoA. Another
4 review in a future rate case is unnecessary. Furthermore, Witness Alvarez's
5 interpretation of the USoA is flawed. At the top of page 37 he concludes, without
6 any basis, that vegetation management can only be capitalized for the initial
7 construction of brand-new overhead distribution line. This suggests that any
8 succeeding clearing is maintenance expense, even if the clearing is done to enable
9 construction work, which is incorrect.

10

11 **Q34. How is Witness Alvarez's interpretation of the USoA flawed?**

12 A34. Witness Alvarez ignores the USoA's definition of Maintenance included within the
13 Operating Expense Instructions. That definition states that maintenance expense
14 includes "Work performed specifically for the purpose of preventing failure,
15 restoring serviceability or maintaining life of plant." It also states that expense
16 includes "Replacing or adding minor items of plant which do not constitute a
17 retirement unit." Maintenance expense, by definition, is related to sustaining
18 existing assets. The tree trimming activities capitalized by the Company relate to
19 the installation of new assets (which *do* constitute a retirement unit), not to
20 maintaining existing assets.

21

22 **Q35. Which items from the USoA does Witness Alvarez cite?**

23 A35. Starting at line 4 on page 35 of his direct testimony, Witness Alvarez discusses that
24 the USoA description of account 365, Overhead Conductors and Devices, allows
25 for the capitalization of the initial cost of tree trimming. His conclusion assumes

Line
No.

1 that the capitalization of trimming is only applicable to the first installation of
2 electric lines, but not to the poles to which those lines are attached, or any other
3 adjacent assets. However, it cannot be expected that every possible type of cost be
4 listed in the description of each account. The USoA General Instruction No. 6,
5 Item Lists, says the following: “Lists of *items* appearing in the texts of the accounts
6 or elsewhere herein are for the purpose of more clearly indicating the application
7 of the prescribed accounting. The lists are intended to be representative, but not
8 exhaustive.” Also, Witness Alvarez refers to USoA Plant Instruction No. 9.

9
10 **Q36. What is Plant Instruction No. 9?**

11 A36. Plant Instruction No. 9 in the Electric USoA discusses the capitalization of
12 equipment which says, in part, “Also include those costs incurred with the first
13 clearing and grading of land and rights-of-way.” Starting at line 6 on page 35,
14 Witness Alvarez cites this sentence, asserting that this instruction defines “initial
15 cost” as used within the description of Account 365. However, the term “initial
16 cost” is not mentioned in the USoA discussion of equipment.

17
18 Regardless, the USoA does say that the cost of equipment shall include “expenses
19 incurred by the utility in unloading and placing the equipment in readiness to
20 operate.” Tree trimming required to install capital assets is clearly an expense
21 incurred to place equipment in readiness to operate. Thus, Witness Alvarez’s
22 conclusion that capitalization of tree trimming is restricted to the initial installation
23 of brand-new overhead distribution line is not supported by a full reading of the
24 USoA and should be rejected by the Commission.

Line
No.

1 **Q37. How does the Commission's Order in Case No. U-17767 inform the accounting**
2 **for tree trimming costs?**

3 A37. Witness Alvarez references Case No. U-17767 starting at the top of page 36 of his
4 direct testimony. In that case, the Company requested capital treatment for its
5 Enhanced Vegetation Management Program (EVMP) which expanded the
6 clearance area when trees are trimmed. The Commission concluded the expansion
7 of the clearance area should be accounted for as maintenance expense as it was not
8 a first clearing. Witness Alvarez suggests this should inform the accounting for
9 tree trim activities completed in conjunction with capital projects. Once again, he
10 has disregarded the full context of the issue.

11

12 **Q38. Can you provide more detail regarding the Company's EVMP?**

13 A38. As supported by Company Witness Pogats in Case No. U-17767, the EVMP was
14 initiated to help prevent outages and improve reliability. He stated in his direct
15 testimony: "With this enhanced practice, all vegetation that has the ability to grow
16 into or overhang the power line within five years is removed. Critical portions of
17 circuits, such as the area between the substation and the first recloser, will be
18 targeted for this method of clearance to maximize the impact of the investment¹."
19 The EVMP investment costs at issue were related to an improvement in
20 maintenance trimming that was not incurred to enable the installation of capital
21 assets. Rather, the program was intended to reduce the need to replace assets by
22 avoiding damage resulting from trees.

¹ MPSC Case No. U-17767 at 4T 365

Line
No.

1 **Q39. What did the Commission's Order in Case No. U-17767 say regarding tree**
2 **trim costs incurred in conjunction with capital work?**

3 A39. The Commission did not opine on the capitalization policy of tree trim as it relates
4 to the installation or replacement of capital assets in Case No. U-17767. Its Order
5 addressed only the accounting for the EVMP, a maintenance program. Therefore,
6 Witness Alvarez's argument that tree trimming costs related to capital work were
7 deemed to be maintenance expense by the Commission is inaccurate and should be
8 rejected.

9

10 **Q40. What would be the impact to the revenue requirement if the Commission**
11 **required all tree trimming costs to be expensed as O&M?**

12 A40. The issue raised by AG-MNSC is one of accounting classification, not prudence.
13 Therefore, if the Commission orders that all tree trimming costs associated with
14 capital work must be expensed as incurred, then the Commission should provide an
15 increase to O&M to reflect the change.

16

17 **Q41. Does this conclude your rebuttal testimony?**

18 A41. 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-21534

REBUTTAL TESTIMONY

OF

BENTE VILLADSEN

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1 **I. Introduction & Purpose**

2 **Q1. Please state your name and business address.**

3 A1. My name is Dr. Bente Villadsen (she/her/hers). My business address is One
4 Beacon Street, Suite 2600, Boston, Massachusetts, 02108.

5 **Q2. Are you the same Dr. Bente Villadsen who previously filed direct testimony**
6 **in this proceeding?**

7 A2. Yes.

8 **Q3. What is the purpose of your rebuttal testimony?**

9 A3. I have been asked by DTE Electric Company (“DTE Electric” or the
10 “Company”) to review and respond to the testimonies of the following
11 witnesses regarding the cost of equity and return on equity (“ROE”)
12 recommendations:

- 13 • Joseph Ufolla (Ufolla Testimony) on behalf of Michigan Public Service
14 Commission (“Commission” or “MPSC”) Staff (“Staff”),
- 15 • Sebastian Coppola (Coppola Testimony) on behalf of the Attorney
16 General’s (“AG”) office,
- 17 • Christopher Walters (Walters Testimony) on behalf of the Association
18 of Businesses Advocating Tariff Equity (“ABATE”),
- 19 • Matthew J. Bandyk (Bandyk Testimony) on behalf of Citizens Utility
20 Board of Michigan (“CUB”) and Michigan Environmental Council
21 (“MEC”) (collectively, “CUB-MEC”),
- 22 • Lisa A. Perry (Perry Testimony) on behalf of Walmart, Inc.
- 23 • Melissa Stults (Stults Testimony) on behalf of the City of Ann Arbor
24 (“AA”).

25 I only respond to those part of the testimonies mentioned above that discuss
26 cost of capital or ROE issues.

1 **Q4. Is there anything in MPSC Staff and Intervenor testimonies that caused**
2 **you to change your recommendations regarding DTE Electric's cost of**
3 **capital?**

4 A4. No. Having reviewed MPSC Staff's as well as Messrs. Walters, Coppola,
5 Bandyk, Ms. Perry and Dr. Stults (collectively, the "Intervenors") testimonies,
6 and having considered recent changes in economic conditions, I continue to find
7 that my original recommendation for the ROE of 10.50 percent on 50 percent
8 equity capital structure is reasonable.

9 **Q5. Please provide an overview of your rebuttal testimony.**

10 A5. I respond to the Intervenors' proposed ROEs and to their criticisms of my ROE
11 estimate of 10.50 percent percent from my Direct Testimony. First, I discuss
12 whether Intervenors' respective recommended ROE is appropriate given
13 today's financial markets, the status of electric utilities, and DTE Electric's
14 business risk. Second, I address Intervenors' respective approaches to
15 determining an appropriate ROE. Third, I address misunderstandings and
16 criticisms of my considerations of financial leverage. This adjustment is
17 necessary and well accepted by finance textbooks, academics, as well as used
18 in prior rate cases, to estimate the cost of equity for sample firms that have a
19 mixed capital structure. Fourth, I respond directly to other criticisms of my
20 comparable group or ROE methods – the use of the Empirical Capital Asset
21 Pricing Model ("ECAPM"), Discounted Cash Flow ("DCF") and market risk
22 premium ("MRP") approach. I continue to opine that 10.50 percent, as stated in
23 my Direct Testimony, is the ROE that DTE Electric should be allowed an
24 opportunity to earn.

25 **Q6. Are you sponsoring any exhibits as part of your rebuttal testimony?**

26 A6. Yes. I am sponsoring the following exhibits:

- 27 • Exhibit A-39, Schedule DD1: Comparison of ROE Witness Samples
- 28 • Exhibit A-39, Schedule DD2: Walters CAPM
- 29 • Exhibit A-39, Schedule DD3: Walters DCF

- 1 • Exhibit A-39, Schedule DD4: Walters Summary
- 2 • Exhibit A-39, Schedule DD5: Coppola DCF
- 3 • Exhibit A-39, Schedule DD6: Coppola Summary
- 4 • Exhibit A-39, Schedule DD7: Ufolla Summary
- 5 • Exhibit A-39, Schedule DD8: DTE Energy Capital Structure
- 6 • Exhibit A-39, Schedule DD9: Bandyk DCF
- 7 • Exhibit A-39, Schedule DD10: Change of ROE Recommendation Since U-
- 8 21297
- 9 • Exhibit A-39, Schedule DD11: Impact of Financial Leverage
- 10 • Exhibit A-39, Schedule DD12: Integrated Electric ROEs in 2024

11 II. Summary Recommendations and Responses

12 **Q7. Please summarize the parties' respective recommendations for DTE**
13 **Electric's authorized ROE and equity percentage.**

14 **A7.** Table 1 below summarizes the parties' respective recommendations for DTE
15 Electric's authorized ROE and equity percentage.

16 **TABLE 1: SUMMARY OF RECOMMENDATIONS¹**

	Recommended ROE	Low end for ROE	High end for ROE
Company, Villadsen	10.50%	10.25%	11.0%
Staff, Ufolla	9.90%	9.30%	10.30%
AG, Coppola ¹⁾	9.85%	9.26%	10.57%
ABATE, Walters	9.60%	9.20%	10.0%
CUB-MEC, Bandyk ²⁾	9.30%	8.59%	9.90%
Walmart, Perry	< 10.50%		
AA, Stults	< 9.90%		

17 ¹⁾ Coppola's range displays range of the estimates used for his recommendation.

18 ²⁾ Bandyk's range displays range considered for his recommendation.

¹ Villadsen Direct, p. 6; Ufolla Testimony, p. 8; Coppola Testimony, p. 100 and AG-27; Walters Testimony, p. 3; Bandyk Testimony, p. 23 and Workpaper Bandyk workpapers U-21534; neither the Perry Testimony nor the Stults Testimony has an explicit recommendation.

1 Of note, the Ufolla Testimony and the Coppola Testimony recommended no
2 changes to the capital structure submitted by DTE Electric, while the Walters
3 Testimony incorrectly claimed the Company seeks a 53.5 percent equity
4 percentage, but ultimately did not appear to make an alternative
5 recommendation.² The Bandyk Testimony, the Perry Testimony, and the Stults
6 Testimony did not specifically address capital structure.

7 **Q8. What issues from the Staff's and Intervenor's direct testimony are you**
8 **addressing in your rebuttal testimony?**

9 A8. Specifically, I am addressing the following issues:

- 10 • Whether the recommended ROEs of 9.90 percent (Ufolla Testimony),
11 9.85 percent (Coppola Testimony), 9.60 percent (Walters Testimony),
12 or 9.30 percent (Bandyk Testimony) are reasonable in today's
13 financial environment given DTE Electric's business risks.
- 14 • Whether the proposal to lower the ROE from the currently allowed
15 9.90 percent as suggested by Dr. Stults is reasonable and whether Ms.
16 Perry's views on the currently allowed ROEs across the U.S. is
17 reasonable.
- 18 • The inputs and specifications of the models relied upon by Mr. Ufolla,
19 Mr. Coppola, Mr. Walters, and Mr. Bandyk as well as the approach
20 taken by Ms. Perry and Dr. Stults.
- 21 • Staff and Intervenor's critique of my Capital Asset Pricing Model
22 ("CAPM"), DCF, and risk premium implementation.
- 23 • The importance of considering financial leverage.
- 24 • DTE Electric's business risk considerations.

² Walters Testimony, p. 25. See Rebuttal Testimony of Company Witness Lepczyk for additional discussion of ABATE Witness Walters' capital structure testimony, including re-confirmation of the Company's requested 50% equity percentage.

1 **Q9. What are your key conclusions?**

2 A9. Based on my review and analysis of MPSC Staff and Intervenors testimony, I
3 find that their recommended ROEs are too low in today's financial environment
4 and that my recommened ROE of 10.50 percent remains valid. I also find that
5 several missteps and improper inputs to the models downward biases the results.
6 To summarize:

- 7
 - Indications are that the cost of equity has increased since DTE Electric's
8 last rate case (Case No. U-21297) and experts who submitted testimony in
9 both U-21297 and this matter appear to agree as Mr. Ufolla, Mr. Coppola,
10 and Mr. Walters all have inceased their ROE recommendation.³

11 **Q10. Please summarize your testimony.**

12 A10. Having reviewed the testimony of MPSC Staff and Intervenors, I find the
13 following:

- 14
 - MSPC Staff's and Intervenors' recommendations are too low in
15 today's economic and financial environment. When viewed in
16 the proper context and modified to properly reflect current
17 inputs and best practices, the results are supportive of DTE
18 Electric's requested ROE of 10.50 percent.
 - The request for an equity percentage of 50 percent is below that
19 recently awarded to electric utilities and reasonable.
 - Contrary to Messrs. Ufolla, Walters, and Coppola's statements,
20 a consideration of financial leverage is merited from both a
21 financial economics and regulatory perspective. Ignoring
22 financial leverage downwardly biases the results by at least 50
23 basis points. Ignoring
24 financial leverage downwardly biases the results by at least 50
25 basis points.

³ Comparing the recommendations in U-21297 to those in this docket, U-21534: Mr. Ufolla 9.80% versus 9.90% in this instant case, Mr. Coppola 9.80% versus 9.85% in this instant case, and Mr. Walters 9.55% versus 9.60% in this instant case. Mr. Bandyk did not submit testimony in U-21297.

1 Regarding the implementation of the cost of equity estimation models, I note
2 the following key flaws in MSPC Staff's and Intervenors' approaches:

- 3 • Assigning an excessive weight to the DCF results, as does Mr.
4 Coppola, downward biases his estimated cost of equity.
- 5 • For the CAPM:
 - 6 ○ The use of an outdated and short-term Market Risk Premium
7 ("MRP"), as does Mr. Bandyk, downward biases his estimated
8 cost of equity.
 - 9 ○ Relying on historical betas, as Mr. Walters does, fails to
10 recognize that the systematic risk of utilities has changed during
11 the last decade.
 - 12 ○ The use of Kroll's recommended MRP without using the
13 recommended risk-free rate or using surveys, as does Mr.
14 Bandyk, downward biases the CAPM results.
- 15 • For the DCF Model:
 - 16 ○ Considering only the multi-stage DCF leads to a downward bias
17 in the estimation results from Mr. Bandyk.
 - 18 ○ The sustainable growth model as implemented by Mr. Walters
19 is internally inconsistent in that the inputs used for the ROE
20 differ substantially from the calculated ROE.
 - 21 ○ Reliance on negative growth rates in the DCF model, like Mr.
22 Ufolla does, leads to a downward bias in the cost of equity
23 estimated using the DCF model.
- 24 • For the Risk Premium Model:
 - 25 ○ Using a regression approach to determine the inherent risk
26 premium in allowed ROEs takes into account the relationship
27 between the risk premium and interest rates. The calculation of

simple averages, which Messrs. Ufolla, Walters, and Coppola
rely on, fails to consider this relationship.

- Financial models are needed to estimate the current cost of equity,
so testimonies without such analysis like Dr. Stults and Ms. Perry
should not be considered.

In Sections II.B, II.C, II.D and II.E I discuss these issues in more detail and
demonstrate the impact of some key implementation issues. Table 2 below
summarizes the impact of modifying these implementation issues.

**TABLE 2: SUMMARY OF MODIFICATIONS TO STAFF'S AND INTERVENORS'
MODEL IMPLEMENTATIONS (AVERAGES ONLY)⁴**

	Staff Ufolla	AG Coppola	ABATE Walters	CUB-MEC Bandyk
DCF				
As filed	9.78%	9.26%	9.45%	8.66%
Modified	9.76%	9.43%	9.63%	9.61 %
CAPM				
As filed	10.23%	10.57%	10.39%	8.53%
Modified	10.38%	10.57%	10.67%	10.33%
Risk Premium				
As filed	(8.63% to 10.05%)	10.10%	9.95% - 10.27%	n/a
Modified	10.05%	10.10%	10.11%	n/a
Recommendation				
As filed	9.90%	9.85%	9.60%	9.30%
Modified ¹⁾	10.06%	10.04% (rounding to 10.09%)	10.14%	9.97%

1) Simple average of the Modified results for the DCF, CAPM, and Risk
Premium.

⁴ As filed results from Ufolla Testimony, p. 21 noting that the 8.63% and 10.05% are his lowest and highest number – not a recommendation; Coppola Testimony, Exhibit AG-27; and Walters Testimony, pp. 37, 42 and 52.

1 I note that once proper inputs and implementation are taken into account the
2 range of estimates is relatively narrow from about 10.0 percent to about 10.15
3 percent before any consideration of financial leverage. As financial leverage
4 account for at least 50 basis points, the data clearly supports the Company's
5 request for a ROE of 10.50 percent.

6 II.A. Today's Financial Environment Requires an ROE
7 Higher than that Proposed by MPSC Staff and
8 Intervenors

9 **Q11. How would you describe MPSC Staff and Intervenors' recommended**
10 **ROEs?**

11 A11. The ROEs recommended by MPSC Staff and Intervenors are too low, as they
12 all recommend that the authorized ROE remains the same (Ufolla) or decrease
13 (Coppola, Walters, Bandyk, Stults), while indications are that the cost of equity
14 has increased since DTE Electric's cost of equity was last assessed.⁵ Messrs.
15 Ufolla, Coppola, and Walters all recognize that and recommend a slightly
16 higher ROE now than they did in the Company's last rate case, Case No. U-
17 21297.⁶

18 Looking to the yield on the 20-year Treasury bond in the month immediately
19 preceding the filing in the instant case, the last rate case and as of the present
20 date, I note that this yield was 3.81 percent in January 2023 (shortly before U-
21 21297 was filed), 4.04 percent in June 2023 (at the time Staff and Intervenors
22 filed testimony in U-21297), and Mr. Walters refers to the current (July 2024)
23 yield as 4.57 percent.⁷ Thus, the 20-year Treasury bond yield is higher now

⁵ Case No. U-21297 filed February 2023 with intervener/Staff rebuttal in June 2023 and a decision in December 2023 (Order in U-21297, pp. 1, 3).

⁶ Comparing the recommendations in Table 1 to those submitted U-21297 (e.g., Figure 1 in Rebuttal Testimony of Bente Villadsen, Case No. U-21297, p. 5). See Exhibit A-39, Schedule DD10 for details.

⁷ Using monthly data from the Federal Reserve, St. Louis and the Walters Testimony pp. 45-46 calculates the July 2024 yield as 4.57%: [Treasury Constant Maturity | FRED | St. Louis Fed \(stlouisfed.org\)](https://fred.stlouisfed.org/)

1 than during the Company's last rate case. Similarly, the yield on 10- and 30-
2 year Treasury bonds have increased by approximately 50 basis points since
3 Staff and Intervenor filed testimony in Case No. U-21297 on June 13, 2023
4 and by more than that since DTE Electric filed direct testimony in that
5 proceeding on February 10, 2023. Similarly, the Bloomberg forecasted MRP
6 is higher than that Bloomberg calculated in U-21297, while the historical MRP
7 has declined slightly.⁸ These are indications of a higher cost of capital.

8 Of particular note, the ROE recommendation of Mr. Bandyk is below that
9 allowed for any integrated electric utility in 2024 except Public Service New
10 Mexico, which is a unique decision that is under appeal at the New Mexico
11 Supreme Court.⁹ The recommendation is also well below that of other Staff and
12 Intervenor witnesses indicating that he relies on outlier inputs or models. In
13 this case, the low estimates are predominantly caused by Mr. Bandyk exclusive
14 reliance on the multi-stage DCF and an unreliable low MRP in his CAPM.

15 In addition, I note that the peer group simple average of Mr. Coppola's cost of
16 equity estimates from the DCF model, the CAPM, and the risk premium model
17 is 10.04 percent prior to taking Mr. Coppola's rounding into account and 10.09
18 percent once his rounding suggestion is considered.¹⁰

19 Further, while Mr. Walters displays various ROE ranges in Figure CCW-5, they
20 reflect a substantial bias towards the low-end of his estimated range (9.20
21 percent to 10.20 percent) in that every single estimation method has a range
22 above the recommended range while less than half of his estimation methods
23 have any results below his lower bound.¹¹

24 Lastly, I note that neither Ms. Perry nor Dr. Stults undertake a cost of equity
25 study, but merely comment on the ROE that DTE Electric should be allowed.

⁸ Villadsen Direct, Figure 9 p. 34 versus Villadsen Direct Testimony in U-21297, Figure 10 p. 39.

⁹ Exhibit A-39, DD12. The Public Service New Mexico rate case was appealed to the NM Supreme Court on March 14, 2024, and the case has, to the best of my knowledge, yet to be resolved.

¹⁰ See Exhibit A-39, DD6 for details.

¹¹ Walters Testimony, Figure CCW-5, p. 58.

1 Without a contemporaneous study of the cost of equity, they offer no evidence
2 to support a specific ROE or direction of change for the ROE.

3 **Q12. How would you describe MPSC Staff's and Intervenors' recommended**
4 **ROEs?**

5 A12. The recommended ROEs are at or lower than DTE Electric's currently allowed
6 ROE of 9.90 percent and lower than the ROE most recently allowed in
7 Michigan¹² despite indications that the cost of equity has increased. Of note, the
8 Commission has in the past acknowledged the importance of monitoring "a
9 variety of market factors in future applications, including market reactions to
10 recent events and measures of volatility and uncertainty, as well as measures of
11 investor confidence, and the utility's risk profile."¹³ Therefore, the fact that
12 interest rates are higher, while betas and growth rates are comparable to those
13 in DTE Electric's most recent case needs to be acknowledged through an
14 increase in the allowed ROE.

15 In the case of Mr. Coppola, placing $\frac{1}{2}$ weight on the DCF results and only $\frac{1}{4}$ on
16 each of the CAPM and risk premium results downward biases the ROE results.
17 Specifically, if Mr. Coppola were to take a simple average of the results from
18 his three models, the average ROE would increase to 10.08 percent (after his
19 0.05 percent rounding) for an increase of more than 20 basis points.¹⁴

20 Mr. Walters resorts to "historic" betas using data back to 2014¹⁵ to obtain his
21 lower than merited CAPM as the historic betas downward bias his CAPM by
22 about 30 basis points. For the DCF model, I consider Mr. Walters' sustainable
23 growth model flawed and therefore it should be ignored. Leaving out the
24 sustainable DCF model, the average of Mr. Walters' DCF estimates increases

¹² Most recently the Commission approved an ROE of 9.90% in both Case Nos U-21389 and U-21297.

¹³ Michigan Public Service Commission, Order in U-20561, p. 177.

¹⁴ Comparing the peer group simple average of 9.98% = (9.26%+10.57%+10.10%)/3 to the weighted average of 9.80% calculated by Mr. Coppola in Exhibit AG-27.

¹⁵ Walters Testimony, page 46.

1 by 20 basis points.¹⁶ For the risk premium models, I am concerned that Mr.
2 Ufolla's risk premium model, which relies on Treasury bond yields as described
3 on pages 19-20 of his testimony, is biased due to the inclusion of periods of
4 very high bond yields or large spreads between utility bond yields and Treasury
5 bond yields. As the result is unusually low and outside the range found by other
6 witnesses, I ignored this result in the modified row for Mr. Ufolla's risk
7 premium in Table 2 above.

8 Lastly, I consider Mr. Bandyk's reliance on only a multi-stage DCF model¹⁷
9 insufficient during the energy transition and his use of unconventional sources
10 for his market risk premium in the CAPM downward biases his CAPM
11 substantially.

12 Dr. Stults' ROE related testimony focuses on (i) no credit rating agency has
13 reacted negatively¹⁸, (ii) DTE Electric's authorized ROE should be reduced,
14 and (iii) DTE Electric has requested a higher ROE than awarded in recent years.
15 However, Dr. Stults does not perform any analysis of the current cost of equity
16 such as DTE Electric is and therefore has no basis for suggesting a lower ROE.¹⁹
17 As noted above, indications are that the cost of equity has increased as noted in
18 my direct testimony p. 14. Further, she fails to acknowledge that credit rating
19 agencies are concerned about creditworthiness and not the return to
20 shareholders. As such, she is focused on one of the Supreme Court's
21 requirement; namely that (i) the return should be adequate, under efficient and
22 economical management for the utility to maintain and supports its credit ...",
23 but ignores the two other tenants of *Hope* and *Bluefield*. These additional
24 requirements are that (ii) the return should be commensurate with the returns
25 on investments in other enterprises having corresponding risk and (iii) the return

¹⁶ Calculated as (Average of DCF models w/o Sustainable GR) – Average of all 3 DCF Models; see Exhibit A-39, Schedule DD3 for details.

¹⁷ Bandyk Testimony, page 19-20

¹⁸ Stults Testimony, p 11

¹⁹ Stults Testimony, p. 13.

1 should be reasonably sufficient to assure confidence in the financial soundness
2 of the utility.²⁰

3 Ms. Perry focuses on recently allowed ROEs in Michigan and nationwide to
4 suggest that the ROE requested by the Company is too high,²¹ but fails to
5 acknowledge that DTE Electric's requested equity percentage is lower than that
6 allowed to the average electric utility and that the cost of equity is forward-
7 looking.

8 Lastly, another factor driving the difference between my estimate of DTE
9 Electric's ROE and Staff and the Intervenor's estimates is that they (with the
10 exception of Mr. Bandyk) ignore the effects of financial risk on the cost of
11 equity. This is contrary to not only finance theory and practice, but also to
12 regulatory precedent. Indeed, Mr. Walters provides a work paper he
13 downloaded from S&P Global that includes levered and unlevered betas for his
14 proxy group.²² Clearly, S&P Global and Mr. Walters are aware that financial
15 leverage adjustments for the cost of equity are well accepted by the market and
16 for the regulated utility industry.

17 While I cover the relationship between the equity percentage and the cost of
18 equity in Section II.C, I note that standard Masters of Business Administration
19 (MBA) textbooks such as Berk & DeMarzo (2013), Brealey, Myers & Allen
20 (2011), Ross, Westerfield & Jaffe (2014)²³ as well as commercial providers of
21 cost of capital estimates (e.g., Duff & Phelps)²⁴ and regulatory commissions²⁵

²⁰ See, for example, Villadsen Direct, pp. 9-10.

²¹ Perry Testimony, p. 9.

²² Walters Exhibit CCW Confidential WP 22, tab "Instructions.

²³ See, for example, Berk & DeMarzo 2013, p. 489. Similar comments appear in Richard A. Brealey, Stewart C. Myers, and Franklin Allen, 2014, *Principles of Corporate Finance*, 11th edition, McGraw-Hill Irwin (Brealey, Myers & Allen 2014), p. 433 and Ross, S., Westerfield, R., Jaffe, J. (2014), *Corporate Finance*, pp.492-95.

²⁴ See, for example, Duff & Phelps, "2017 Valuation Handbook – U.S. Guide to Cost of Capital," p. 1-15.

²⁵ See, for example, Federal Communications Commission, "Report and Order, Order and Order on Reconsideration, and Further Notice of Proposed Rulemaking," FCC 16-33, issued March 30, 2016,

1 have recognized that the financial risk of a company increases with its
2 proportion of debt that is used to finance its operations (i.e., its leverage). For
3 example, the Florida Public Service Commission has relied on a formula
4 approach to the allowed ROE for water utilities that explicitly recognized that
5 a lower equity percentage merits a higher ROE.²⁶ I discuss the issue of financial
6 leverage in the Section II.D below.

7 **Q13. Do you have any preliminary comments on Staff's or Intervenors'**
8 **criticisms of your recommended ROE?**

9 A13. First, for the CAPM / ECAPM I did not rely on the After-Tax, Weighted-
10 Average Cost of Capital ("ATWACC") approach²⁷ and as the risk premium
11 relies on data from a sample with an average of a little over 50 percent equity,
12 the results are directly comparable. Second, I continue to find that it is necessary
13 to consider capital structure when determining the cost of equity²⁸ and therefore
14 discuss my reasons below in Section II.D. Third, it is absolutely necessary to
15 use current estimates of the systematic risk, as I do as well as do Mr. Ufolla,
16 Mr. Coppola, and Mr. Bandyk. The critique of that as well as the use of
17 estimates that are up to 10 years old should simply be ignored.²⁹ Lastly, the
18 critique of my ECAPM is misplaced, but because it has little to no effect on the
19 estimated ROE, I have relegated any discussion to an appendix.³⁰

pp 3189-3190 and p. 3210. The Federal Energy Regulatory Board in Cost of New Entry studies for electric (Docket ER14-2940-000, November 28, 2014, ¶81), the Surface Transportation Board (Docket No. EP 558 (Sub-No 18) as well as foreign regulators such as the British Columbia Utilities Commission ("Generic Cost of Capital Proceeding (Stage 1), Decision and Order G-236-23," issued September 5, 2023). In addition, the California Public Utilities Commission relied on Hamada unlevered / relevered data in D.12-12-034.

²⁶ Florida Public Service Commission, "Order No. PSC-2017-0361-FOF-WS," p. 126 lists the equity percentage as 49.27.

²⁷ Villadsen Direct, Figure 10, p. 35.

²⁸ Bandyk Testimony, p. 18 acknowledges that it is necessary to reflect capital structure in the determination of the relevant cost of equity.

²⁹ Walters Testimony, pp. 57 and 45.

³⁰ I note that the Ufolla Testimony, p. 17 makes a similar observation.

II.B. Response to Relied Upon Models and Inputs

Q14. Do you have any comments on Staff's and Intervenor's selection of comparable companies?

A14. Yes. Mr. Walters uses the same electric utility companies as I except ALLETE, which I also would exclude today due to its recently announced plan to be acquired by Canada Pension Plan Investment Board and Global Infrastructure Partners.³¹ Mr. Bandyk similarly relies on the same companies as do I but excludes Alliant – I found no explanation for this exclusion in the Bandyk Testimony.³² Like Mr. Ufolla, Mr. Coppola, and Mr. Walters, I find Alliant to be an appropriate comparator. Mr. Ufolla relies on 18 electric utilities including 13 of the electric utilities I use plus an additional five companies (Avangrid, Consolidated Edison, Dominion, Eversource, PPL Corporation),³³ while Mr. Coppola relies on 10 electric utilities of which eight overlap with my sample,³⁴ while he also adds Consolidated Edison and PNM Resources. First, I think it is preferable to have more peer utility companies in the comparable group than do Mr. Ufolla and Mr. Coppola given the availability of such companies. Second, I am concerned that Mr. Ufolla's and Mr. Coppola's samples include distribution only companies.³⁵ Additionally, I am puzzled that Mr. Coppola includes Avangrid and PNM Resources, which only recently abandoned their merger agreement.³⁶ Third, Mr. Coppola's sample has an

³¹ ALLETE Press Release, "ALLETE Enters Agreement to be Acquired by a Partnership Led by Canada Pension Plan Investment Board and Global Infrastructure Partners to Advance 'Sustainability-in-Action' Strategy," May 6, 2024. [ALLETE Enters Agreement to be Acquired by a Partnership Led by Canada Pension Plan Investment Board and Global Infrastructure Partners to Advance 'Sustainability-in-Action' Strategy | ALLETE, Inc.](#)

³² See also Bandyk Workpapers, tab "Hamada Beta."

³³ See Exhibit A-39, Schedule DD1 for a comparison of the samples the witnesses relied upon.

³⁴ *Ibid.*

³⁵ Both include Consolidated Edison and Mr. Ufolla also includes Eversource.

³⁶ PNM Resources, "PNM Resources Announces Avangrid Termination of Merger Agreement, Schedules Financial Update," Press Release, January 2, 2024; [PNM Resources Announces Avangrid Termination of Merger Agreement, Schedules Financial Update \(prnewswire.com\)](#)

1 average growth rate that is below that of other witnesses, which plausibly is
2 the cause for his lower DCF results³⁷.

3 **Q15. Do you have a response to the critique of your sample selection?**

4 A15. Yes. Mr. Coppola critiques my proxy group for not meeting my own selection
5 criteria. I respectfully disagree. At the time of the selection, ALLETE had yet
6 to announce its sale and other companies' transactions³⁸ did not constitute 25
7 percent or more of the market value. Moreover, as I do not adjust for
8 differences in size and the literature on the impact on cost of equity from size
9 is disputed in the academic literature,³⁹ I disagree with eliminating entities that
10 are larger or smaller than DTE Electric as long as the entities have sufficient
11 trading volume to, in a statistical sense, reliably estimate the cost of equity.
12 Additionally, if Mr. Coppola believes the CAPM underestimates the cost of
13 equity for small companies and over estimates it for large companies,⁴⁰ this
14 effect can be eliminated by adding/subtracting the empirical premium.⁴¹ Lastly,
15 through the elimination of companies, Mr. Coppola ends up with a sample
16 whose average growth rate is lower than those of other witnesses – specifically
17 the elimination of larger companies such as Duke, Exelon, Nextera and
18 Southern Company eliminates entities, which are poised for growth through
19 investments and (by that measure) are comparable to DTE Electric.⁴²
20 As I do not believe the sample differences are the key drivers of the difference
21 in results, I shall not address the samples selected by the witnesses further.

³⁷ Mr. Ufolla's average sample beta is 0.94, Mr. Coppola's average sample beta is 0.91 and the Villadsen Direct found an average sample beta of 0.93. The samples' average growth rate before any eliminations or adjustments was 5.7% for Mr. Ufolla, 5.215% for Mr. Coppola (taking into account only those companies for which Mr. Coppola reports a growth rate in AG-28, p. 1), 6.29% for Mr. Walters and 5.3% in the Villadsen Direct.

³⁸ Coppola Testimony p. 79 mentions American Electric Power ("AEP") and CenterPoint Energy.

³⁹ For example, Kroll's Cost of Capital Navigator continues to report size premia, while, for example, Ron Alquist, Ronen Israel & Tobias Moskowitz, "Fact, Fiction, and the Size Effect," *The Journal of Portfolio Management*, vol 45, 2018, concludes there is no size effect.

⁴⁰ Coppola Testimony, p. 77 states that he removes companies "due to size considerations."

⁴¹ Using the size premium that is reported by, for example, Kroll Cost of Capital Navigator.

⁴² Coppola Testimony, p. 77. Villadsen Direct, p. 44 found DTE Electric to have higher capital expenditures than the sample.

1 **Q16. What is your view on the models and inputs relied upon by Staff and**
2 **Intervenors?**

3 A16. All witnesses (including myself) that provide an explicit recommendation use
4 versions of the CAPM and DCF model. Mr. Ufolla, Mr. Coppola, Mr. Walters,
5 and I also estimate one or more versions of a risk premium model.

6 A key concern with Mr. Coppola's use of the models when recommending a
7 return on equity is that he over-emphasized the DCF model's results, which he
8 weighs by $\frac{1}{2}$ while the CAPM and Risk Premium is weighted by only $\frac{1}{4}$ each.
9 The modified results in Table 2 above therefore use a more common approach
10 and weigh the results equally ($\frac{1}{3}$ each).⁴³

11 I summarized the results reported by the witnesses and those obtained from key
12 modifications in Table 2 above. Of note, Table 2 above does not consider
13 financial leverage unless the witness incorporates such leverage. I consider the
14 impact of financial leverage in Section II.C below.

15 I next address my concerns with the model implementations in turn.

16 **II.B.1. DCF Models**

17 **Q17. How did MPSC Staff and Intervenors implement their DCF models?**

18 A17. Mr. Ufolla implements a single-stage DCF using the average of the company-
19 specific growth rates from Yahoo, Value Line, and Zacks. He obtains his
20 dividend yield from Value Line.⁴⁴ Mr. Coppola implements a single-stage DCF
21 model using company specific growth rates from Value Line and Yahoo, which
22 he averages. He relies on a 30-day average stock price ending June 12, 2024
23 and a forecasted dividend from Value Line.⁴⁵ Mr. Walters implements a

⁴³ For example, the Federal Energy Regulatory Commission (Order 569-A) and the Surface Transportation Board (STB Ex parte No. 664 (Sub-No. 1)) assign equal weight to the methods they rely on.

⁴⁴ Ufolla Testimony, p. 12.

⁴⁵ Coppola Testimony, Exhibit AG-28.

1 constant-growth model, a sustainable growth model, and a multi-stage growth
2 model. In his constant-growth DCF model, Mr. Walters relies on the average
3 of three professional security analysts' company-specific growth rate forecasts
4 in his constant growth DCF model, using 13-week average stock prices ending
5 June 24. His sustainable growth DCF model relies solely on Value Line
6 forecasts, while his multi-stage DCF uses analysts forecasts and Gross
7 Domestic Product ("GDP") growth.⁴⁶ Finally, Mr. Bandyk simply adopts the
8 Villadsen Direct's multi-stage After-Tax Weighted Average Cost of Capital,
9 which he then adjusts to 58 percent equity (Villadsen Direct's average market
10 value equity percentage for the sample).⁴⁷

11 **Q18. What comments do you have on these models and implementations?**

12 A18. Mr. Ufolla uses the average of the growth rates from Yahoo, Value Line and
13 Zacks as his company-specific growth rate. However, the Yahoo growth rate
14 for OGE Energy Corp is negative 12.34 percent, which is not a reliable going
15 forward estimate as it would cause the company to fail. Therefore, it would be
16 more appropriate to rely solely on the growth rates from Value Line and Zacks
17 (the average of which is 5.75 percent and in line with the sample average).⁴⁸
18 Using that growth rate for OGE results in its DCF-based cost of equity being
19 10.49 percent and the sample average and median becomes 10.13 percent and
20 9.85 percent, respectively.⁴⁹ Second, Mr. Ufolla relies on a formula that
21 determines the year one dividend yield using $\frac{1}{2}$ of the company-specific growth
22 rate. It would be more appropriate to grow the dividend yield by the full growth
23 rate, which would increase the DCF estimate by a small amount.

24 Mr. Coppola relies on lower growth rates than Staff, Mr. Walters, and myself.
25 This appears to be caused by his elimination of large growth entities, as noted

⁴⁶ Walters Testimony, Exhibit AB-6 to AB-11.

⁴⁷ Bandyk Testimony, Exhibit CUB-9.

⁴⁸ Ufolla Testimony, Exhibit S-4, Schedule D-5.

⁴⁹ It could also be appropriate to eliminate Dominion, whose DCF cost of equity estimate is 16.32% and therefore more than 1.5 times the average (which is FERC's elimination criteria). In Table 2, I eliminated the negative growth rate for OGE and Dominion to be conservative.

1 above, which plausibly downward biases his results by 15 to 109 basis points.⁵⁰

2 As Mr. Coppola relies on a single-stage growth DCF model, a reduction in the
3 growth rate of 15 basis points results in a reduction in the estimated ROE of 15
4 basis points. My direct testimony found an average growth rate of 5.3 percent,
5 Mr. Ufolla found an average growth rate of 5.7 percent, and Mr. Walters
6 consensus growth rate is 6.29 percent, so Mr. Coppola is 0.15 percent, 0.55
7 percent and 1.14 percent lower. I find a reasonable measure of the downward
8 bias is 0.15 percent to 1.14 percent.

9 Mr. Walters' sustainable growth model suffers from at least two issues. One, it
10 necessarily relies on only one source for its growth rates – Value Line. Two,
11 an input to the model, the expected ROE as forecasted by Value Line averages
12 11.13 percent,⁵¹ but Mr. Walters calculates an average ROE of 9.10 percent
13 using his sustainable growth model.⁵² This is simply inconsistent, and Mr.
14 Walters sustainable growth model should be ignored. Looking solely to Mr.
15 Walters' Constant Growth Model (Analysts' Growth) and Multi-Stage DCF
16 Model, the average of his DCF results changes from 9.45 percent to 9.63
17 percent.

18 Mr. Bandyk relies on my multi-stage DCF, while Mr. Ufolla, Mr. Coppola, Mr.
19 Walters and I all include a single-stage model. Thus, if Mr. Bandyk wants to
20 use my results and incorporate his adjustment, he ought to use an average of the
21 single-stage and multistage models. Doing so would increase his DCF-based
22 results from 8.66 percent to 9.61 percent with the single-stage DCF resulting in
23 a cost of equity of 10.43 percent.⁵³

⁵⁰ I compare the average growth rate from the Ufolla Testimony, the Walters Testimony, and the Villadsen Direct to the 5.15% average growth rate, I obtain, when I average the nine growth rates displayed in AG-28, column (h). It appears that the 4.63% reported as the average for the column assumes 10 companies in the average although there are only 9 as the row for Alliant Energy shown "N.M."

⁵¹ CCW Public WP 8, Tab AB-9.

⁵² CWW Public WP 8, Tab AB-10.

⁵³ See Exhibit A-39, DD9 for details.

1 **Q19. How about Staff's and Intervenors' criticisms of your implementation of**
2 **the DCF model?**

3 A19. I address the critique of considering financial leverage in Section II.C below
4 and therefore respond only to other critiques here.

5 I disagree with Mr. Walters that I should have placed more weight on the multi-
6 stage DCF model.⁵⁴ As I explained in my direct testimony, p. 38, the multi-
7 stage DCF results are out-of-line with other estimates and the general GDP
8 growth that is used in the multi-stage model in later years may fail to capture
9 the transition towards a low-carbon economy, which may take longer than what
10 the growth rates in the multi-stage DCF model reflects.⁵⁵ Mr. Ufolla and Mr.
11 Coppola rely on a single-stage DCF model and thus reflect company-specific
12 growth in their models.

13 **II.B.2. CAPM-Based Models**

14 **Q20. How do Staff and Intervenors implement the CAPM?**

15 A20. Mr. Ufolla implements the CAPM using a forecasted risk-free rate of 3.85
16 percent, Value Line betas and a MRP, which reflects the historical difference
17 between the total return on the S&P 500 and the income returns on long-term
18 government bonds (6.80 percent).⁵⁶

19 Mr. Coppola implements his CAPM using a forecasted risk-free rate of 4.05
20 percent, Value Line betas and a MRP of 7.17 percent, which he obtains from
21 Ibbotson's data up to 2022.⁵⁷

22 Mr. Walters implements nine versions of the CAPM, where he varies the risk-
23 free rate, betas and the MRPs. Specifically, he relies on a forecasted risk-free

⁵⁴ Walters Testimony, p. 61.

⁵⁵ My multi-stage DCF reflects analysts' growth rates during the first five years, then linearly moves the growth rate towards the GDP growth rate and fully reflects the GDP growth after year 10.

⁵⁶ Ufolla Testimony, Exhibit S-4, D-5.

⁵⁷ Coppola Testimony, Exhibit AG-29.

1 rate of 4.30 percent and a current risk-free rate of 4.57 percent. Mr. Walters
2 uses Value Line betas as do all other witnesses, current betas from S&P Global
3 and then also uses so-called historical betas, which are calculated as an average
4 from 2014 to today.⁵⁸ The MRP is (i) obtained from Duff & Phelps and
5 matched with their recommended risk-free rate,⁵⁹ (ii) based on a risk-premium
6 derived method and matched with a forecasted risk-free rate, or (iii) based on a
7 DCF model of the S&P 500 and matched with a forecasted MRP.

8 Unlike the other witnesses, Mr. Bandyk accounts for differences in financial
9 leverage by relying on the average Hamada adjusted beta from my sample.⁶⁰
10 Notably, Mr. Bandyk agrees “on the need to adjust beta to reflect that a higher
11 level of debt within a company’s capital structure increases the risk of equity.”⁶¹
12 He then implements the CAPM using a risk-free rate of 4.0 percent, Value Line
13 betas and a MRP of 4.87 percent, which is calculated as the average of the MRP
14 reported by IESE, the Kroll recommended MRP, and one of Damodaran’s
15 MRPs.⁶²

16 **Q21. What comments do you have on Mr. Ufolla’s CAPM implementation?**

17 A21. While Mr. Ufolla’s risk-free rate is lower than that of other witnesses and lower
18 than the current yield, I agree with using a forecasted rate as well as with the
19 use of Value Line betas and a historical arithmetic average. Hence, my only
20 modification to his CAPM other than to take financial leverage into account is
21 to calculate the CAPM-based cost of equity using the lowest risk-free rate other
22 than Mr. Ufolla’s; namely the 4 percent suggested by Mr. Bandyk. This results
23 in an increase in the CAPM-based ROE of 15 basis points.

⁵⁸ Walters Testimony, pp. 45-46.

⁵⁹ Duff & Phelps recommend using their MRP with the higher of the normalized risk-free rate and the current risk-free rate. Mr. Walters implement the use of the current risk-free rate as the average over the most recent 13 weeks.

⁶⁰ Bandyk Testimony, Workpapers, tab “CAPM.”. Both Kroll and Damodaran report several versions of the MRP as explained below.

⁶¹ Bandyk Testimony, p. 17.

⁶² Bandyk Testimony, Workpapers, tab “CAPM.”

1 **Q22. Do you have any comments on Mr. Coppola's CAPM implementation?**

2 A22. I agree that Mr. Coppola's inputs to the CAPM are reasonable and suggest no
3 modifications other than to take financial leverage into account.

4 **Q23. What are your views on Mr. Walters' CAPM implementation?**

5 A23. First, it is imperative that betas reflect the best current estimate of the systematic
6 risk. Therefore the historic average of betas from 2014 to present are simply
7 not relevant. Of note, 2014 betas reflect market data for the period 2009-2014,
8 while the 2015 data reflect market data for the period 2010-2015, etc. Thus,
9 some years are over-represented, while current data are included only once.
10 The reliance on historic betas downward biases his CAPM results by 0.41
11 percent to 1.36 percent.⁶³ Consequently, rather than the average 10.39 percent
12 Mr. Walters finds, a more representative CAPM estimate using Mr. Walters'
13 data is 10.67 percent.⁶⁴ Second, regarding the S&P Global Intelligence betas,
14 the document relied upon⁶⁵ clearly shows that it is fundamental to unlever and
15 relever the betas to take into account DTE Electric's capital structure and that
16 the data relied upon to obtain the asset beta are market values. Thus, the
17 document looks to the same approach as I have. Mr. Walters fails to take that
18 into account when implementing his CAPM based on the S&P Global
19 Intelligence betas and therefore downward biases his CAPM results.

20 **Q24. What are your reactions to Mr. Bandyk's CAPM implementation?**

21 A24. I have two concerns with Mr. Bandyk's CAPM. First, he relies on an
22 exceptionally low MRP and second, there are some inconsistencies in the use
23 of his sources. For example, Mr. Bandyk uses the recommended MRP from

⁶³ Walters Testimony, WP-8, Tab AB-18 p. 1 with the 0.41 percent determined as the minimum difference between the Historical Beta and the Current S&P Global Market Intelligence Beta and the 1.36 percent determined as the maximum of the difference between the Current Beta and the Historical Beta.

⁶⁴ Determined as the average of the results using current VL betas and current MI betas from Table CCW-8, tab AB-18.

⁶⁵ Walters Exhibit CCW Confidential WP 22, tab "Instructions."

1 Kroll, but fails to acknowledge that Kroll states that this MRP should be used
2 with the higher of the current risk-free rate and that recommended by Kroll.⁶⁶
3 Thus, if Mr. Bandyk wants to use the Kroll MRP, he needs to combine that with
4 the current risk-free rate; e.g., 4.57 percent as calculated by Mr. Walters or the
5 end-of-July reported market yield on U.S. Treasury Securities at 20-Year
6 maturity of 4.56 percent.⁶⁷

7 Mr. Bandyk takes issue with my historic MRP saying that historic estimates are
8 flawed because they are “extremely sensitive to the historical time period
9 selected” and are “subject to the problem of survivorship bias.”⁶⁸ Instead, he
10 estimates his own MRP based on three sources. There are several issues with
11 this approach. Most glaringly, Mr. Bandyk relies on *Kroll*’s normalized MRP
12 of 5.0 percent, but he fails to mention that the normalized MRP is derived using
13 *historic* data. This is completely contradictory to the arguments he levies
14 against my historic MRP values. Even then, he fails to note that *Kroll*
15 recommends using the MRP in combination with a normalized risk-free rate,
16 which is the higher of 3.5 percent or the spot yield.⁶⁹ Using the spot-yield on
17 the 20-year U.S. Treasury yield of 4.57 percent would increase Mr. Bandyk’s
18 ROE estimates by close to 60 basis points.⁷⁰

19 Next, Mr. Bandyk also relies on Damodaran’s implied risk premium derived
20 MRP. This MRP is about 90 bps below any other suggested MRP,⁷¹ but it relies
21 on a very short period (12 months in the case of the model used by Mr.
22 Bandyk)⁷² to assess the cash payout to shareholders and assumes this is

⁶⁶ Kroll, “Kroll Lowers its Recommended U.S. Equity Risk Premium to 5.0%, Effective June 5, 2024,” June 6, 2024, p. 5.

⁶⁷ Walters Testimony, p. 45. Federal Reserve, FRED; [Treasury Constant Maturity | FRED | St. Louis Fed \(stlouisfed.org\)](https://fred.stlouisfed.org/)

⁶⁸ Bandyk Testimony, p. 15.

⁶⁹ See footnote 66.

⁷⁰ Federal Reserve, FRED; [Treasury Constant Maturity | FRED | St. Louis Fed \(stlouisfed.org\)](https://fred.stlouisfed.org/)

⁷¹ Mr. Ufolla uses 6.80%, Mr. Coppola uses 7.17%, Mr. Walters uses 5.00%, 7.17% and 8.45% while Villadsen Direct Testimony presented a range of 6.37% to 7.17%.

⁷² The 4.11% cited by Mr. Bandyk is consistent with Professor Damodaran’s figures for the 12-month trailing ERP ; Damodaran Online, <https://pages.stern.nyu.edu/~adamodar/>.

1 representative for the going forward period. Of note, Professor Damodaran's
2 July 2024 Smoothed ERP is 5.91 percent or 1.80 percent higher than the MRP
3 Mr. Bandyk chooses from the Damodaran website.⁷³ Finally, he relies on an
4 MRP estimate from the 2023 IESE Business School survey. Survey data can be
5 problematic and should not be considered. A study by Professor Ibbotson noted:

6 When using this [survey] method, one attempts to obtain the
7 estimates from the market participants themselves. But there are a
8 number of problems with this approach. Most of these investors have
9 no clear opinion about the long-run outlook. Many of them have only
10 very short-term horizons. Individual investors often exhibit extreme
11 optimism or pessimism and make pro-cyclical forecasts... (notes
12 omitted)⁷⁴

13 Professor Ibbotson goes on to note the problems with replicability, the
14 determination of the horizon over which the forecast is made, and the very large
15 variation in forecasts among participants. I concur and find for these reasons
16 that surveys lack reliability. Taken together, Mr. Bandyk's MRP estimate has
17 numerous problems that downwardly bias his ROE estimates to below almost
18 every CAPM estimate put forth by any witness in this proceeding. Simply put,
19 Mr. Bandyk's CAPM estimates should not be given any weight by the
20 Commission.

21 To account for the downward bias in Mr. Bandyk's CAPM, I implemented it
22 using Staff's MRP of 6.80 percent for a modified CAPM of 10.33 percent⁷⁵ and
23 very much in line with the results obtained by other witnesses.

⁷³ Comparing the Damodaran MRP cited in Bandyk Workpapers U-21534 to that on the Damodaran website (see footnote 72).

⁷⁴ Roger G. Ibbotson, "The Equity Risk Premium," *Rethinking the Equity Risk Premium*, Research Foundation of CFA Institute, December 2011, p. 20

⁷⁵ From Bandyk workpaper. Calculated as $4\% + 0.93 * 6.8\% = 10.33\%$.

II.B.2.a. Staff and Intervenors' Critiques of Villadsen CAPM⁷⁶

Q25. Mr. Walters states that you fail to consider a more normalized estimate of beta.⁷⁷ How do you respond?

A25. Like Mr. Ufolla, Mr. Coppola, and Mr. Bandyk, I rely on Value Line betas (as is common in state and federal proceedings; including in Michigan). While I agree that the COVID-19 pandemic resulted in substantial volatility in financial markets during the early part of the pandemic,⁷⁸ it does not excuse the reliance on outdated betas from 2014 to today as Mr. Walters does. First, the pandemic has a profound impact on financial markets, so it is not evident that data from prior to the pandemic reflects current conditions. Second, the electric utility industry is in transition, so the systematic risk of electric utilities (as measured by beta) may have changed. In short, it is the current systematic risk that needs to be reflected and not an outdated measure.

Q26. Mr. Bandyk critiques your reliance on the historical arithmetic MRP.⁷⁹ How do you respond?

A26. First, all parties except Mr. Bandyk relied on a historic arithmetic average MRP. Mr. Ufolla found that to be 6.80 percent, while Mr. Coppola, Mr. Walters and I used 7.17 percent. Mr. Walters also used 5.0 percent and a forecast of 8.45 percent,⁸⁰ while my Bloomberg forecast was 6.37 percent. Thus, Mr. Bandyk's MRP is simply an outlier at 4.87 percent and I disagree with his statement that there are "methodological problems that come with extrapolating a forward ERP from historic data."⁸¹ For example, the widely used MBA text of Brealey,

⁷⁶ I have relegated a discussion of the critique of the ECAPM to an appendix as Figure 11 in the Villadsen Direct, p. 39 shows that the difference between the CAPM and ECAPM estimates range from 0 to 0.1 percent.

⁷⁷ Walters Testimony, p. 57.

⁷⁸ Walters Testimony, p. 55.

⁷⁹ Bandyk Testimony, p. 17.

⁸⁰ See Villadsen Direct, Exhibit A-14, Schedule D5.17. I also calculated the MRP using FERC's methodology for MRPs of 7.87% and 7.90%. I did not implement a CAPM using these MRP results.

⁸¹ Bandyk Testimony, p. 17.

1 Myers and Allen (2017) uses the historical average market risk premium in their
2 examples,⁸² the text of Ross, Westerfield and Jaffe (2012) notes that “We [the
3 authors] are comfortable with an estimate based on the historical U.S. equity
4 risk premium of about 7 percent...”⁸³ Among regulators the historical average
5 MRP is also common as seen here where Staff, the AG and ABATE included
6 this measure. Similarly, the Surface Transportation Board has specified the use
7 of the historical average MRP in the manner Staff, the AG and ABATE do
8 here.⁸⁴

9 II.B.3. Risk Premium Analyses

10 Q27. Do Staff or Intervenor witnesses consider the risk premium analysis?

11 A27. Yes. Mr. Ufolla, Mr. Coppola and Mr. Walters all implement one or more
12 versions of the risk premium models. Mr. Bandyk does not use a risk premium
13 model. However, Messrs. Ufolla, Coppola and Walters use slightly different
14 versions of the model. Mr. Ufolla calculates the historical spread between the
15 total return on utilities and the utility bond yield, then add this spread to the
16 long-term utility bond return. He also implements a version that relies on
17 Treasury bond yields instead of utility bond yields. Mr. Coppola similarly
18 calculates the historical spread between the return on utilities and the expected
19 A-rated utility bonds. He then adds the forecasted bond yield to the historical
20 spread. Mr. Walters implements the risk premium using the allowed ROE and
21 calculates the historical spread to both A-rated utility bonds and Treasury yields.
22 He then adds this spread to the A-rated utility bond yield / the Treasury bond
23 yield. These approaches all rely on the historical difference between the
24 realized ROE (Mr. Ufolla, Mr. Coppola) or allowed ROEs (Mr. Walters) and a
25 debt cost (Treasury bond yields or utility bond yields). These approaches fail

⁸² Brealey, Myers and Allen, *Principles of Corporate Finance*, 12th edition, 2017, pp. 164-166 and 199.

⁸³ Ross, Westerfield and Jaffe, *Corporate Finance*, 10^{ed}, 2012, p. 326.

⁸⁴ Surface Transportation Board, Decision in Docket No. EP 558 (Sub-No. 22), Aug. 5, 2019, p. 7.

1 to take into account the inverse relationship between the utilities' equity risk
2 premium and the level of interest rates.⁸⁵ Simply put, as interest rates increase
3 (decrease), the equity risk premium decreases (increases), so the risk premium
4 is not constant over time. To more accurately estimate the premium, it is
5 important to use a statistical relationship that takes the interaction of interest
6 rates and earned or authorized returns into account. Taking the arithmetic
7 average may underestimate (or overestimate) the premium and not fully reflect
8 the interaction between bond yields and earned or allowed ROEs. This is
9 particularly true if a Treasury bond yield is used during a period of substantial
10 changes in the spread between utility bonds and Treasury bond yields. At the
11 moment these considerations only seem to be a concern for Mr. Ufolla's risk
12 premium model that relies on the Treasury bond yield (and which uses a very
13 low forecasted 20-year yield). This explains the very low number Mr. Ufolla
14 finds using the Treasury bond yield.⁸⁶ Because the equity market and the
15 Treasury bond yields have moved in very different directions during part of the
16 period considered by Mr. Ufolla (1931-2023), the impact of not taking the
17 inverse relationship between interest rates and the risk premium into account is
18 magnified. The results from this model are very different from the result he
19 obtains from his risk premium model based on A-rated utility bond yields as
20 well as from that obtained by other witnesses. It is also 115 basis points below
21 Mr. Ufolla's other results (from the DCF, CAPM and A-rated utility bond risk
22 premium analysis). I therefore consider that only the results from the A utility
23 bond yields reflects the current cost of equity.

24 **Q28. Do you have any other comments on the risk premium model?**

25 A28. Yes, Mr. Bandyk refers to FERC Order 569 from 2019 as having rejected the
26 risk premium model.⁸⁷ However, this is only a partial discussion of FERC's

⁸⁵ See, for example, Roger A. Morin, *Modern Regulatory Finance*, 2021 pp. 138-139 for an analysis of this relationship between allowed ROEs and bond yields.

⁸⁶ Staff Exhibit S-4, Schedule D-5, Tab "Risk Premium" And Historical Returns - Elec

⁸⁷ Bandyk Testimony, p. 23.

1 decision-making regarding the risk premium model. Specifically, in FERC
2 Opinion No. 569-A, the FERC concluded that “the Risk Premium model, with
3 adjustments, is sound.”⁸⁸ However, the DC. Circuit Court in 2022 remanded the
4 decision back to FERC as Opinion 569-A failed to explain and address prior
5 concerns.⁸⁹ Thus, the treatment of the Risk Premium model at FERC is
6 currently undecided.

7 Second, I note that except for Mr. Ufolla’s risk premium over the Treasury bond
8 yield from 1931 to 2023, the risk premium results the witnesses obtain are very
9 similar, so I shall not address the issue further.

10 II.C. Financial Leverage Adjustments

11 II.C.1. Preliminaries

12 Q29. What do you cover in this section of your rebuttal testimony?

13 A29. I respond to the critiques and misunderstandings of my Direct Testimony
14 regarding financial leverage. Specifically, I address the concerns of Mr. Ufolla,
15 Mr. Walters, and Mr. Coppola regarding the use of various methods to account
16 for financial leverage. I also address Mr. Bandyk’s use of the average capital
17 structure for the sample companies as a benchmark for DTE Electric. In doing
18 so, I discuss the financial economics underlying the approach and the regulatory
19 precedent for taking financial leverage into account. Finally, I assess the impact
20 on the Intervenor’s failure to consider the impact of their capital structure
21 recommendations on the ROE investors require.

⁸⁸ FERC Order 569-A issued May 21, 2020, ¶46.

⁸⁹ See, for example, VanNess Feldman, “DC Circuit Court of Appeals Puts FERC’s Revised Method for ROE Determination in Question,” August 10, 2022.

1 **Q30. Please summarize Staff's and Intervenors' testimonies regarding financial**
2 **risk.**

3 A30. Collectively, Staff and Intervenors take issue with my use of an "ATWACC
4 adjustment"⁹⁰ and my reliance on the textbook Hamada method,⁹¹ although Mr.
5 Walters is confused as to the methods and results. For example, it appears that
6 Mr. Walters incorrectly believes that I use the ATWACC method to derive my
7 CAPM / ECAPM based recommendation.⁹² This led Mr. Walters to erroneously
8 claim that the financial leverage caused me to recommend a ROE up to 11.90
9 percent.⁹³ As clearly stated in Villadsen Direct, I did not rely on the after-tax
10 weighed average cost of capital method for my CAPM.⁹⁴ Specific critiques of
11 the financial risk adjustment fall into the following categories:

- 12 1. *Market vs. book value of capital structures*: Mr. Ufolla is concerned
13 about using market values in the overall cost of capital⁹⁵ and Mr.
14 Walters states that book value capital structure of DTE Electric relative
15 to the sample is the relevant comparison because DTE Electric's stock
16 is not publicly traded.⁹⁶
- 17 2. *Adjusting for leverage*: Staff does not believe the Hamada method is
18 applicable in a ratemaking environment.⁹⁷ Similarly, Mr. Coppola finds
19 the method unsuitable in a regulatory environment and also finds the
20 method leads to faulty and inflated results.⁹⁸

⁹⁰ Ufolla Testimony, p. 13; Walters Testimony, p. 61; Coppola Testimony, p. 83-85.

⁹¹ Ufolla Testimony, p. 17; Walters Testimony, pp. 61; Coppola Testimony, p. 88.

⁹² Mr. Walters' Table CCW-14 report an ECAPM (1.5%) Recommended ROE of 11.0% - 11.9%. These numbers do not appear in my direct testimony, which lists the ECAPM results as 10.8% - 11.7%. See Figure 10, p. 35 of Villadsen Direct. This also means that Mr. Walters' estimate of the financial leverage accounting for up to 90 basis points is wrong and based on data that is not relied upon in my testimony.

⁹³ Walters Testimony, Table CCW-14, p. 61. Clearly, there are no number in Villadsen Direct, Figure 10, p. 35 above 11.7%.

⁹⁴ Villadsen Direct, p. 31, footnote 65.

⁹⁵ Ufolla Testimony, p. 18.

⁹⁶ Walters Testimony, p. 63.

⁹⁷ Ufolla Testimony, p. 17.

⁹⁸ Coppola Testimony, p. 88.

1 3. *Regulatory Precedent*: Intervenor argue that the financial risk
2 adjustments lack regulatory precedent in the U.S.⁹⁹

3 4. *Sample Capital Structure*: Mr. Bandyk argues that the relevant capital
4 structure to adjust towards is the average market value capital structure
5 of the sample.¹⁰⁰

6 **Q31. How do you respond to Staff's and Intervenor's' assertion that leverage**
7 **adjustments are inappropriate and investors should only be compensated**
8 **for capital invested in plant and equipment?**

9 A31. First, the leverage adjustment does not compensate for anything other than
10 capital invested in plant and equipment. There is no change to the amount of
11 capital earning a return – it is simply the equity portion of the rate base. Second,
12 all Intervenor use publicly traded utilities when performing their DCF analysis
13 and to estimate the Market Risk Premium used in their CAPM analysis. These
14 publicly traded companies vary in their capital structure – the amount of debt
15 and equity the company holds. Therefore, Intervenor and I are all using market
16 values in our analyses; the difference is how we use market values to adjust for
17 financial leverage.

18 Both the CAPM and DCF models rely on market data to estimate the cost of
19 equity for sample companies, so the results reflect the value of the capital that
20 investors hold during the estimation period (market values). The allowed return
21 on equity is applied to the rate base, which is determined using the historical
22 cost and hence reflects the net book value of assets. Taking differences in
23 financial leverage into consideration **does not** change the value of the rate base
24 and consequently does not depart from original cost ratemaking principles.
25 Adjustment for differences in leverage does consider the fact that the more debt
26 a company has, the higher the financial risk associated with an equity
27 investment in that company. Furthermore, the higher risk to investors will

⁹⁹ Ufolla Testimony, pp. 17-18; Walters Testimony, p. 64-65.

¹⁰⁰ Bandyk Testimony, Workpapers, tab "Hamada Beta."

1 increase the cost of equity capital raised through primary investing to fund
2 investments in plant and equipment to serve ratepayers.

3 **Q32. How should capital structure be considered to ensure that the allowed**
4 **returns meet the fair return standard?**

5 A32. The proportion of debt in the capital structure—also known as financial
6 leverage—influences the risk borne by equity investors. For a given degree of
7 business risk, a higher proportion of debt financing increases the expected
8 variability of equity returns. Thus, to compare the fair returns of two otherwise
9 identical firms, on a risk adjusted basis, the capital structures must be taken into
10 account. For example, if more debt is used, the greater financial risk imposed
11 by the greater financial leverage must be compensated by a commensurately
12 higher expected return on equity. Otherwise, the more leveraged firm will not
13 receive a fair return and will be at a disadvantage in the competition to attract
14 capital in equity markets.

15 **Q33. How does leverage relate to the cost of equity?**

16 A33. Financial risk or capital structure is a large topic in financial economics. The
17 principle that financial leverage amplifies the variability of equity returns and
18 thereby increases the financial risk to equity investors is a firmly established
19 core principal of corporate finance. It is directly connected to the Modigliani
20 Miller proposition that, except as influenced by the tax-deductibility of debt and
21 the cost of financial distress, the value of a firm's assets is independent of its
22 choice of financing. This intuitive framework means that some measures of the
23 overall cost of capital for firms with comparable systematic business risk should
24 be the same regardless of capital structure,¹⁰¹ even if the cost of the equity
25 and/or debt components of financing vary in proportion to the degree of
26 financial leverage.

¹⁰¹ Except in cases of extremely high or low leverage, where the tax and financial distress effects may dominate.

1 It is commonly recognized in finance textbooks that financial leverage impacts
2 the cost of equity for a company. A replication from a standard MBA textbook
3 is provided below:¹⁰²

COMMON MISTAKE Is Debt Better Than Equity?

Because debt has a lower cost of capital than equity, a common mistake is to assume that a firm can reduce its overall WACC by increasing the amount of debt financing. If this strategy works, shouldn't a firm take on as much debt as possible, at least as long as the debt is not risky?

This argument ignores the fact that even if the debt is risk free and the firm will not default, adding leverage

increases the risk of the equity. Given the increase in risk, equity holders will demand a higher risk premium and, therefore, a higher expected return. The increase in the cost of equity exactly offsets the benefit of a greater reliance on the cheaper debt capital, so that the firm's overall cost of capital remains unchanged.

4
5 As Professors Berk and DeMarzo further note:

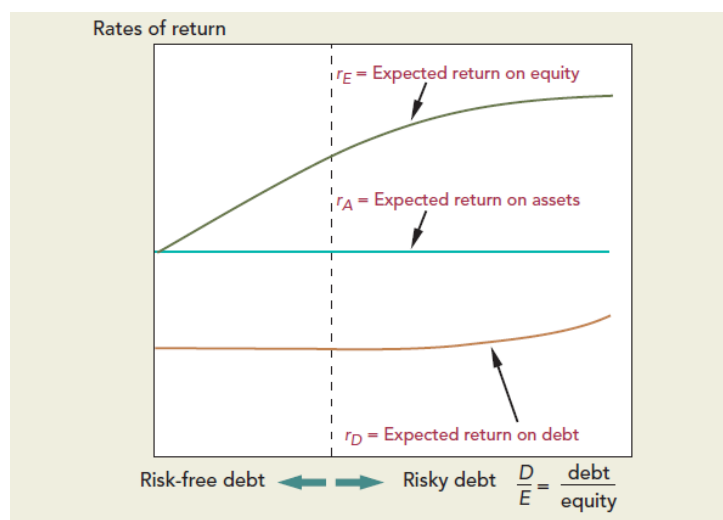
6 The levered equity return equals the unlevered return, plus an extra
7 “kick” due to leverage...The amount of additional risk depends on
8 the amount of leverage, **measured by the firm's market value**
9 **debt-equity ratio, D/E...**¹⁰³ (emphasis added)

10 This relationship is further illustrated in Figure 1 reproduced from the seminal
11 textbook *Principles of Corporate Finance* by Brealey, Myers, and Allen. It
12 illustrates that as capital structure shifts to use a greater proportion of lower cost
13 debt financing, the investor required return on equity (and debt, especially at
14 higher leverage ratios) increases to compensate for the greater financial risk,
15 such that the overall required return on assets remain unchanged.

¹⁰² Jonathan Berk and Peter DeMarzo, “Corporate Finance,” Third Edition, 2013 (Berk & DeMarzo 2013), p. 492.

¹⁰³ Berk & Peter DeMarzo 2013, p. 489. Similar comments appear in Richard A. Brealey, Stewart C. Myers, and Franklin Allen, 2014, *Principles of Corporate Finance*, 11th edition, McGraw-Hill Irwin (Brealey, Myers & Allen 2014), p. 433.

FIGURE 1: ILLUSTRATION OF THE MODIGLIANI MILLER PRINCIPLE¹⁰⁴



Financial economics textbooks leave no doubt that the cost of equity increases with financial leverage and that the relevant measure of financial leverage depends on market value. I—like other witnesses—estimate the cost of equity using market data in the CAPM and DCF-based models. Since the Risk Premium model is based on book values, the relevant leverage for this methodology is book value based.

Q34. Do you agree with Mr. Bandyk’s adjustment towards the average of the sample?¹⁰⁵

A34. No. I firmly disagree. The capital structure at which DTE Electric receives a rate of return is not the average of the sample, but the regulatory capital structure of 50 percent. Surprisingly, Mr. Bandyk did not even look towards the capital structure of DTE Electric’s parent company, DTE Energy, which has a lower market value equity percentage than the sample at about 56 percent.¹⁰⁶ The

¹⁰⁴ Brealey, Myers, and Allen, *Principles of Corporate Finance*, 10th Ed. (2011), p. 429, Figure 17.2.

¹⁰⁵ Bandyk Testimony, Workpapers, tab “Hamada Beta.”

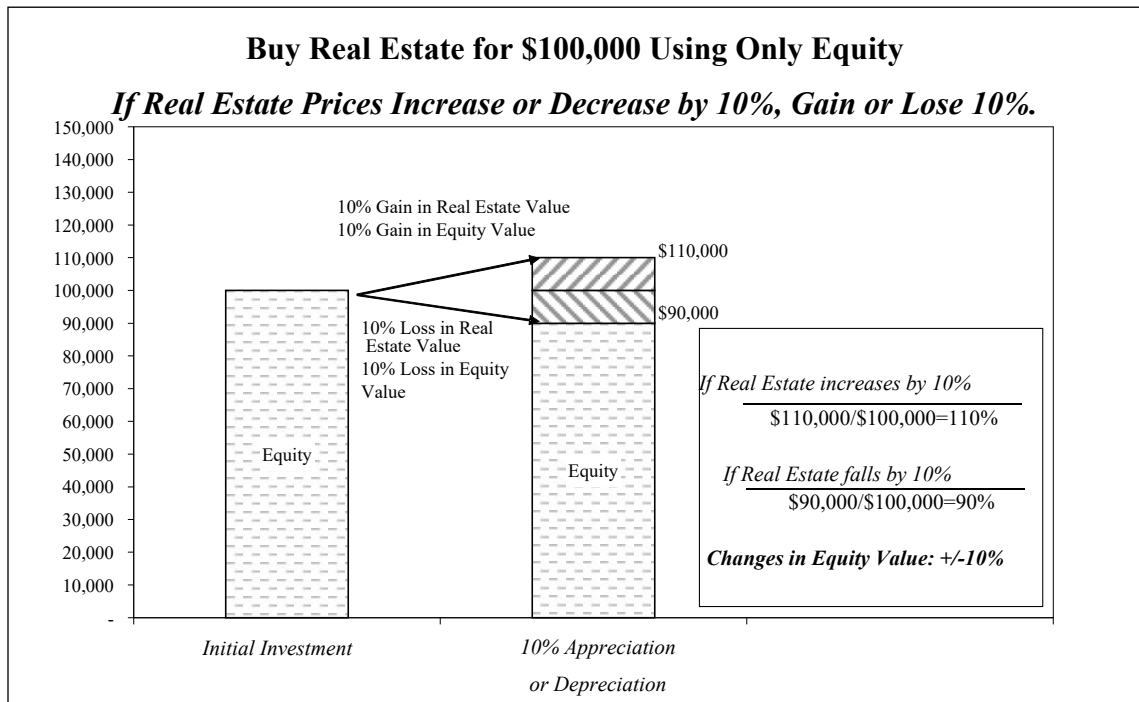
¹⁰⁶ Exhibit A-39, Schedule DD8.

impact hereof would be to increase the CAPM cost of equity estimated by Mr. Bandyk by 13 basis points.¹⁰⁷

Q35. Could you provide a numerical example to illustrate the impact of financial leverage on cost of equity?

A35. Yes. As a simple example, think of an investor who takes money out of her savings and invests \$100,000 in real estate. The future value of the real estate is uncertain. If the real estate market booms, she will realize a gain. However, if the real estate market declines, she will realize a loss. Figure 2 below provides an illustration of this:

FIGURE 2: RETURN ON AN ALL EQUITY INVESTMENT

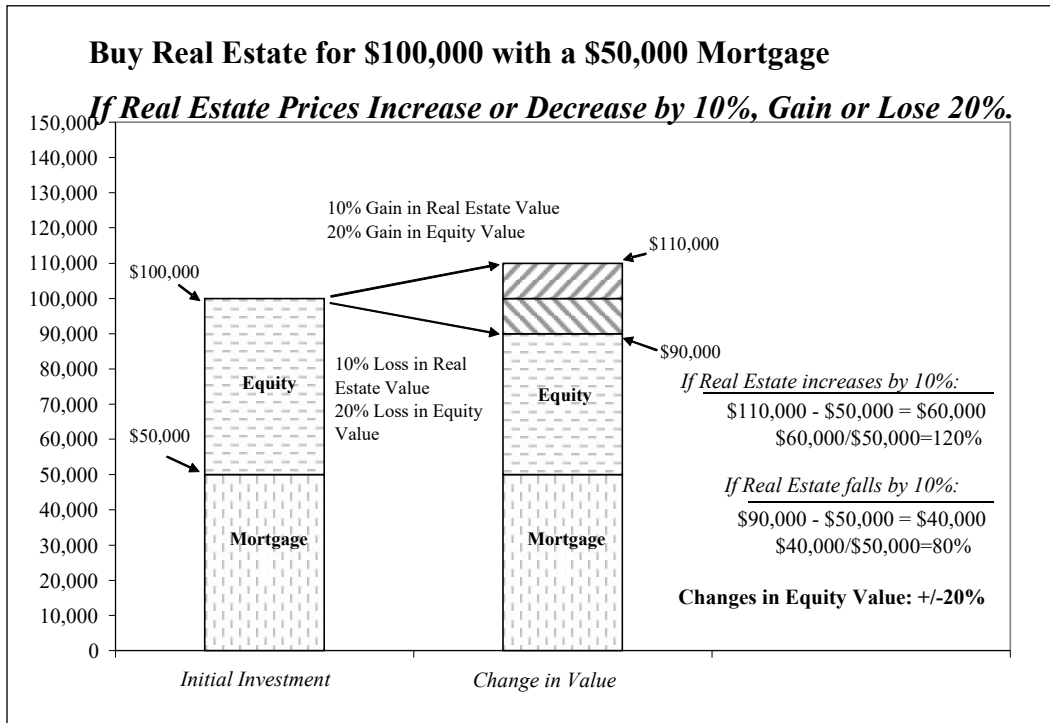


Compare this to the situation illustrated in Figure 3 below, where the investor finances the same real estate purchase using 50 percent cash from her savings (equity) and finances 50 percent using funds from a mortgage (debt). In this

¹⁰⁷ To see this, I simply compared the results in Bandyk Testimony, Workpapers tab "CAPM" with those obtained, when changing the equity percentage in tab "Hamada Beta" to 56%. See Exhibit A-39, DD9.

case, the variability in the investor's expected equity return is two-times greater than in Figure 2. The entire fluctuation of 10 percent from rising or falling real estate prices falls on the investor's equity investment, which is smaller (\$50,000) for the leveraged investment depicted in Figure 3 as compared to the all-equity \$100,000 investment shown in Figure 2. The equity return for the leveraged investment goes up or down by 20 percent in the leverage scenario even though the actual change in the value of the real estate (+/- 10 percent) is the same as depicted in Figure 2 for the all-equity investment. The lesson from this example is obvious: debt adds risk because, while there is more potential gain on the equity investment by using debt, there is a higher potential loss on that equity investment that goes with it. This concept is colloquially referred to as "high risk, high reward."

FIGURE 3: RETURN ON A LEVERAGED EQUITY INVESTMENT



1 **Q36. Do finance textbooks also address the question of how financial leverage**
2 **affects the cost of equity?**

3 A36. Yes. Standard textbooks on corporate finance provide examples, like the one I
4 presented above, to illustrate how the introduction of debt financing amplifies
5 the variability of equity returns and thus increasing the risk to equity holders
6 which causes them to demand higher expected returns. For example, Professors
7 Brealey, Myers, and Allen write:

8 Our example shows how borrowing creates financial leverage or
9 gearing. Financial leverage does not affect the risk or the expected
10 return on the firm's assets, but it does push up the risk of the
11 common stock. Shareholders demand a correspondingly higher
12 return because of this *financial risk*.¹⁰⁸

13 Similarly, Professors Berk and DeMarzo summarize the effect of leverage on
14 the cost of capital as follows:

15 [L]everage increases the risk of equity even when there is no risk
16 that the firm will default. Thus, while debt may be cheaper when
17 considered on its own, it raises the cost of capital for equity.
18 Considering both sources of capital together, the firm's average cost
19 of capital with leverage is ... the same as for the unlevered firm.¹⁰⁹

20 These statements by preeminent finance scholars in widely-used Corporate
21 Finance textbooks highlight two important points that can also be intuitively
22 observed based on the real estate investment example:

- 23 ► The variability of returns on the asset itself (*e.g.*, the piece of real estate) is
24 unchanged by the introduction of financial leverage, therefore “leverage

¹⁰⁸ Brealey, Myers and Allen (2017), *Principles of Corporate Finance*, 12th Edition, p. 446 (emphasis in original).

¹⁰⁹ Berk and DeMarzo (2014), *Corporate Finance*, 3rd Ed., p. 482 (emphasis in original).

1 does not affect the risk or the expected return on the firm's assets." Rather,
2 it is the risk and required returns of the equity and debt financing
3 instruments that are changed by the degree of financial leverage.

- 4 ► The mechanism by which leverage adds variability to returns is
5 independent of any effect of increased leverage on the risk that the firm
6 will be unable to fulfill its fixed financial obligations, and thus (as Berk
7 and DeMarzo put it) "leverage increases the risk of equity even when there
8 is no risk that the firm will default."

9 **Q37. Do financial economists recognize the calculation of after-tax weighted-**
10 **average cost of capital based on market values?**

11 A37. Yes. Looking to the most widely-used MBA textbook by Professor Brealey,
12 Myers, and Allen, they explain that:

13 The formula for the after-tax weighted average cost of capital is¹¹⁰:

14
$$WACC = r_D(1 - TC) \left(\frac{D}{V} \right) + r_E \left(\frac{E}{V} \right)$$

15 where r_D and r_E are the expected rate of return demanded by investors in the
16 firm's debt and equity securities, D and E are the current market values of debt
17 and equity and V is the total market value of the firm ($V = D + E$).¹¹¹

18 Professors Brealey, Myers, and Allen then show that the after-tax weighted
19 average cost of capital is flat over a broad range of capital structures and
20 calculates the cost of equity using the same formula as I do.¹¹²

21 **Q38. Do financial economists recognize the Hamada technique?**

22 A38. Yes. The Technical Appendix (Appendix B) to my direct testimony provides a
23 detailed description of the standard textbook formulas used to implement the
24 Hamada technique for unlevering measured equity betas based on the proxy

¹¹⁰ This specification ignores preferred shares, but such financing could easily be added.

¹¹¹ Brealey, Myers and Allen (2014), p. 492.

¹¹² *Ibid.*

1 companies' capital structure to calculate "asset betas" that measure the proxy
2 companies' business risk independent of the financial risk imposed by differing
3 capital structures. I also note that standard MBA textbooks,¹¹³ practitioner
4 texts,¹¹⁴ as well as the certified financial analyst (CFA) curriculum¹¹⁵ all
5 describe the Hamada approach and use formulas like those relied upon in my
6 direct testimony. Thus, the Hamada method is simply a well-established
7 methodology taught in business schools as well as to CFA applicants.

8 **Q39. What are the implications of these fundamental financial principles for the**
9 **Intervenors' ROE results?**

10 A39. Failing to recognize the impact of financial leverage on the cost of equity results
11 in a downward bias in the cost of equity estimates. For example, the failure to
12 recognize financial leverage downward biases the cost of equity by
13 approximately 50-70 basis points.¹¹⁶

14 This approach is exactly as described in standard textbooks such as Brealey,
15 Myers and Allen (2014), Berk and DeMarzo (2014), and Ross, Westerfield and
16 Jaffe (2013) and the CFA curriculum,¹¹⁷ of which Mr. Walters is a charterholder.

¹¹³ Brealey, Myers and Allen (2014), pp. 492–493, Berk and DeMarzo (2014) pp. 415–417, Ross, Westerfield and Jaffe (2013), pp. 571–573.

¹¹⁴ Roger A. Morin, "New Regulatory Finance," Public Utilities Reports, Inc., 2006, pp. 221–225; Leonardo R. Giacchino and Jonathan A. Lesser, "Principles of Utility Corporate Finance," Public Utilities Report, Inc., 2011, pp. 229–232.

¹¹⁵ See, for example, 2016 CFA Level I Volume 4: Corporate Finance and Portfolio Management, Chapter 4.

¹¹⁶ Comparing the Ufolla Testimony's CAPM without Hamada (p. 18) to my estimates results in a leverage impact of 0.64% to 0.72%, the Coppola Testimony p. 89 estimates the impact to be 70 basis points. This is consistent with my estimate of approximately 75 basis points (when taxes are considered in Exhibit A-39, Schedule DD11. The Walters Testimony p. 61 finds a leverage impact of 0.50% to 0.90% with the upper end of this improperly being based on data that did not impact my recommendation as explained above.

¹¹⁷ Brealey, Myers and Allen (2014), pp. 492–493, Berk and DeMarzo (2014) pp. 415–417, Ross, Westerfield and Jaffe (2013), pp. 571–573. 2016 CFA Level I Volume 4: Corporate Finance and Portfolio Management, Chapter 4. In all cases, they apply the Hamada method to the market value capital structure.

Q40. What do you conclude from the discussions above?

A40. I conclude that Staff's and Intervenor's ROE estimates are downwardly biased because they fail to account for the impact of financial leverage on the cost of equity, using standard financial techniques. Importantly, Mr. Coppola, Mr. Ufolla and Mr. Walters' results are in line with those I determined once financial leverage is taken into consideration. I also note that Mr. Bandyk, who does consider financial leverage important, obtains results in the range of 10.3 percent with an appropriate MRP. As noted above, I only consider the Hamada approach applied to the CAPM models of Staff and Intervenor's. Once appropriate modifications are made, as shown in Table 2 above, and the fact that DTE Electric has lower equity than what is represented in the proxy company data used to estimate the cost of equity is taken into account, both Staff's and Intervenor's modified results are consistent with a ROE of 10.50 percent.

II.C.2. Regulatory Decisions

Q41. Does adjusting for financial leverage have regulatory precedent?

A41. Yes. Multiple regulatory agencies in the U.S. and most outside of North America have adopted a similar approach. In the U.S., the Federal Communications Commission (FCC), the Surface Transportation Board (STB), and the FERC have accepted the use of weighted-average cost of capital methodologies to determine the cost of capital. Specifically, the FCC in a 2016 order acknowledged that it is reasonable (1) to use market values to estimate the capital structure and (2) derive an implied return on equity from the estimated weighted average cost of capital.¹¹⁸ Thus, the FCC acknowledged that market value capital structures are the relevant measure of leverage and impact the ROE using an approach similar to what I used. The FERC, in Cost

¹¹⁸ Federal Communications Commission, "Report and Order, Order and Order on Reconsideration, and Further Notice of Proposed Rulemaking," FCC 16-33, issued March 30, 2016, ¶270 and ¶322.

1 of New Entry (CONE) studies for the Pennsylvania, New Jersey and Maryland
2 (PJM),¹¹⁹ has used the weighted average cost of capital. The STB calculates the
3 weighted average cost of capital to assess the revenue adequacy for freight
4 railroads.¹²⁰ Considering next the Hamada approach, I note that the California
5 Public Utilities Commission in the past has relied on results from the method,¹²¹
6 the Oregon Public Service Commission staff commonly relies on a version of
7 the Hamada method to assess the impact of leverage on the cost of equity,¹²²
8 and the Florida Public Service Commission uses an equivalent methodology to
9 determine the ROE for small water utilities.¹²³

10 Looking outside the U.S., Mexico's *Comisión Reguladora de Energía*¹²⁴ relies
11 on the Hamada method, while regulators in the U.K., the Netherlands, Australia,
12 and New Zealand rely on a mixture of an after-tax weighted average cost of
13 capital and the Hamada method.¹²⁵ Of note, the British Columbia Utilities
14 Board in a recent decision acknowledged that

¹¹⁹ Federal Energy Regulatory Commission, "Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing," Docket ER14-2940-000, November 28, 2014, ¶59. See also, Federal Energy Regulatory Commission, "Order Accepting Proposed Tariff Revisions," Docket ER19-105-001, ER19-105-002, April 15, 2019, and ER-19-105-004, April 16, 2020.

¹²⁰ See, for example, Surface Transportation Board, "Docket No. EP 558 (Sub-No. 22), dated August 5, 2019, p. 15.

¹²¹ The California Public Utilities Commission ("CPUC") relied on Hamada unlevered / relevered data in D.12-12-034 at 38. Here the CPUC pointed to Southern California Edison's CAPM results and ROE range of 9.73 percent to 11.71 percent, which was derived using the Hamada method.

¹²² Opening Testimony of Matt Muldoon in Docket No. UE 319, Staff Exhibit 500, p. 15.

¹²³ Florida PUC for water and wastewater utilities (Order No. PSC-12-0339-PAA-WS); "Florida 2012 Order"), p. 4.

¹²⁴ CRE, "Directiva sobre la determinación de tarifas y el traslado de precios para las actividades reguladas en materia de gas natural DIR-GAS-001-2207."

¹²⁵ Villadsen, Bente, *et al*, "Risk and Return for Regulated Industries," Academic Press, 2017, Chapter 9 and references herein.

1 there is a need to account for leverage differences in the proxy group
2 of companies and acknowledges that the Hamada adjustment is an
3 appropriate approach to adjust...¹²⁶

4 **Q42. What do you conclude?**

5 A42. Several regulatory entities have found the methods used in financial economics
6 to consider leverage useful and all methods I use are well accepted, standardly
7 taught in corporate finance classes. A very recent acceptance was the British
8 Columbia Utilities Commission 2023 order that acknowledged the Hamada
9 approach. The methods are also standard curriculum in finance textbooks and
10 commonly used by practitioners who provide cost of capital measures.¹²⁷

11 **II.D. Other Arguments Regarding the Level of the ROE**

12 **Q43. Are there other topics you want to address regarding Intervenors' cost of**
13 **equity analysis?**

14 A43. Yes. I will address Mr. Bandyk's perception that

15 There is strong evidence from multiple observers and peer-reviewed
16 academic research that public regulatory commissions on average
17 have tended to set electric utility ROEs above what objective

¹²⁶ British Columbia Utilities Board, "Generic Cost of Capital Proceeding (Stage 1), Decision and Order G-236-23," issued September 5, 2023.

¹²⁷ For an example of a commercial data provider's application, see Duff & Phelps, "2018 Valuation Handbook—U.S. Guide to Cost of Capital," Chapter 1 pp. 1–21 For examples of tax authorities applications, see, for example, Utah Rule R884-24P-62 "Valuation of State Assessed Unitary Properties Pursuant to Utah Code Ann. Section 59-2-201," which states "The discount rate (k) shall be based upon a weighted average cost of capital (WACC) considering current market debt rates and equity yields." (<https://rules.utah.gov/publicat/code/r884/r884-24p.htm#T32>)

I understand it is common for taxes based on net present values to use a market value based after-tax weighted-average cost of capital as the discount rate.

1 observers in the financial community would arrive at using the
2 widely-accepted methods for estimating ROE.¹²⁸

3 I will also address the use of credit ratings, allowed and earned returns.

4 **Q44. What is your reaction to Mr. Bandyk's statement that regulatory utility**
5 **commissions set the allowed ROE above the cost of equity?**

6 A44. I disagree. Certainly, many commissions explicitly state that they set the
7 allowed ROE at the cost of equity. Thus, while there is some statistical
8 uncertainty surrounding the estimation of the cost of equity and some subjective
9 judgement by commissions, the statement would imply that Mr. Bandyk
10 believes the commissions consistently fail to set an appropriate ROE. To this
11 end, I note that there are voluminous records confirming that the regulatory
12 intent and policies are to set allowed ROE at the market cost of equity. The
13 legal standard for setting the ROE can be traced back to the Supreme Court's
14 1944 decision in *Hope*:

15 The rate-making process under the Act, i.e., the fixing of 'just and
16 reasonable' rates, involves a balancing of the investor and the
17 consumer interests...The return to the equity owner should be
18 commensurate with returns on investments in other enterprises
19 having corresponding risks. That return, moreover, should be
20 sufficient to assure confidence in the financial integrity of the
21 enterprise, so as to maintain its credit and to attract capital.¹²⁹

22 The broad language of the *Hope* decision allows a variety of specific
23 interpretations of the standard. However, since the 1970s it has become
24 customary to interpret the standard to be consistent with finance theory, which

¹²⁸ Bandyk Testimony, p. 6.

¹²⁹ Supreme Court Decision on *Hope*, 320 U.S. at 603.

1 defines the “commensurate return” as the rate of return investors expect
2 (**forward-looking**) when they buy stocks of comparable risk. This is a **market**
3 cost of equity that is closely related to the economic concept of **opportunity**
4 **cost**: a regulated utility must offer stock investors returns that are comparable
5 to that of other firms—regulated or not—that face similar financial risks.¹³⁰

6 Regulation is usually regarded as a substitute for competition. If the definition
7 of “fair return” is based on the theory of competitive markets, then regulation
8 should assure that the average expected rate of return on new utility investment
9 is equal to the utility’s cost of capital. That is the ultimate justification for
10 basing rate of return regulation on finance theory.¹³¹

11 **Q45. What is your view on using credit ratings and credit ratings reports to**
12 **determine the cost of equity?**

13 A45. Mr. Walters and Dr. Stults refer to credit ratings and the access to capital.¹³²
14 However, in doing so, they conflate the attraction of debt and equity capital –
15 credit ratings measure credit risk, while equity investors are considering the
16 return that is available on alternative investments of similar equity risk. The
17 fact that DTE Electric has maintained its credit rating and is able to attract debt
18 capital does not imply that the allowed ROE is commensurate with returns on
19 investments in other enterprises having corresponding risks. Because bond
20 holders absent default receive a fixed return on their investment, while equity
21 investors are exposed to variability in market returns, the risk to equity investors
22 is not only higher but different. Consequently, the statement by Fitch in 2023
23 that DTE Electric’s authorized ROE “compares favorably with industry
24 averages”¹³³ simply means that it was higher than the average and that Fitch did
25 not see an issue with DTE Electric’s creditworthiness. Similarly, Mr. Walters

¹³⁰ Professor Stewart C. Myers’s paper, “The Application of Finance Theory to Public Utility Rate Cases,” *Journal of Economics and Management Science* 3, 1972 pp. 58-97 (“Myers (1972)”), was seminal in bringing finance theory into public utility regulation.

¹³¹ Myers (1972), at p. 94.

¹³² Walters Testimony, pp. 18-19. Stults Testimony, pp. 9-13.

¹³³ Stults Testimony, p. 11.

1 cites to Moody's and Fitch regarding concerns related to consumer affordability
2 and acknowledges that Moody's has changed its outlook for the industry from
3 Positive to Negative, while Fitch sees the outlook as "deteriorating" for North
4 American utilities.¹³⁴

5 I note that S&P defines credit ratings as "opinions about credit risk... the
6 agency's opinion about the ability and willingness of an issuer... to meet its
7 financial obligation in full and on time."¹³⁵ Further, S&P states: "Credit ratings
8 ... are not indications of investment merit...the ratings are not buy, sell, or
9 hold... or a measure of asset value... they speak to one aspect of an investment
10 decision – credit quality..."¹³⁶ Therefore, Dr. Stults' and Mr. Walters' assertion
11 that DTE Electric's credit rating has implications for the riskiness of its ROE is
12 unfounded.

13 **Q46. How about Dr. Stults' discussion that DTE Electric delivers "premium**
14 **shareholder returns"?**¹³⁷

15 A46. There are two problems with this statement. First, Dr. Stults is discussing DTE
16 Energy and not DTE Electric, which violates the stand alone principle. Second,
17 Dr. Stults is focused on historical events, whereas the cost of equity is a
18 forward-looking concept. As stated by Professors Brealey, Myers and Allen in
19 their widely used MBA text

20 the cost of equity (the **expected rate of return** demanded by
21 investors in the firm's common stock).¹³⁸ [Emphasis added]

¹³⁴ Walters Testimony, pp. 18-19.

¹³⁵ S&P Global Ratings, "Guide to Credit Rating Essentials What are credit ratings and how do they work?" 2019, p. 4, https://www.spglobal.com/ratings/_division-assets/pdfs/guide_to_credit_rating_essentials_digital.pdf

¹³⁶ S&P Global Ratings, "Guide to Credit Rating Essentials What are credit ratings and how do they work?" 2019, p. 5, https://www.spglobal.com/ratings/_division-assets/pdfs/guide_to_credit_rating_essentials_digital.pdf

¹³⁷ Stults Testimony, p. 13.

¹³⁸ Brealey, Myers and Allen, Principles of Corporate Finance, 11'th Edition, 2014, p. 221.

1 Thus, Dr. Stults is not addressing the cost of equity in these statements.

2 **Q47. What is your view on Ms. Perry’s reliance on recently allowed ROEs as**
3 **indicators of the cost of equity for DTE Electric?**

4 A47. Recently allowed ROEs are relevant for purposes of comparability and I use
5 such data in my risk premium analysis. However, it is important, to consider
6 the context in which such returns were allowed, as I do in my risk premium
7 analysis. Ms. Perry focuses on recently allowed ROEs in Michigan and
8 nationwide to suggest that the Company’s requested ROE “is excessive.”¹³⁹
9 For example, the average allowed return on equity for integrated electric
10 utilities in 2024 for Q1 and Q2 is 9.75 percent and for 2023 the authorized ROE
11 was 9.80. However, it is important to recognize that on average electric utilities
12 have been awarded a higher equity percentage than what DTE Electric is
13 requesting. For example, the average allowed equity percentage was 51.15
14 percent for 2023.¹⁴⁰ Thus, the 9.75 or 9.80 percent are downward biased in that
15 the average utility has a higher equity percentage and hence weigh the equity
16 more in the overall cost of capital that customers pay. Additionally, it is
17 necessary to consider whether there are risk factors for DTE Electric that merit
18 a higher or lower return on equity than those granted other integrated electric
19 utilities. Of note, DTE Energy, the parent of DTE Electric, has approximately
20 45 percent coal generation - - indicating a high level of dependence on fossil
21 fuels and a need for substantial capital investments to transition to less carbon
22 intensive generation.¹⁴¹

¹³⁹ Perry Testimony, p. 9.

¹⁴⁰ Regulatory Research Associates, “Major energy rate case decision in the US: January – June 2024,” July 29, 2024 (CONFIDENTIAL)

¹⁴¹ Revised Exhibit A-14, Schedule D5.18.

III. Riskiness of DTE Electric

Q48. What criticisms do Staff or Intervenors make regarding your conclusion of ROE for DTE Electric?

A48. Mr. Walters and Mr. Bandyk disagree with my finding that DTE Electric is of higher risk than the sample companies. Mr. Coppola finds that there is no ratings downgrade risk associated with a lower ROE, while Ms. Perry and Mr. Bandyk focus on regulatory mechanisms in Michigan as well as the load and generation composition.

Q49. How do you respond?

A49. Mr. Coppola opines that “[i]t is unlikely that a downgrade would occur simply due to a slightly lower ROE rate.”¹⁴² While that may be true, the credit rating is a reflection of creditworthiness or default risk and not a measure of whether the Company is receiving a “fair return.”

Mr. Walters also looks to credit agencies views, which as noted above pertain to the impact on credit worthiness, not on the risk to shareholders. In this regard, I note that Mr. Walters fails to consider the fact that DTE Electric has substantially more coal generation than the sample - - according to Value Line approximately twice that of the average sample company. The magnitude of DTE Electric’s reliance on coal means it has to invest in non-emitting resources to transition to a lower carbon environment. This inherently means a higher capital spend, which is associated with higher operating leverage and during the construction period the potential for risks associated with the build.

Ms. Perry refers to the reduced risk associated with Michigan’s regulatory framework “including the (i) use of a projected test year ..., (ii) inclusion of CWIP in rate base, (iii) and the IRM currently approved for 2024 and 2025 ...”¹⁴³ While this is true, it is also true that such mechanisms and other

¹⁴² Coppola Testimony, p. 96.

¹⁴³ Perry Testimony, p. 9.

1 regulatory mechanisms are common in the electric utility industry, as
2 demonstrated in Exhibit A-14, D5.19, which shows that a large number of
3 electric utilities have a forward test year and many have some sort of delivery
4 infrastructure recovery mechanism as well as recovery of CWIP.¹⁴⁴ Thus, these
5 do not seem to be distinguishing factors.

6 Mr. Bandyk also notes the regulatory mechanisms in Michigan (forward test
7 year, CWIP in rate base) and comments that “‘many’ but not all of the proxy
8 group companies” have those regulatory mechanisms.¹⁴⁵ While that is true, it is
9 also true that DTE Electric does not have all the mechanisms that other sample
10 companies have – the most meaningful of which is the decoupling mechanism.
11 As for the fact that DTE Electric has a slightly lower industrial load, I note that
12 the Michigan load is relatively concentrated in the automotive sector and thus
13 susceptible to changes in one industry. I also note that Michigan saw a larger
14 increase in unemployment during COVID-19 than did the U.S. on average.
15 These facts indicate that the industrial load is relatively concentrated and could
16 be volatile.¹⁴⁶ I therefore do not believe that a 2 percent lower than average
17 industrial load¹⁴⁷ materially impacts DTE Electric’s business risk relative to the
18 comparable companies. Lastly, I agree that classic cost of equity estimation
19 models measure the systematic risk and not business risk, business risk can be
20 used to place a company within a reasonable range. In addition, it is clear that
21 factors such as operating leverage,¹⁴⁸ impact the volatility of returns and hence
22 the estimated cost of equity.

23 In summary, there is nothing in discussion of business risk from Intervenor
24 that affect my recommendation.

¹⁴⁴ I do not have data on the availability of CWIP in rate base.

¹⁴⁵ Bandyk Testimony, p. 13.

¹⁴⁶ IBISWorld, “Michigan – State Economic Profile: Statistics, economic information and rankings for the Great Lakes State. [Michigan Economic Trends, Stats & Rankings | IBISWorld](#)

¹⁴⁷ Bandyk Testimony, p. 13.

¹⁴⁸ See, for example, Brealey, Myers and Allen (2017), “Principles of Corporate Finance,” 12th edition, pp. 257-258.

1 **Q50. Does the fact that there are issues in Staff's and Intervenors' testimonies**
2 **you have not addressed mean that you agree?**

3 A50. No.

4 **Q51. Does this conclude your rebuttal testimony?**

5 A51. Yes.

APPENDIX: ECAPM

Q52. What critiques do MPSC Staff and the Intervenors make regarding your use of the ECAPM methodology?

A52. Mr. Walters argues that use of adjusted betas in the ECAPM methodology is not appropriate, and the use of adjusted betas “double counts” increase impact of the adjustment.¹⁴⁹ Messrs. Ufolla, Coppola Bandyk are also opposed to the ECAPM with Mr. Bandyk arguing it is not common in regulatory proceedings.¹⁵⁰ However, neither witness spend substantial time discussing the method, so my responses shall be brief.

Q53. Do you agree with Mr. Walters that the simultaneous use of the ECAPM and adjusted betas biases the ROE estimates?

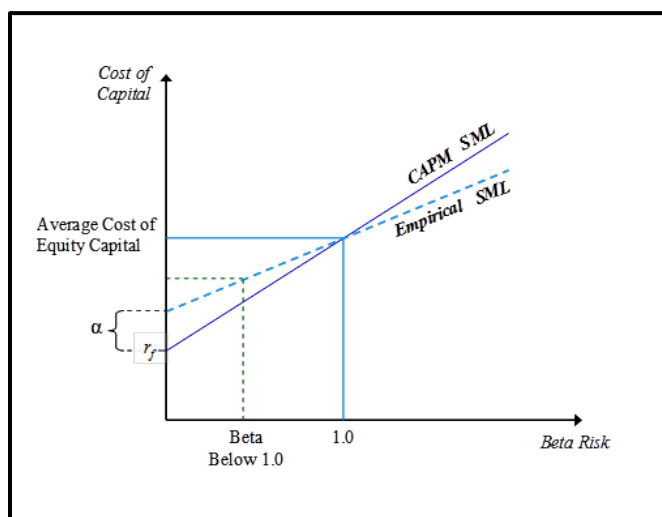
A53. Mr. Walters is concerned that I use ECAPM in combination with Value Line betas, which are Blume adjusted.¹⁵¹ He believes the adjustment is inappropriate. However, the Blume adjustment and the ECAPM are two fundamentally different and complementary adjustments, and both are well supported by the academic literature. The reason for these necessary adjustments can be shown by reference to Figure 4 below, which illustrates the empirical security market line (“SML”). The adjustment to beta corrects the estimate of the relative risk of the company, which is measured along the horizontal axis of the SML. The ECAPM adjusts the risk-return tradeoff (i.e., the slope) in the SML, which is on the vertical axis. In other words, the expected return (measured on the vertical axis) for a given level of risk (measured on the horizontal axis) is different from the predictions of the theoretical CAPM. Getting the relative risk of the investment correct does not adjust for the slope of the SML, nor does adjusting the slope correct for errors in the estimation of relative risk.

¹⁴⁹ Walters Testimony, p. 62.

¹⁵⁰ Ufolla Testimony, p. 17, Coppola Testimony, p. 89, Bandyk Testimony, p. 17.

¹⁵¹ Walters Testimony, pp. 70-71.

FIGURE 4: THE EMPIRICAL SECURITIES MARKET LINE



Importantly, the Blume adjustment has the effect of moving the beta along the x-axis whereas the ECAPM is using the y-axis. The Value Line relied upon method to make betas more precise was developed by Professor Blume.¹⁵² As shown in Professor Blume's paper, it is possible to apply a consistent adjustment procedure to historical betas that increased the accuracy in forecasting realized betas. Essentially, Professor Blume's adjustment transforms a historical beta into a better estimate of expected future beta. It is this expected "true" beta that drives investors' expected returns according to the CAPM.

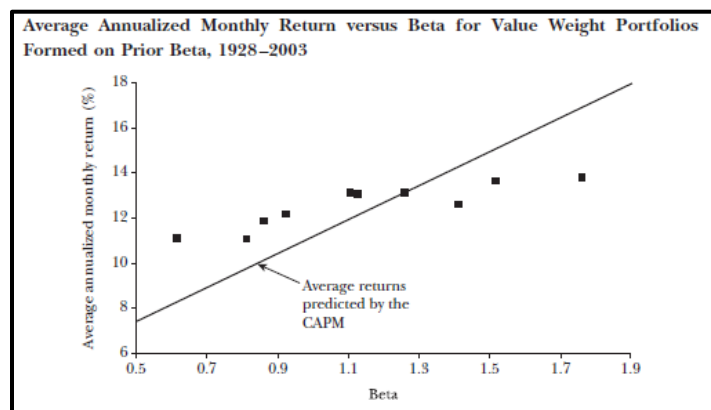
The backward-looking empirical tests of the CAPM that gave rise to the ECAPM did not suffer from bias in the measurement of betas as do a forward-looking use. Researchers plotted realized stock portfolio returns against betas measured over *the same time period* to produce plots such as Figure 5. below, which comes from the 2004 paper by Professors Eugene Fama and Kenneth French.¹⁵³ The fact that betas and returns were measured contemporaneously means that the betas used in the tests were already the best possible measure of the "true" systematic risk over the relevant time period. In other words, no adjustments were needed for these

¹⁵² Blume, Marshall E. (1971), "On the Assessment of Risk," The Journal of Finance, 26, p. 1-10.

¹⁵³ Fama, Eugene F. & French, Kenneth R. (2004), "The Capital Asset Pricing Model: Theory and Evidence," Journal of Economic Perspectives, 18(3), p. 25-46.

betas. Despite this, researchers observed that the risk-return trade-off predicted by the CAPM was too steep to accurately explain the realized returns. As explained above the ECAPM explicitly corrects for this empirical observation.

FIGURE 5: EVIDENCE FROM EMPIRICAL TESTS OF THE CAPM¹⁵⁴



Q54. Did the empirical tests that gave rise to the ECAPM use raw betas in their analyses?

A54. Yes, however, this is simply because the researchers were able to measure raw betas and realized returns from the same historical period. In other words, no adjustment to the raw beta was necessary to evaluate the market return realized for the same historical period – that is different from using betas to determine the cost of equity for future periods. Hence, the raw betas they measured accurately captured the systematic risk that impacted the returns they measured. In a sense, the measured betas and realized returns were already contemporaneous in the tests of the CAPM.

This is explicit in the article by Litzenberger et al.,¹⁵⁵ who explain (on page 376) that the estimate of “alpha” they obtain when using historical (i.e., “raw”) betas is a linear combination of the alpha that would be obtained with a perfect estimate of “true” beta and the weighting factor employed in the Blume “global

¹⁵⁴ Id., p. 33.

¹⁵⁵ Robert Litzenberger, Krishna Ramaswamy and Howard Sosin, “On the CAPM Approach to the Estimation of a Public Utility’s Cost of Equity Capital,” *Journal of Finance*, vol 35, 1979.

adjustment” procedure, which they describe with the equation $\beta_i = \omega\beta_{i(historical)} + (1 - \omega)1$. Using the equations that the authors present along with their results presented in the “Raw Betas” panel of Table 1 (on page 380 of the paper), it is possible to derive the estimate of alpha implied for use of Blume adjusted beta with $\omega=0.67$:

$$a = a' - b' \left(\frac{1 - \omega}{\omega} \right) = 0.326 - 0.330 \left(\frac{0.33}{0.67} \right) = 0.163$$

In other words, the results of Litzenberger et. al.’s study is consistent with an ECAPM alpha factor of approximately 2.0 percent when applying Blume-adjusted betas.¹⁵⁶ In that light my use of an alpha factor of 1.5 percent is conservative.

Q55. How about the argument that the ECAPM is not widely used in regulatory proceedings?

A55. First, I believe the Commission should be presented with the best possible analysis regardless of whether the analysis is “widely used” by regulators. Second, there certainly are regulatory commissions that have adopted the ECAPM methodology. Examples include the Mississippi Public Service Commission¹⁵⁷ and the New York State Public Service Commission.¹⁵⁸ Importantly, all of these regulators rely on the ECAPM in conjunction with adjusted betas and the California Public Utilities Commission did not distinguish between CAPM and ECAPM when reporting results.¹⁵⁹ This list is not exhaustive as many commissions review the evidence before them, based on which they decide on an allowed return without explicitly accepting or rejecting any specific methodology.

¹⁵⁶ Since Litzenberger, et. al. used monthly return data, their monthly alpha estimate of 0.163% corresponds to $(1.00163)^{12} - 1 = 1.97\%$ when annualized.

¹⁵⁷ Mississippi Power, PEP-5A, p. 24.

¹⁵⁸ NY PSC Case 24-E-0060, Staff Finance Panel Testimony, May 2024, p. 83-84.

¹⁵⁹ California Public Utilities Commission, “Decision 19-12-056,” December 19, 2019.

1 **Q56. What do you conclude regarding the ECAPM?**

2 A56. For the reasons discussed above, the ECAPM has merit and there is no double-
3 counting in using adjusted betas in the ECAPM. Not only is the ECAPM of
4 merit, but failing to consider the results will downward bias the results by a
5 minimal amount.

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-21534

REBUTTAL TESTIMONY

OF

AARON WILLIS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF AARON WILLIS

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Aaron Willis (he/him/his). My business address is One Energy Plaza,
4 Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services,
5 LLC, a subsidiary of DTE Energy Company as Manager, Regulatory Economics.

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my testimony is to respond to Staff and intervenor direct testimony,
14 specifically addressing the topics listed below. The absence of rebuttal on any given
15 matter does not constitute agreement by the Company.

16 1. Respond to Staff Witness Braunschweig regarding the Staff's projection of
17 the Residential Senior Credit

18 2. Respond to Michigan Environmental Council, Natural Resources Defense
19 Council, Sierra Club, and Citizens Utility Board of Michigan (MNSC)
20 Witnesses Jester and Gard's proposal for 1) separate single family and
21 multifamily residential cost of service classes and rate design and 2)
22 separate electric space heating cost of service class and rate design

23 3. Respond to MNSC Witness Jester's proposal for "Resource Adequacy" rate
24 design

Line
No.

- 1 4. Respond to Detroit Area Advocacy Organizations (Souardarity and We
- 2 Want Green, Too (DAAO) Witness Koepfel's recommendation to 1) reject
- 3 the Company's request to retire Rate Schedule D1.6 and provide optionality
- 4 for customers receiving low income assistance credits, and 2) require
- 5 additional studies of time of use rates.
- 6 5. Respond to The Michigan Energy Innovation Business Council, Institute
- 7 For Energy Innovation And Advanced Energy United (MEIU) Witness
- 8 Barnes' recommendations regarding commercial and industrial time of use
- 9 including time periods, enrollment caps, and his proposal for an additional
- 10 D4-based TOU rate.
- 11 6. Respond to Great Lakes Renewable Energy Association (GLREA) Witness
- 12 Rafson regarding proposals to "specifically allow nanogrids and
- 13 microgrids"
- 14 7. Respond to GLREA Witness Richter's proposal to allocate all capacity
- 15 costs to the "peak periods" in the Company's proposed D3.11 and D14
- 16 8. Respond to MEIU Witness Sherman and Electrify America Witness Shah
- 17 regarding proposed extensions to the D3 fast charger carve out

18

19 **Q4. Are you sponsoring any rebuttal exhibits?**

20 A4. No.

21

22 **Respond to Staff Witness Braunschweig regarding the Staff's projection of the**
23 **Residential Senior Credit (RSC) Customer Count**

24 **Q5. What does Staff Witness Braunschweig recommend regarding the projection**
25 **of Residential Senior Credit customer count?**

Line
No.

1 A5. Staff Witness Braunschweig proposes to use a three year trailing average (2020 –
2 2022) to determine the RSC customer count projection of 94,525 customers. This
3 is in contrast to the Company’s proposal of 104,224 customers, which reflects a
4 trendline from the historical years referenced by Staff and included 2023 to date at
5 the time the number was finalized.

6

7 **Q6. How does utilizing full year 2023 actual counts and 2024 actual counts to-date**
8 **support the Company’s position?**

9 A6. 2023 actual credits averaged 109,754 monthly disbursements. 2024 credits to-date
10 are averaging 125,141 monthly disbursements. In addition, Staff Exhibit S-17, pp
11 5-6 includes a Company audit response which describes an error in the Company’s
12 initial filed forecast, which undercounted the forecast by 19,849. Considering these
13 figures alongside the historical information described in the Company’s Part III
14 filing and included in Staff’s testimony, the Company’s initially proposed 104,224
15 is reasonable, and in fact likely an under-forecast. And unlike the Company’s Low
16 Income Assistance Credit, the senior credit is not tracked or reconciled, and a
17 substantial under-forecast is simply unrecoverable in the future.

18

19 **Q7. What do you recommend of the Commission?**

20 A7. I recommend the Commission update the Company’s initial senior credit customer
21 forecast of 104,224 to include the 19,849 credit counts inadvertently excluded from
22 the Company’s initial filing, for a total of 124,073.

23

Line
No.

1 **Respond to MNSC Witnesses Jester and Gard’s proposal to study separate single**
2 **family and multifamily residential cost of service classes and rate design and**
3 **separate electric space heating cost of service and rate design**

4
5 **Q8. What do Witnesses Jester and Gard propose regarding residential cost of**
6 **service and rate design?**

7 A8. Witnesses Jester and Gard broadly describe an analysis they conducted which they
8 indicate demonstrates that it is appropriate to separate the existing residential cost
9 of service class into separate classes for single family homes and multifamily
10 homes. Based on this analysis and additional commentary from Witness Jester,
11 Witness Gard recommends the Commission require the Company to “conduct a
12 similar analysis of its residential customers to determine whether continuing to
13 combine single-family and multi-family customers within a single class is justified¹”.

14
15 Witness Jester further recommends that in addition to requiring the Company to
16 study separate single family and multifamily cost of service, the Company should
17 also be required to perform a similar study based on customers with electric space
18 heating.

19
20 **Q9. What support does Witness Gard offer for his analysis and conclusions that**
21 **single family and multi family homes should have separate cost of service and**
22 **rate design?**

23 A9. Witness Gard utilized “realistic building load profiles²” from the National
24 Renewable Energy Laboratory (NREL) representing “the five Southeastern

¹ MNSC Witness Gard Pg. 5, Ln 9

² Using NREL “ResStock” data

Line
No.

1 Michigan counties of Lapeer, Macomb, Oakland, St. Clair, and Wayne”. Witness
2 Gard then “deconstruct[ed] the 5-county total residential electricity load profile into
3 separate load profiles for single-family and multi-family residential
4 subcategories³”. From this, Witness Gard determined that it is “readily apparent for
5 both critical peak (CP) and noncoincident peak (NCP) COS parameters⁴” that
6 single family and multi family are “unique”.

7

8 **Q10. Does the Company have systematic information for current and future**
9 **customers regarding their heating source or whether the residence is single or**
10 **multi family?**

11 A10. No. As a standard business practice, the Company does not know which residential
12 customers are single v. multifamily (either including or excluding duplexes and
13 mobile homes, as Witness Jester suggests should be classified as single family
14 “since these appear to have similar load profiles⁵”). In addition, unless customers
15 are utilizing a specific rate product or program which requires them to specific
16 appliances they are using (e.g. electric space heating on D2), the Company has no
17 way of knowing which appliances any given customer uses. Said differently, the
18 actual information required to conduct such a study does not exist. Exhibit CUB-
19 24 (Pg 1) acknowledges this, noting “While the Company reports total electricity
20 load profiles for each customer class, these lack sufficient granularity for this
21 analysis. By comparison, the NREL load profiles reflect specific end uses and fuel
22 types, not just total electricity load.” I agree with this assessment, because available

³ MNSC Witness Gard Pg 4, Lns 4-10

⁴ MNSC Witness Gard Pg 5, Lns 1-5

⁵ MNSC Witness Jester Pg 24, Lns 6

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No.

1 data of actual DTE Electric customer usage lacks the associated information to
2 perform this analysis, and as such the recommendation should be rejected.

3

4 **Q11. Even if the Company had the available data, is the distinction between single**
5 **family / multifamily and heating source a uniquely important driver of load**
6 **characteristics?**

7 A11. No. To illustrate this, I looked at annual usage as an independent variable to
8 determine if different usage levels indicate different relative 4CP and 12CP
9 behavior (i.e., load behavior and a proxy comparison for Witness Gard's radar
10 plots). Table 1 below shows monthly average annual (using various buckets of
11 usage provided as part of Part III supplemental residential usage distributions) and
12 the associated ratio of 1) average 4CP load to average 12 CP load and 2) average
13 1CP load to average 12CP load. I share this not to make the case that usage should
14 be the basis for different cost of service classes, but rather to underscore that there
15 is no specific significance to single v. multifamily or electric space heating as it
16 concerns which usage drivers ought to be considered for their own cost of service
17 class. As is evident from the table, the peak behavior characteristics are not
18 homogenous across different usage levels (as usage goes up, the apparent load
19 factor improves), but that does not mean it is appropriate to use usage as the basis
20 for different residential cost of service classes or rate schedules. And for
21 completeness, it is not possible for the Company to recreate the table below for
22 space heating and multifamily because these are not categories which are tracked
23 by the Company.

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1

Table 1. Peak load characteristics by residential usage levels

Annual Usage Bucket (kWh)	Customer Count	Avg Mo Usage (kWh)	Avg 4CP / Avg 12CP	Avg 1CP / Avg 12CP
23,501 - 24,000	1,388	1,993	133%	142%
17,501 - 18,000	5,785	1,483	137%	147%
11,501 - 12,000	30,532	983	144%	155%
8,501 - 9,000	66,379	733	147%	159%
5,501 - 6,000	110,135	483	149%	162%
4,501 - 5,000	113,130	400	149%	162%
3,501 - 4,000	106,027	317	147%	160%

2

3 **Q12. Do you have any other concerns with the analytic approach used for the**
4 **analysis?**

5 A12. Yes. I have two specific concerns with the analytic methodology used by Witness
6 Gard

- 7 • *The study data was used for purposes other than intended.* The analysis did
8 not seek nor use actual DTE usage data beyond the aggregate residential
9 loads from Supplemental Part III; the breakdown of load curves by housing
10 type is entirely based on the NREL ResStock Tool. As described by NREL,
11 this tool “help[s] states, municipalities, utilities, and manufacturers identify
12 which home improvements save the most energy and money⁶” and was
13 developing using “a statistical model of housing stock characteristics”. The
14 outputs for Michigan on the associated website⁷ are entirely focused on
15 building energy efficiency investments and make no suggestion that this
16 data is precise, specific, or accurate enough to serve as the basis for

⁶ [ResStock Analysis Tool | Buildings | NREL](#)

⁷ [Michigan Residential Energy Efficiency Potential \(nrel.gov\)](#)

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No.

1 assertions regarding cost of service and actual customer load shapes. In
2 addition, Exhibit CUB-24 notes “This an appropriate application of the
3 NREL load profiles. Published guidance from NREL explicitly mentions
4 Electrification Planning as one of seven use cases for its end-use load
5 profiles.” Neither this Exhibit nor NREL mention Witness Gard’s use of
6 this data as an intended or appropriate person .

- 7 • *The analysis ignores other factors that could impact load shapes.* Witness
8 Gard’s analysis and recommendation does not allow for the possibility that
9 characteristics other than single v. multi family or space heating could drive
10 different load curves. The analysis does not question the role of square
11 footage, total usage, compass orientation, tree cover/shading, or presence or
12 lack of central A/C on peak behavior. To the extent the analysis considers
13 space heating load, it appears to be one piece of a broader “building
14 electrification” scenario which is fundamentally an analysis of distribution
15 equipment loading and not metered customer loads. Notably, the analysis
16 also ignores the impacts of electric vehicles and behind the meter
17 generation. Witness Jester indicates that existing tariffs and a desire to “not
18 proliferate additional rate schedules” as reasons not to consider distributed
19 generation⁸. The Company agrees with the overall concept of rate-schedule
20 nonproliferation and suggests it be applied as a general practice.

21
22 **Q13. MNSC Witnesses Jester and Gard each proposed rates specifically for electric**
23 **space heating. Does the Company offer this rate already?**

⁸ MNSC Witness Jester Pg 27, Ln 1-7

Line
No.

1 A13. Witness Gard and Witness Jester each propose new cost of service classes and rate
2 schedules for electric heating customers. In addition to the simple lack of data on
3 heating sources, it is important to highlight that the Company currently serves a
4 portion of customers on Rate Schedule D2, which is an entirely voluntary⁹ base
5 service for customers with electric space heating. This rate is served on its own cost
6 of service class as described by Witness Maroun and myself. However, the
7 Commission chose to close new enrollments on this rate in 2015. Thus, to the extent
8 Witnesses Jester and Gard seek an optional electric space heating rate, the
9 Commission has previously closed that product, and to the extent Witnesses Gard
10 and Jester are suggesting a mandatory rate, the Company again does not know who
11 has electric heating and who does not and it would be an inappropriate approach
12 even if the Company had the data.

13

14 **Q14. What do you recommend to the Commission regarding the proposals for**
15 **separate space heating and multifamily cost of service studies?**

16 A14. I recommend the Commission reject the proposals outlined by MNSC Witnesses
17 Gard and Jester, including:

- 18 • Proposal for a single family v. multifamily cost of service study on the basis
19 that 1) the data is unavailable and 2) the proposal has not demonstrated that
20 the distinction between single and multifamily usage is the most significant
21 and uniquely warrants a new cost of service study
- 22 • Proposal for electric space heating v. no electric space heating cost of
23 service study on the basis that 1) the data is unavailable, and 2) the Company

⁹ An important distinction as the Company can only conduct the COSS and offer D2 because the electric heating customers have self-identified over time

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1 continues to offer such a rate on a grandfathered basis, with the rate having
2 been previously closed by the Commission.

3

4 **Respond to MNSC Witnesses Jester's proposal to introduce alternative capacity**
5 **charges related to his proposed changes to how production plant is allocated**

6 **Q15. Please describe Witness Jester's proposal.**

7 A15. Witness Jester proposes two alternative approaches for how production plant costs
8 are allocated, based on his interpretation of when and how capacity resources are
9 utilized. These proposals are addressed in the rebuttal testimony of Company
10 Witness Maroun, however I will address Witness Jester's further proposal to
11 modify rate design based on the aforementioned proposals. Witness Jester says
12 "Consistent with the principle that rate design should reflect cost causation as
13 allocated in the cost-of-service model, the method by which seasonal Resource
14 Adequacy is incorporated into rate design should depend on the Production Plant
15 method applied to determine cost of service.¹⁰" He additionally recommends "an
16 analysis of the seasonality for cost causation of distribution costs and distribution
17 rate designs consistent with that seasonality" – this proposal is addressed by
18 Company Witnesses Maroun and Deol in their respective rebuttal testimonies.

19

20 **Q16. What issues do you observe with this proposal?**

21 A16. I see several issues with this proposal.

- 22 • Rate design and COS are not the same. If they were the Company would:
- 23 ○ 1) collect 75% of production plant costs (75-0-25) as a demand charge
- 24 ○ 2) apply the demand charge only in the 4CP summer months.

¹⁰ MNSC Witness Jester Pg 20, Ln 3

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1 The Company does not create rates in this manner. A recommendation that rates
2 should be designed based on this or either of Witness Jester's cost of service
3 proposals would break significantly with ratemaking precedent in Michigan and
4 would be a significant change to customers who would now be presented with
5 seasonal demand rates.

6 • My interpretation of Witness Jester's proposal is that he is recommending
7 structural changes to every rate schedule the Company offers and which
8 includes capacity charges based on his recommendations to change cost of
9 service production plant allocations¹¹. For demand schedules, it appears the
10 proposal is to change to a seasonal demand charge model, which would be a
11 change for all relevant rates. For time of use rate schedules, it appears to suggest
12 modifying the time periods, the seasons, and the underlying cost allocations to
13 the rates. Said differently, the proposal would appear to require changes to more
14 than a dozen rate schedules impacting more than two million customers. The
15 Company does not support such a significant change and this recommendation
16 should be rejected.

17

18 **Respond to DAAO Witness Koeppel's recommendation to 1) reject the Company's**
19 **request to retire Rate Schedule D1.6 and provide optionality for customers receiving**
20 **low income assistance credits, and 2) require additional studies of time of use rates.**

21

22 **Q17. Please describe DAAO Witness Koeppel's discussion and recommendations**
23 **related to the Company's proposals to transition D1.6 customers and make the**
24 **low income assistance (LIA) available on all base rates?**

¹¹ Which are addressed separately by Company Witness Maroun

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1 A17. As Witness Koeppel describes, in Case No. U-21297 the Company proposed to 1)
2 transition D1.6 customers to D1.11 (or any other base rate of their choosing), 2)
3 make the LIA credit available on any residential base rate, and 3) close D1.6 as the
4 Company and State has transitioned to TOU residential rate design. The
5 Commission then ordered the Company to conduct an impact study of such a
6 transition¹². Broadly, Witness Koeppel's essential observation is that "DTE cannot
7 establish that the switch would not significantly harm its LMI customers...¹³" and
8 as such "...the Commission still does not have the necessary data to approve the
9 retirement of the D1.6 rate¹⁴".

10

11 **Q18. How does Witness Koeppel characterize the analysis conducted by the**
12 **Company?**

13 A18. Witness Koeppel suggests that the study is based on a comparison of customers
14 who have actually switched from D1.6 to D1.11 (see, for example, "DTE's analysis
15 does not provide any information on the rate of shut-offs for customers that
16 switched from the D1.6 rate to the D1.11 rate¹⁵"). For clarification, the Company's
17 study only looks at customers on D1.6 in 2022, and with their actual usage on D1.6,
18 compares their actual D1.6 bill to a hypothetical D1.11 bill in the alternative. The
19 data to perform a comparison of actual behavior on each rate using statistically
20 valid matched pairs is simply unavailable and would be extremely resource
21 intensive to design and produce.

22

¹² December 1, 2023, Order in Case No. U-21297, Pg 372

¹³ DAAO Witness Koeppel Pg 38 Ln 4

¹⁴ DAAO Witness Koeppel Pg 38 Ln 15

¹⁵ DAAO Witness Koeppel Pg 38 Ln 1

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1 **Q19. Does Witness Koeppel have any specific concerns with the analysis presented**
2 **by the Company?**

3 A19. Witness Koeppel advocates for several additional elements as part of the Bill
4 Impact Study and argues that the overall study is insufficient, but he does not appear
5 to dispute or take issue with the basic conclusions the Company's study did reach
6 based on what was included. As illustrated in my revised direct testimony at Pg 24,
7 the central, undisputed conclusion is that nearly 60% of D1.6 customers would have
8 been better off on D1.11 in 2022. Witness Koeppel acknowledges the central
9 observation of the Company's direct testimony on the topic that there is no
10 structurally adverse impact to D1.6 customers transitioning to D1.11 and in fact, on
11 average, these customers would have seen a 0.17% reduction in their bill had they
12 been on D1.11 in 2022¹⁶. No issues are highlighted regarding the underlying data,
13 the method used by the Company to compare the bills, or the basic quantitative
14 outputs. Said differently, Witness Koeppel is focused on what was not included but
15 does not contest what was included.

16

17 One additional element Witness Koeppel recommends is a "regression analysis to
18 identify any statistically significant difference in the impacts of TOU rates on
19 different customers". The analysis in the Company's direct testimony utilized
20 approximately 26,000 customers bills, both actual and calculated, to arrive at the
21 conclusion that there is no structurally adverse impact to D1.6 customers.
22 Moreover, the Company's Advanced Customer Pricing Pilot and its associated
23 analysis of different customer groups (which among the broad population of
24 residential customers includes low income customers, seniors, etc) was sufficient

¹⁶ DAAO Witness Koeppel Pg 37 Lns 14-17

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1 for the Commission to approve default TOU rates for approximately two million
2 customers (including low income, seniors, etc).
3

4 Given the approximately 26,000 customer loads used for the Company's study
5 (which was every customer on D1.6 in 2022 with more than 300 days of usage
6 data), it is not evident what more is required to establish that "the switch would not
7 significantly harm" current customers on D1.6. Moreover, Witness Koeppel
8 continues to suggest an analysis with a scope well beyond what the Commission
9 felt necessary to require before moving two million customers to TOU (many of
10 whom fit the customer categories Witness Koeppel is focused on¹⁷).
11

12 **Q20. Which rates can LIA customers choose to take service on today?**

13 A20. Today, LIA customers have no choice in their rate schedule and they are required
14 to take service on D1.6, even if they prefer D1.11, D1.2, or D1.8. The current
15 arrangement provides no optionality, which all other residential customers have,
16 and requires customers to change rates to receive the credit. Moreover, it is
17 administratively unnecessary for both the Company and customers.
18

19 **Q21. Is there precedent for the Commission to close rates utilized by specific
20 customer groups and instead offer a credit available on any rate schedule?**

21 A21. Yes. In Case No. U-17767, the Commission approved closing the Company's prior
22 Rate Schedule D1.3, which was available to senior customers as a mechanism to
23 provide a bill discount. In the alternative, the Commission approved a senior credit
24 which is now available on all residential base rates. This is fundamentally

¹⁷ E.g., family size, having a disability, having children and elders, having all working parents as described by DAAO Witness Koeppel Pg 35, Ln 14.

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1 analogous to the entirety of the Company's request in this case regarding D1.6, one
2 that is supported by a robust record in this and prior cases.

3

4 **Q22. What action do you recommend of the Commission regarding the Company's**
5 **D1.6 proposals?**

6 A22. I recommend the Commission approve three things:

- 7 • The transition of all D1.6 customers to D1.11 as proposed by the Company.
8 This will conclude the Company's overall transition of residential
9 customers to TOU rates.
- 10 • Close Rate Schedule D1.6 at such time all customers are transitioned.
- 11 • Make the LIA credit available on any residential base rate for which the
12 customer otherwise qualifies. In doing so, customers will have the
13 flexibility and freedom to take service on the rate of their choosing while
14 also removing the complication of forcing customers to change rates when
15 they begin and when they no longer receive the credit.

16

17 **Respond to MEIU Witness Barnes' recommendations regarding commercial and**
18 **industrial time of use including time periods, enrollment caps, and his proposal for**
19 **an additional D4-based TOU rate.**

20

21 **Q23. What does MEIU Witness Barnes recommend regarding the Company's**
22 **commercial and industrial time of use rate proposals?**

23 A23. Witness Barnes makes five separate recommendations. Here I address and discuss
24 the first three, while the recommendations related to implementation timing and

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1 rate comparison reports are addressed in the rebuttal testimony of Company
2 Witnesses Hatsios and Sharma. In summary, Witness Barnes recommends:

- 3 • There should be a third commercial/industrial TOU rate which is a
4 “corollary for Rate Schedule D4”.
- 5 • The rates should have a common on-peak pricing period utilizing 1:00 –
6 5:00 weekdays, which would change the proposed on-peak period for D14
- 7 • The proposed enrollment caps should be rejected.

8 I will address each of Witness Barnes’ recommendations below.

9

10 **Q24. Why does Witness Barnes believe it is appropriate to introduce a third C&I**
11 **rate associated with Rate Schedule D4?**

12 A24. Witness Barnes begins by describing the customers who, all else equal, relatively
13 benefit on D3 and D4 – higher load factor customers benefit relatively from demand
14 rates and lower load factor customers benefit relatively from volumetric rates¹⁸.
15 Witness Barnes then observes that, because D3 and D4 have “different usage
16 determinants, different revenue requirements, and different average volumetric
17 rates”, they have different average power supply volumetric costs. Because the
18 proposed secondary voltage TOU rate is revenue neutral to D3, but not the
19 relatively less expensive D4, Witness Barnes concludes that D4 customers would
20 be without sufficient choice of rate schedules unless the Company also offers a
21 TOU rate which is revenue neutral to D4. Witness Barnes’ central argument is that
22 D3 and D4 should have linked TOU rate schedules because the average power
23 supply rate on those rates is not the same.

24

¹⁸ MEIU Witness Barnes Pg 9 Ln 4

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1 **Q25. Do you agree with Witness Barnes' approach to TOU rate design?**

2 A25. No. The average effective rate on any rate schedule is driven primarily by the
3 efficiency of the usage on the rate. All else equal, a cost-of-service class with a
4 higher load factor will have a lower average rate than one with a lower load factor.
5 D3 and D4 are in different cost of service classes, and D4 has a higher average load
6 factor and thus lower average rates. D4 rate design, which utilizes demand charges,
7 reinforces this self-selection for higher load factor customers. If the Company
8 offered a TOU rate using a D4 revenue neutral design, the "lower rate" would be a
9 fleeting reality.

10

11 Two groups of customers would presumably seek to enroll on a D4-neutral TOU
12 rate in the near term. The first group would be D4 customers with a load factor high
13 enough to justify being a D4 customer but one that is lower than the D4 average.
14 This group would switch rates to maintain the benefits of the lower average power
15 supply rate while simultaneously avoiding the power supply demand charge design
16 that drives the more efficient usage (and which in turn drives the lower average
17 rate). All else equal, this would have the natural effect of *increasing* the average
18 power supply rate on Witness Barnes' proposed D4.1 to something between the
19 current D3 and D4 average power supply rates¹⁹. Such a change would require a
20 new cost of service class for D4.1 in the future so as not to adversely impact the D4
21 cost of service class. The second group would be those current D3 customers with
22 the highest load factors, but which are not high enough to benefit from D4 today.
23 In the future, they could benefit from the lower power supply cost of a D4-neutral
24 rate more than the distribution demand charges harms them (if at all). This would

¹⁹ As a corollary, the D4 average power supply rate would decrease as it sheds lower load factor customers

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1 also have the natural effect of *increasing* the average D4.1 power supply rate.
2 Described differently, average rates, regardless of the rate design, simply reflect the
3 characteristics of the customers on the rates. Over time, Rate Schedule D4.1 would
4 simply reflect the poorer load factor relative to D4 and (presumably) better load
5 factor relative to D3 or D3.11.

6

7 To the extent an existing D4 customer could benefit by switching to the Company's
8 proposed D3.11, they would be able to do so. Moreover, if the customer exceeds
9 50 kW of demand, they may also be able to leverage the Company's proposed
10 primary TOU rate D14, which has an even lower average power supply rate (by
11 13% compared to D4 and based on the better D11 load factor) and a lower
12 distribution demand charge. Far from a "poison pill" for existing D4 customers²⁰,
13 the Company's TOU proposal is conceptually sound and offers options for all C&I
14 customers.

15

16 **Q26. What was the Company's rationale for designing the proposed secondary**
17 **voltage TOU rate revenue neutral to D3 and not D4?**

18 A26. In its Order in Case No. U-21297, the Commission included a reference to "mass
19 market appropriate TOU rate options" in the introduction to the discussion.
20 Considering customer counts on D3 and D4, D3 is clearly the "mass market" analog
21 upon which to develop a time of use rate. Whereas D3 has approximately 200,000
22 customers, D4 has fewer than 10,000 customers.

23

²⁰ MEIU Witness Barnes Pg 10 Ln 7

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1 **Q27. Witness Barnes proposes that the Company’s proposed D14 utilize the same**
2 **1:00 – 5:00 on-peak period as proposed D3.11. Do you agree?**

3 A27. No. The Company designed the D14 on-peak period to maintain consistency with
4 the existing D11 on-peak period²¹. The D3.11 on-peak period is proposed to
5 broadly align with 1) summer system coincident peaks and 2) summer class peaks.
6 The inclusion of system peaks aligns pricing periods with system highest use
7 periods, and the inclusion of summer class peaks limits the possibility that the on-
8 peak period could drive snapback and inadvertently set a new class peak hour on
9 the edge of the on-peak period. Utilizing the Company’s Supplemental Part III
10 filing, Att 5 (29), 20% of the primary summer peaks from 2018-2022 are before
11 1:00 pm. An on-peak window beginning at 1:00 pm certainly presents the
12 possibility of customer’s shifting load to before the period and in doing so
13 inadvertently create a new system peak hour in the noon – 1:00 pm hour.

14

15 In addition, Witness Barnes’ indicative D14 rates under a 1:00 – 5:00 scenario
16 appear to assume no change in load behavior, which for voluntary time of use rates
17 with new pricing windows is highly unlikely. The Company’s proposed D14
18 included no shift because it mimics the existing TOU pricing window on D11 and
19 therefore is already embedded in existing rate design.

20

21 **Q28. What does Witness Barnes recommend regarding the Company’s proposed**
22 **enrollment caps on D3.11 and D14?**

23 A28. Witness Barnes is broadly opposed to enrollment caps, noting “The introduction of
24 such rates should not be accompanied by new constraints on their availability. At

²¹ Further discussed in the revised direct testimony of Company Witness Willis, Pg 41 Ln 20

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1 best, such limits introduce administrative inefficiency since their removal would
2 require further litigation in future rate cases. At worst, they may further delay the
3 availability of TOU rates to all customers that wish to participate.²²”

4
5 He further describes his view of new rate introductions and their attendant cost-
6 recovery risk, saying “any supposed risk of under-recovery rests on speculation
7 rather than evidence, and such risk is not necessarily greater or lower than the risk
8 of under-recovery present within the broader groups of customers²³”. Continuing
9 on this topic, Witness Barnes says “the prospect of lower revenue is not by itself
10 indicative of under-recovery of costs or unreasonable cost-shifting to other
11 ratepayers²⁴”

12
13 Lastly, Witness Barnes indicates concern that caps proposed by the Company are
14 not time-bound but are instead dynamic to enrollments and actual customer usage
15 information.

16
17 In summary, Witness Barnes believes 1) caps are generally unreasonable will
18 prevent customer enrollment on the rates, and 2) that to the extent usage behavior
19 is different than the Company’s forecast, any resultant under-recovery is
20 appropriate.

21

22 **Q29. How do you respond to the proposed elimination of the enrollment caps?**

23 A29. They should be retained. Specifically:

²² MEIU Witness Barnes Pg 16, Ln 10

²³ MEIU Witness Barnes Pg 16 Ln 18

²⁴ MEIU Witness Barnes Pg 17, Ln 4

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- 1 • *The evidence does not support the claim that caps will prevent enrollment.* In
2 his continuing discussion of enrollment caps, Witness Barnes introduces for
3 reference the experience of Consumers Energy’s (CE) implementation and
4 initial enrollment caps. As described, CE initially sought approval of their
5 commercial secondary and primary rates in 2017, seven years ago. In that time,
6 according to Witness Barnes, CE has seen enrollments representing ~0.84% of
7 commercial secondary customers²⁵. The Company’s proposed cap for initial
8 D3.11 enrollment is equivalent to 0.5% of commercial secondary customers²⁶.
9 Given the seven years it apparently took for 0.84% of CE’s commercial
10 secondary customers to enroll on their TOU rate, it does not seem likely that
11 there will be any near-term concerns related to enrollment limitations on D3.11.
12
13 Regarding D14, Witness Barnes again notes the CE experience, which provides
14 a nearly analogous situation for the Commission to consider. He highlights that
15 CE initially proposed, and the Commission approved, enrollment caps on their
16 then new primary TOU rate. The reason provided by CE, and which Witness
17 Barnes highlights, is “At the time of this expansion, ***Schedule GPTU had not***
18 ***been in place long enough for it to be evaluated as a separate rate schedule***
19 ***in Consumers Energy’s cost of service study*** so rates continued to be based on
20 a revenue-neutral mapping to the broader primary voltage rate schedule²⁷,
21 *(emphasis added)*. This is nearly verbatim to my direct testimony on the topic,
22 which says, “Until such time that D14 is supported by its own cost of service
23 class... the Company proposes to limit total load on this rate to 50 MW of

²⁵ MEIU Witness Barnes Pg 19 Ln 9

²⁶ Willis Revised Direct, Pg 32 Ln 4

²⁷ MEIU Witness Barnes Pg 18, Ln 7

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1 contract capacity²⁸”. Also of relevance, today CE does utilize a separate COS
2 class for GPTU, presumably because it has the historical data to do so.

3

4 • *Short term caps prevent adverse outcomes.* The Company’s rates are based on
5 the best available forecast of 1) what customer usage, by rate schedule, will be
6 in the projected test year, and 2) the Company’s revenue requirement in the
7 projected test year. The Company’s best available forecast of customer usage
8 on the proposed D3.11 and D14 includes more uncertainty than a long-existing
9 rate because they each introduce fundamentally different pricing signals to
10 customers. The Company’s existing rates have strong historical, empirical data
11 to support forecasts – new rates with fundamentally different pricing structures
12 do not. One outcome of this, particularly for larger and more sophisticated
13 primary customers, could be drastically different load profiles than what was
14 anticipated based on historical information (and ultimately incorrect cost
15 allocation assumptions).

16

17 Additionally, the Company is concerned with Witness Barnes’ assertion that
18 “the prospect of lower revenue is not by itself indicative of under-recovery of
19 costs or unreasonable cost-shifting to other ratepayers”. While the Company
20 appreciates that actual revenue is unlikely to be exactly the ordered revenue
21 requirement, it is inappropriate to introduce potential structural drivers of
22 under-recovery. While D14 is allocated costs based on the load factor and
23 efficiency of D11, it will almost certainly have a lower realized load factor due
24 to the fact that the rate is more attractive to lower load factor customers. In the

²⁸ Willis revised direct Pg 43 Ln 14

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1 short run, their effective rates would be artificially low. It is therefore
2 appropriate to implement a cap until such time the rate is supported by its own
3 cost of service class.
4

5 **Q30. In summary, what do you recommend the Commission order regarding the**
6 **Company's C&I TOU proposals and MEIU's recommendations?**

7 A30. I recommend the Commission approve the rates as filed, including time periods and
8 caps, and recommend the Commission decline to adopt MEIU's proposal for a third
9 TOU rate based on D4.
10

11 **Response to GLREA Witness Rafson regarding proposals to "specifically allow**
12 **nanogrids and microgrids"**
13

14 **Q31. What is GLREA's recommendation regarding microgrids and "nanogrids"?**

15 A31. Witness Rafson describes several apparent benefits of microgrids and nanogrids
16 and then recommends the Commission "should specifically allow nanogrids and
17 microgrids" and "This regulatory step is particularly justified as a response to
18 DTE's failure to serve essential power to their customers²⁹".
19

20 **Q32. As described by Witness Rafson, do the Company's tariffs allow "nanogrids"**
21 **today?**

22 A32. Yes. Witness Rafson describes the benefits of nanogrids as "..(behind the meter)
23 installations of any combination of backup generators, solar and energy storage
24 facilities, EV charging (including bi-directional EV charging) technology, and

²⁹ GLREA Witness Rafson Pg 13 Ln 11 and 20

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1 other demand response controls allow customers to provide for themselves reliable,
2 potentially renewable, energy and can help to ensure that they have the essential
3 power they need³⁰. All of the technologies described by Witness Rafson are
4 available to customers under current Company tariffs and require no changes to the
5 Company's tariffs.

6

7 **Q33. Are there regulatory and legal concerns with Witness Rafson's "microgrid"**
8 **proposal?**

9 A33. Yes. The relevant testimony suggests that microgrids include service between
10 multiple individual customers, islanded groups of individual customers, and
11 "submeters" across neighborhoods³¹. The previous description suggests that it
12 would be appropriate and legal for groups of individual customers to create single
13 service points, behind which they act as their own electric utility service. While this
14 may be appropriate for single customer campuses or large commercial sites with
15 single service points, what Witness Rafson describes would require fundamental
16 change to utility regulation in Michigan and the concept of who is a utility. This
17 should be rejected.

18

19 **Respond to GLREA Witness Richter's proposal to allocate all capacity costs to the**
20 **"peak periods" in the Company's proposed D3.11 and D14**

21 **Q34. Please describe Witness Richter's capacity cost recovery proposal?**

22 A34. Witness Richter says "The charge for capacity reflects the cost of ensuring there is
23 sufficient generation and transmission available to meet that peak load. Therefore,
24 it would be accurate to assign the entire cost of capacity to the peak demand time

³⁰ GLREA Witness Rafson Pg 13 Ln 15

³¹ GLREA Witness Rafson Pg 13 Ln 6

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1 period³².” He then goes on describe why these rates are appropriately modified as
2 he recommends, saying “the proposed C3.11 and D14 commercial TOU rates are
3 purely optional, at the discretion of the customer³³”, comparing this optional design
4 to similar capacity cost proposal which the Commission rejected.

5 Ultimately, he recommends:

- 6 • Redesign D3.11 and D14 to include his proposed ‘on-peak only’ capacity
7 recovery approach to be filed 60 days following the conclusion of the instant
8 case, a recommendation which is buttressed with extracts from James
9 Bonbright which say “The generation, transmission, and distribution systems
10 have been built to serve peak demand. During off-peak periods much of this
11 capacity is idle...” and “[e]conomic efficiency simply dictates that consumers
12 should be faced with prices reflecting the true costs they impose on society
13 regardless of how they choose to react to these tariffs³⁴”.
- 14 • The Commission order the Company to include in its next case “a discussion of
15 the pros and cons of making a TOU rate structure the default, standard rate
16 structure for all secondary voltage commercial customers, and to collect metrics
17 of success on the pilots to prepare for making them the default standard rate³⁵”

18

19 **Q35. What observations do you have with respect to Witness Richter’s**
20 **recommendations?**

21 A35. Witness Richter’s central arguments are 1) economic efficiency is the only
22 important consideration in rate design, and 2) this proposal is supportable because
23 it is a voluntary and not mandatory rate.

³² GLREA Witness Richter Pg 13 Ln 3

³³ GLREA Witness Richter Pg 14 Pn 11

³⁴GLREA Witness Richter Pg 13 Ln 17 and 22

³⁵ GLREA Witness Richter Pg 16 Ln 12

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- 1 • *Economic efficiency.* As a conceptual point, the Company does not agree
2 that its capacity only exists to serve the 4CP (or the on-peak periods more
3 generally). The Company has load at all hours of the day and must have
4 capacity to serve that load. In addition, the natural conclusion of Witness
5 Richter’s citation of Bonbright focused on rates reflecting “true costs” and
6 idle capacity in the off-peak would be to have demand rates for all
7 customers³⁶, since capacity is reflected as a demand measure and Witness
8 Richter emphasizes the Bonbright conclusion that “only the operating costs
9 need to be considered³⁷” in the off peak. This is an unreasonable
10 recommendation.
- 11 In addition, this recommendation would suggest all capacity costs be
12 recovered in only the 4CP on-peak periods to maintain consistency with the
13 basic approach of production plant allocation. However, that would 1)
14 create extraordinarily high summer on-peak rates³⁸ and 2), as I remarked in
15 response to Witness Jester above, cost of service and rate design are not the
16 same and have different considerations. While the economic efficiency of
17 rate design is certainly one consideration (and one the Commission has
18 evidenced support of via recent developments of TOU rates), it is not the
19 only consideration.
- 20 • *Mandatory v voluntary v pilot.* That these proposals are for voluntary,
21 optional rates does not mean that the rate should be inappropriately
22 designed. Witness Richter frames D3.11 and D14 as “pilots” and on this

³⁶ Which, to be clear, the Company is not proposing.

³⁷ GLREA Witness Richter Pg 13 ln 25

³⁸ Elsewhere in testimony (Pg 36, Ln 11), Witness Richter refers to the dynamic peak pricing rate schedule D1.8 as having a “punishingly high” rate during CP-events. While the Company has not calculated the impacts of Richter’s proposal, it would invariably lead to much higher on peak or summer on-peak rates compared to the status quo, which could similarly be described as “punishing”

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1 basis concludes that “bold” and “radical³⁹” rate design is appropriate. I
2 disagree. For one, these are not pilot rates and are intended to be enduring,
3 reasonable designs for commercial and industrial TOU rates. That they are
4 voluntary (pilot or otherwise) does not lead to the conclusion that the
5 Commission should support radical rates. Second, Witness Richter
6 seemingly acknowledges this long-term view because he proposes a future
7 discussion of making these TOU rates default for the relevant customers
8 and in addition “to collect metrics of success on the pilots to prepare for
9 making them the default standard rate”. These rates cannot both be a pilot
10 suitable for non-standard rate design while also a prospective default rate.

11

12 **Q36. What do you recommend to the Commission regarding Witness Richter’s**
13 **TOU proposals?**

14 A36. The Commission should reject Witness Richter’s recommendations because:

- 15 • Capacity serves load in all hours
- 16 • Economic efficiency is but one of many considerations in rate design and
- 17 in this case would drive substantial impacts to customers
- 18 • These are, and should remain, optional (non-pilot) rates. It would be
- 19 exceptionally premature to begin any discussion of *requiring* these rates
- 20 when the Commission has yet to approve their basic structure and there are
- 21 currently no customers enrolled on them.

22

23 **Respond to MEIU Witness Sherman and Electrify America Witness Shah regarding**
24 **proposed extensions to the D3 >1000 kW fast charger exemption**

³⁹ GLREA Witness Richter Pg 14 Ln 13

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1 **Q37. Please describe the recommendations of Witnesses Sherman and Shah?**

2 A37. MEIU Witness Sherman says that in order to “provide sufficient time for DCFC
3 usage to approach a market equilibrium” and to “ensure that demand-based rates
4 do not inhibit the expansion of DCFC for sites with high demand but low utilization
5 rates in the interim”, the Commission should extend the D3 >1000kW fast charger
6 exemption for four years, until January 1, 2030⁴⁰⁴¹.

7
8 Similarly, Electrify America Witness Shah says “Given the timelines associated
9 with DCFC site development and investment justification, which are often over a
10 10-year or longer period, two years of guaranteed demand charge relief is not a long
11 enough period to provide enough cost certainty to Electrify America when it is
12 making investment decisions in DTE’s service territory. DTE should therefore
13 modify its tariff language to allow DCFC sites built before a specified date,
14 preferably by 2028 or later, to be able to take service under the D3 rate⁴²”.

15

16 **Q38. Does the Company agree with these proposals?**

17 A38. No. The Commission previously extended the exemption period in the Company’s
18 last general rate case⁴³ to the current date of June 1, 2026 (extended from June 1,
19 2024). Neither Witness Sherman nor Shah provides any particular evidence of the
20 necessity of their proposes changes. The Company’s D3 tariff, with or without the
21 1000 kW exemption, will continue to serve fast chargers less than 1000 kW

⁴⁰ The Company notes for completeness that the current D3 tariff (rate book sheet D-18.00) indicates a June 1, 2026 date, not a January 1, 2026 date.

⁴¹ MEIU Witness Sherman Pp 52-53

⁴² EA Witness Shah Pp 4-5

⁴³ Dec 1 Order in Case No. U-21297 Pg 341

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1 indefinitely and there is no evidence that the tariff is inhibiting the deployment of
2 fast chargers.

3

4 Witness Shah suggests that the current two year exemption is not sufficient because
5 investment justifications for such assets are made over “a ten year period or
6 longer⁴⁴”. All of the Company’s rates are subject to periodic change, and all of the
7 Company’s customers must make investment decisions based on the best
8 information at hand. No other customer is granted a ten year period of certainty
9 over their rate options and it would be inappropriate to do so here, particularly as
10 the outcome of the recommendation would continue to defer the requirement that
11 customers with very large (>1000 kW) demands be served on a demand-based rate.
12 Moreover, the Company has proposed a primary voltage time of use rate in this
13 case which does not include power supply demand charges, which if approved
14 provides yet another option for charging customers.

15

16 As such, I recommend the Commission reject the proposals to further modify the
17 >1000 kW fast charger exemption on D3.

18

19 **Q39. Does this conclude your rebuttal testimony?**

20 A39. Yes, it does.

21

⁴⁴ EA Witness Shah Pp 4-5

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.)

SHERRI L. WISNIEWSKI

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF SHERRI L. WISNIEWSKI

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1 **Q1. Are you the same Sherri L. Wisniewski who previously offered testimony in**
2 **this proceeding?**

3 A1. Yes, I am.

4

5 **Q2. What is the purpose of your rebuttal testimony?**

6 A2. The purpose of my testimony is to:

- 7 • Rebut the property tax expense adjustment proposed by Attorney General
8 (AG) Witness Coppola. If capital disallowances are ordered by the
9 Commission, the methodology used by Witness Coppola to adjust property
10 tax expense is inaccurate.
- 11 • Rebut the property tax expense adjustment proposed by Association of
12 Businesses Advocating Tariff Equity (ABATE) Witness York. If capital
13 disallowances are ordered by the Commission, the methodology used by
14 Witness York to adjust property tax expense is inaccurate.
- 15 • Propose a methodology for adjusting property tax expense if capital
16 disallowances are ordered by the Commission.

17

18 The purpose of my testimony is limited to discussion of the methodology used to
19 calculate a property tax adjustment if the Commission orders a capital
20 disallowance. The purpose of my testimony is not to discuss the reasonableness of
21 any capital adjustments proposed by the Staff or any intervenors, as that is being
22 addressed in the rebuttal testimony of other Company witnesses. The absence of a
23 discussion of other matters in my rebuttal testimony should not be taken as an
24 indication that I agree with other aspects of any Staff or intervenor testimony.

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1 **Q3. Are you sponsoring any rebuttal exhibits?**

2 A3. No.

3

4 **Rebuttal of the Property Tax Expense adjustment proposed by AG Witness Coppola**

5 **Q4. What property tax expense adjustment did Witness Coppola propose?**

6 A4. On page 125, lines 4 through 10 of Witness Coppola's testimony, Witness Coppola
7 is recommending a reduction in property tax expense for the projected test year of
8 \$12.3 million as calculated on Exhibit AG-18. The methodology Witness Coppola
9 is using to calculate this adjustment is to take the AG's proposed capital expenditure
10 reductions for 2024 and prior years, excluding Customer Service/IT, and multiply
11 this by 96%, 50%, and a millage rate of 56.0.

12

13 **Q5. Do you agree with the methodology Witness Coppola is using to calculate the**
14 **property tax expense adjustment on proposed capital expenditure reductions?**

15 A5. No. This methodology fails to consider the following aspects of the property tax
16 expense calculation:

- 17 • Not all capital expenditures are subject to property tax in the same way. Plant
18 additions and changes in construction work in progress (CWIP) are taxed
19 differently from each other, and removal costs are not subject to property tax
20 at all. Witness Coppola's methodology does not distinguish those components
21 of the AG's proposed capital expenditure reductions so that property taxes on
22 each component can be calculated correctly.
- 23 • The Company treated capital expenditures related to steam power generation
24 and nuclear generation as nontaxable expenditures in this filing. Witness
25 Coppola's methodology does not exclude these components of the proposed

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1 capital expenditure reductions from the calculation of the property tax
2 expense adjustment.

3 • As discussed in my direct testimony (page 12, lines 6 through 7), the
4 Company is seeking recovery of property tax expense of \$328.8 million for
5 the projected test period (January 1, 2025, through December 31, 2025).
6 Property tax expense refers to the amount of property taxes deducted for book
7 purposes, whereas property tax liability refers to the amount of property taxes
8 payable to local governments. As discussed in my direct testimony (page 12,
9 lines 17 through 22), the Company expenses its property tax liability over a
10 two-year period, with the total liability of each year being expensed 39% the
11 current year and 61% the subsequent year. Therefore, if there is a change in
12 the property tax liability in any given year, property tax expense for that same
13 year will change by only 39% of that change in the property tax liability. For
14 example, if the 2025 property tax liability is reduced by \$100,000, 2025
15 property tax expense is reduced by only \$39,000 (39% of \$100,000). Witness
16 Coppola's methodology ignores this step of expensing the property tax
17 liability over a two-year period.

18

19 By not taking these factors into consideration, Witness Coppola's methodology
20 results in a significant overstatement of the property tax expense adjustment on
21 proposed capital expenditure reductions.

22

23 **Rebuttal of the Property Tax Expense adjustment proposed by ABATE Witness York**

24 **Q6. What property tax expense adjustment did Witness York propose?**

25 A6. On page 32 of Witness York's testimony, Witness York is recommending a
26 reduction in property tax expense for the projected test year of \$6.1 million, as

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1 stated in TABLE JAY-4, line 3. Nowhere in her testimony or exhibits does Witness
2 York explain why she is adjusting property tax expense or the methodology she is
3 using to calculate the adjustment. However, Witness York's workpaper JAY WP-
4 3 , tab Table JAY-4, row 35, does include a formula showing the proposed property
5 tax adjustment of \$6.1 million is calculated by dividing ABATE's proposed capital
6 expenditure adjustments by 2 and multiplying this by 1.5%.

7
8 **Q7. Do you agree with the methodology Witness York is using to calculate the**
9 **proposed property tax expense adjustment?**

10 A7. No. While Witness York offers no explanation for her proposed property tax
11 adjustment, it appears that she is attempting to adjust property tax expense related
12 to ABATE's capital expenditure adjustments. This methodology bears no
13 resemblance to how the Company calculated property tax expense in this case,
14 which is described in my testimony beginning on page 7, line 20, and continuing
15 through page 13, line 6. If capital disallowances are ordered by the Commission,
16 the methodology that should be used to calculate the corresponding adjustment to
17 property tax expense should follow the same methodology the Company utilized to
18 calculate property tax expense in this case.

19
20 **Proposed Methodology for adjusting Property Tax Expense on Capital Disallowances**

21 **Q8. What property tax expense adjustment did Staff Witness Hecht propose?**

22 A8. Starting on page 7, line 9, and continuing through page 8, line 5 of Staff Witness
23 Hecht's testimony, Witness Hecht is recommending a reduction in property tax
24 expense for the projected test year of \$117,000. This is also shown on page 4 of
25 Witness Hecht's testimony in Figure 1. This is based on the Staff's adjustments to

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1 the Company's historic and projected capital expenditures and is calculated in WP-
2 JJH-1.
3

4 **Q9. Do you agree with the methodology Staff Witness Hecht is using to calculate**
5 **the proposed property tax expense adjustment?**

6 A9. Yes. Staff Witness Hecht's methodology is very similar to the methodology the
7 Company utilized to calculate property tax expense in this case.

8 • Capital adjustments to steam power generation, nuclear generation, and IT are
9 excluded.

10 • Capital adjustments for some of the more significant components of CWIP
11 are separately identified.

12 • Taxable capital adjustments impact the property tax liability the year after
13 they are incurred.

14 • First year STC multipliers of 96% and 50% are applied to capital adjustments
15 related to plant additions and CWIP, respectively, to calculate true cash value.

16 • True cash value is multiplied by 50% to calculate taxable value.

17 • Taxable value is multiplied by the estimated millage rate of 56.0 to calculate
18 the change in the property tax liability.

19 • Calendar year property tax expense is adjusted by 39% of the change in the
20 property tax liability in year 1 to reflect the Company's two-year expensing
21 methodology.

22

23 **Q10. If capital disallowances are ordered by the Commission, what methodology**
24 **should be used to calculate the corresponding adjustment to property tax**
25 **expense in this case?**

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1 A10. If capital disallowances are ordered by the Commission, Staff Witness Hecht's
2 methodology is reasonable and should be used to calculate the corresponding
3 adjustment to property tax expense. Staff Witness Hecht's methodology follows a
4 methodology that is very similar to the methodology the Company utilized to
5 calculate property tax expense, and any differences are immaterial in this case.

6

7 **Q11. Does this complete your rebuttal testimony?**

8 A11. 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-21534

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on August 16, 2024, she served a copy of DTE Electric Company's Rebuttal Testimony and Exhibits of Witnesses, Morgan Elliott Andahazy, Robert A. Bellini, Pina Bennett, Shawn D. Burgdorf, Jeffrey C. Davis, Satvir S. Deol, Keegan O. Farrell, Matthew A. Fix, Neal T. Foley, Margaret E. Guillaumin, Shannen M. Hartwick, Michael J. Hatsios, Brian L. Hill, Jerome K. Hooper, Allen J. Kryscynski, Timothy J. Lepczyk, Habeeb J. Maroun, Pankaj Sharma, Jason E. Sparks, Rachel C. Steudle, Theresa M. Uzenski, Bente Villadsen, Aaron Willis, and Sherri L. Wisniewski in the above captioned matter, via electronic mail and secure portal links, upon the persons listed on the attached service list and Mr. Bellini's Exhibit A-40, confidential Schedule EE5 , Mr. Deol's Exhibit A-50, CEII confidential Schedule OO2, Ms. Elliott Andahazy's Exhibit A-51 confidential Schedules PP2, PP4, PP6, PP8, and PP10, Ms. Hartwick's Exhibit A-53 CEII confidential Schedule RR2, and Mr. Kryscynski's Exhibit A-43 CEII confidential Schedule HH4 was filed under seal with the Commission.

Estella R.
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MPSC Case No. U-21534

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