

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,  
for miscellaneous accounting authority.

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Case No. **U-21860**  
(e-file paperless)

**MICHIGAN PUBLIC SERVICE COMMISSION**  
**STAFF'S INITIAL BRIEF**

**MICHIGAN PUBLIC SERVICE  
COMMISSION STAFF**

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**DATED: October 24, 2025**

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## I. INTRODUCTION AND OVERVIEW

In its initial filing, the DTE Electric Company (DTE or the Company) projects that it will experience a total electric revenue deficiency of \$574.067 million for the test year ending December 31, 2026 (A-11, Schedule A1), alternatively Staff projects that DTE's total electric revenue deficiency will be \$251.955 million. (Appendix A.) The primary reasons for Staff's lower projected revenue deficiency are Staff's lower rate base, return on equity, return on tree trim and Monroe regulatory assets, and operating expenses. This is highlighted as follows:

- i. DTE's projected total rate base is \$23.560 billion, while Staff's total projected rate base is \$23.170 billion—\$390.346 million less than the Company's. (Appendix B.) It is lower because Staff reduced the Company's plant in service by \$407.432 million (including adjustments to production, distribution, demand side management, information technology, corporate staff, and charging forward), increased the depreciation reserve (an offset to total utility plant) by \$22.910 million, and reduced working capital by \$5.824 million. (Appendix E.)
- ii. DTE's proposed ROE is 10.75%. Staff's recommended ROE is 9.80%. (Appendix D.) Each of the intervening parties recommend ROEs at or below 9.85% (Attorney General's ROE). Staff's lower ROE, compared to the Company, reduces the Company's projected revenue deficiency by about \$118.1 million. Staff's recommended ROE differs from the Company's by 95 basis points because Staff used several different ROE inputs.
- iii. DTE projects that its total company operating expenses will be \$4.671 billion, while Staff projects that it will be \$4.566 billion. Staff's projection is \$104.409 million less than the Company projects. (Appendix C.) Staff's proposed operating expenses are lower because Staff adjusted the Company's Operation and Maintenance (O&M) expense by \$104.409 million to reduce, among other things, generation, distribution, uncollectibles, regulated marketing, corporate support, and pension and benefits expense.

Staff's proposed disallowances are justified and well supported. Staff's recommendations strike the right balance between DTE's interests and its ratepayers' interests. Public utilities are entitled to a reasonable opportunity to earn a reasonable rate of return on their investments. *ABATE v Public Service Comm*, 430 Mich 33, 39 (1988.) Simultaneously, ratepayers are entitled to just and reasonable rates. The just-and-reasonable-rate doctrine is "aimed at navigating the straits between gouging utility customers and confiscating utility property." *Verizon Communications, Inc v FCC*, 535 US 467, 481 (2002.) Staff's adjustments are well within these bounds.

Staff's objective is recommending "just and reasonable rates that are fair to both ratepayers and the company." *In re Detroit Edison Co*, MPSC Case No. U-15244, 12/23/08 Opinion & Order, p 11. Although many of DTE's proposed rate increases are justified, many are not. In several instances, the Company has overreached by increasing its capital-expenditure and operating-expense projections beyond reasonable expectations. In other instances, the Company has ignored Commission precedent and asked to recover expenses that it has requested before and been repeatedly denied. Staff's adjustments correct these excesses.

In conclusion, DTE has not justified a \$574.067 million rate increase. However, considering the significant capital investments in its future, an increase appears warranted. Staff proposes a \$251.955 million rate increase and a 9.80% ROE, which gives the Company a reasonable opportunity to earn a fair rate of

return while giving ratepayers access to safe and reliable energy at reasonable rates.

## II. REVENUE DEFICIENCY

Staff initially projected a revenue deficiency of \$247.371 million, a revenue requirement decrease of \$326.696 million from the Company's originally filed revenue deficiency of \$574.067 million found on Exhibit A-11, Schedule A-1, Line 10. (Nichols, 5 TR 4879.) The main factors driving Staff's overall adjustment are Staff's lower rate base, its higher net operating income, and its lower required rate of return. (*Id.*) In this brief, Staff has updated its case and now projects a revenue deficiency of \$251.955 million, a revenue requirement decrease of \$322.113 million from the Company's originally filed revenue deficiency of \$574.067 million. (Appendix A, Line 11.) A reconciliation of the updates Staff has made in this brief can be found in Appendix F, Lines 14-41.

The \$322.113 million difference between the Company's proposed total revenue deficiency of \$574.067 million and Staff's proposed total revenue deficiency of \$251.955 million is due to the following adjustments (revenue requirement impact in millions):

Rate Base	\$ (29.359)
Rate of Return	(133.334)
Revenue	(6.486)
O&M	(112.468)
Depreciation	(28.453)

Property Tax	(3.698)
Return on Tree Trim Reg. Asset	(7.062)
Return on Monroe Reg. Asset	<u>(1.253)</u>
<b>Total Staff adjustments (rev. req. impact)</b>	<b>\$(322.113)<sup>1</sup></b>

### III. RATE BASE

“Rate base consists of the capital invested in utility plant, less accumulated depreciation [i.e., net plant], plus the utility’s working capital requirement.” *In re Detroit Edison’s 2010–2011 Rate Case*, MPSC Case No. U-16472, 10/20/2011 Order, p. 5. In this case, rate base also includes net capital lease property, net nuclear fuel property, less: capital lease obligations.

#### A. Staff recommends a total rate base of \$23.170 billion.

Staff recommends a total rate base of \$23.170 billion, which is \$390.346 million less than the Company’s initial projection of \$23.561 billion. Staff’s net plant is \$384.522 million lower than the Company’s because Staff adjusted the Company’s: 1) production; 2) distribution; 3) demand side management; 4) information technology; 5) corporate staff; 5) and charging forward capital expenditures. (Appendix E.) Staff’s capital expenditure adjustments are detailed in Section III.B. Staff also reduced working capital by \$5.824 million for other

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<sup>1</sup> Appendix A, line 11; Calculations of impacts Appendix F, lines 1-13.

accounts receivable. (Appendix E.) Staff's working capital adjustment is detailed in Section III.A.5.

**1. Staff recommends a net utility plant of \$21.593 billion.**

The first component of rate base is net utility plant. Net utility plant consists of total utility plant minus accumulated depreciation and amortization. Staff's recommended total net utility plant is \$21.953 billion. (Appendix B, Line 8.) Staff's proposed net utility plant is \$384.522 million lower than the Company's net utility plant of \$21.978 billion because of a \$407.432 million reduction to plant in service, and a \$22.910 million increase to accumulated depreciation and amortization. (Appendix B, Lines 2-8, Column d; Appendix E, Line 92, Columns c, d, e.)

**a. Staff recommends a total utility plant of \$28.493 billion.**

The first component of net utility plant is total utility plant. (Appendix B, Line 6, Column e.) Staff recommends a total utility plant of \$28.493 billion, which is \$407.432 million less than the Company's initial projection of \$28.900 billion. (See Section III.B. below and Appendix E for the capital expenditure adjustments.)

**b. Staff recommends an accumulated depreciation and amortization reserve of \$6.900 billion.**

The second component of net utility plant is the accumulated depreciation and amortization reserve. (Appendix B, Line 7, Column e.) Staff recommends accumulated depreciation of \$6.900 billion, which is \$22.910 million more than the company's initial projection of \$6.923 million. (Section III.A.1.b. and Appendix E.)

**2. Staff recommends net capital lease property of \$5.735 million.**

The second component of rate base is net capital lease property. Staff recommends the Administrative Law Judge (ALJ) and the Commission adopt the Company's projection of \$5.735 million. (Appendix B, Line 9, Column e.)

**3. Staff recommends net nuclear fuel property of \$207.030 million.**

The third component of rate base is net nuclear fuel property. Staff recommends the ALJ and the Commission adopt the Company's net nuclear fuel property of \$207.030 million. (Appendix B, Line 11, Column e.)

**4. Staff recommends capital lease obligations of \$5.815 million.**

The fourth component of rate base is capital lease obligations. Staff recommends the ALJ and Commission adopt the Company's projection of \$5.815 million. (Appendix B, Line 13, Column e.)

**5. Staff recommends a total working capital of \$1,369,559,000 (approximately \$1.370 billion).**

**[References in the Record:** Company witness Uzenski, A-12, Schedule B4; Staff witness Hecht, 5 TR 4888, S-2, Schedule B1; Staff witness Witt, 5 TR 4895-4896, S-2, Schedule B4; AG witness Coppola (Revised), 4 TR 3421, 3478-3482, AG-21.]

The fifth component of rate base is working capital. The Company forecasted that its total working capital requirement for the projected test year will be \$1,375,383,000 (approximately \$1.375 billion). (A-12, Schedule B4; Appendix E.) Staff's working capital of \$1,369,559,000 (\$1.370 billion) (Appendix E) is \$5,824,000

(\$5.824 million) less than the Company's because Staff adjusted the other accounts receivable account.

**a. Staff recommends a \$5,824,000 reduction to working capital—other accounts receivable.**

Staff, through its witness Timothy G. Witt, recommended a \$5,824,000 reduction to other accounts receivable. (Appendix B; 5 TR 4895-4896.) The Company, in response to Staff's inquiry, confirmed that the account Other Accounts Receivable has an embedded balance that is considered non-recoverable and non-utility related. (S-21.0.) Based on the record evidence in this case, and the Company's non-objection in rebuttal, Staff recommends that the Commission reduce the projected test year working capital by \$5,824,000.

**B. Staff recommends several reductions to the Company's capital expenditures, along with some approvals.**

As discussed above, Staff's total utility plant is \$407.432 million lower than the Company's because Staff adjusted the Company's: 1) production; 2) distribution; 3) demand side management; 4) information technology; 5) corporate staff; 6) and charging forward capital expenditures. (Appendix E.) The adjustments are explained below.

**1. The Commission should exclude \$31.953 million from DTE's projected production capital expenditures.**

Staff recommends the removal of \$31.953 million in production capital expenditures, which reduces rate base by \$15.718 million. (Appendix E, Line 3, Columns b and e.) The specific exclusions are discussed in the following.

- a. Staff recommends the capital spending associated with Steam—Other—Trenton Channel Battery Energy Storage System (TC BESS) should be reduced by \$31.953 million, and, thus, the Commission should approve costs for the TC BESS, in the amounts identified in the updated revenue deficiency analysis provided by the Company in Exhibit A-56. (Appendix E, Line 2.)**

**[References in the Record:** Company witness Margaret E. Guillaumin, 3 TR 586, 696-698; A-12, Sch B5.1; Company witness Kirk M. Vangilder, 3 TR 1606-1607; A-56; AG witness Sebastian Coppola, 3 TR 3456-3457; Staff witness Jonathan J. DeCooman, 5 TR 5037-5042.]

The Company's application included a request for approval of capital expenditures through the test year for completion of the TC BESS, totaling \$409.8 million. (3 TR 586.) The TC BESS continues to advance in development towards achieving a commercial operations date in 2026, with the Company presenting updated costs forecasts that further refine the expected final costs and identify the status of all contracts for work on this project. (5 TR 5040.) Significant to this development is the execution of a new battery supply contract, which resulted in a reduction in the forecasted total capital costs for this project of \$31.2 million. (5 TR 5041.) Staff reviewed this contract and recommended the Company include in its rebuttal the revenue deficiency impacts that result from the expected reduction in costs. (*Id.*) The finalizing of the battery supply contract, and the advanced nature

of all other contractual work for the project, provides assurance that the updated costs presented in rebuttal reflect final costs, reducing the expected rate impact of this project by \$2.7 million compared to previous cost estimates. (A-56.)

Staff submits that the Company's Exhibit A-56 is reasonable.

Sebastian Coppola, testifying on behalf of the Michigan Attorney General (AG) Dana Nessel, recommended a partial disallowance of requested capital costs for the TC BESS. The Staff disagrees with the AG witness's recommendation. Witness Coppola's recommended disallowance was composed of two parts. The first adjustment reflects the reduction in overall costs of \$31.2 million previously identified and reflected in the Company's updated revenue deficiency impact, Exhibit A-56. (4 TR 3456.) Witness Coppola also recommends a separate disallowance of an incremental \$33.48 million in project capital costs, associated with three contracts for work, which were not yet finalized. (3 TR 3457.) Witness Coppola claims that costs associated with these contracts are still uncertain and premature. Witness Coppola argues that major changes have occurred during project development and the experimental nature of the technology make further delays in the timing of capital expenditures likely. (*Id.*)

In rebuttal testimony filed, on behalf of the Company, witness Margaret Guillaumin supported the \$31.2 million disallowance identified by Staff and the AG corresponding to the new battery supply contract. (3 TR 696.) The Company provided the revenue deficiency impacts of this change in contract in its rebuttal as recommended by Staff. (A-56.) Witness Guillaumin disputed the additional \$33.48

million disallowance that the AG proposed for costs associated with three unsigned contracts. (3 TR 697.) Witness Guillaumin identified the three remaining unsigned contracts as the continuation of existing contractual work, for owners engineering services and engineering and construction services, and \$0.51 million in costs associated with test energy for commissioning. (3 TR 698.) Witness Guillaumin's rebuttal continues to provide more detail into the nature of this contractual work, arguing it was necessary to complete the TC BESS. (*Id.*) Staff agrees with this assessment. As identified by the Company, all other contracts for work for the project have been completed, and only approximately \$0.5 million of this recommended disallowance is for new contracted work, for test energy for commissioning. (*Id.*) Given the significant developments that have occurred, and the specificity of the currently unsigned work as provided in the Company's rebuttal, the Company has shown that the \$33.48 million for unsigned contractual work is reasonable. The ALJ and Commission should disregard this additional disallowance proposed by the AG and adopt the updated revenue deficiency identified by the Company in Exhibit A-56.

**2. The Commission should exclude \$531.339 million from DTE's projected distribution capital expenditures. (Appendix E, Line 46.)**

Staff recommends four categories of adjustments to distribution capital expenditures, i) distribution base capital program; ii) distribution strategic capital – infrastructure resilience and hardening; iii) distribution strategic capital –

infrastructure redesign and modernization; iv) distribution strategic capital - technology and automation.

As a general matter on capital expenditures, in direct testimony, ABATE<sup>2</sup> witness Jessica York recommended the Commission only allow the projected capital expenditures associated with projects that are expected to be in-service during the bridge period and projected test year. If adopted, this would result in a \$829.311 million disallowance to distribution capital expenditures for the bridge period and projected test year.

Staff does not agree with this recommendation. In previous orders, the Commission has rejected adjustments based on in-service dates. (5 TR 5294-5295.)

- a. Capital spending associated with distribution base capital program should be reduced by \$143.824 million. (Appendix E, Lines 6-8.)**

Staff recommends capital expenditures for distribution base capital program should be reduced by \$143.824 million, which reduces rate base by \$103.661 million. (Appendix E, Lines 6-8.) This is composed of three adjustments (the first is a combination of 2 line adjustments) described below.

- i. Staff recommends emergent replacement capital expenditures should be reduced by \$101.610 million, which reduces rate base by \$73.243 million (Appendix E, Line 6) and recommends customer connections, relocations and other capital expenditures should be reduced by \$29.370 million, which**

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<sup>2</sup> ABATE stands for Association of Businesses Advocating Tariff Equity.

reduces rate base by \$21.170 million.  
(Appendix E, Line 7.)

**The Commission should disallow the historical five-year inflation adjustment to Emergent Replacements program and the historical three-year inflation adjustment to Customer Connections, Relocations and Other program.**

[References in the Record: Staff witness Ally Durfee, 5 TR 5273; Company witness Timothy Lyons, 4 TR 3183-3184, 3195-3196; Company witness Hill, 4 TR 2808, 2821, 2825; AG witness Coppola, 4 TR 3434; ABATE witness Jessica York, 4 TR 3260-3262; MNC witness Douglas Jester, 5 TR 4763-4770.]

Staff witness Ally Durfee argues that there is still not a consistent trend upward of cost categories within the Emergent Replacement or the Customer Connections, Relocations and Other programs and the Company did not provide a convincing argument that it is necessary to inflate the numbers for the historical years. (5 TR 5273.)

Company witness Timothy S. Lyons rebuts this argument by stating that the company provided evidence showing costs for materials commonly replaced as part of Emergent Replacements have increased consistently over the past several years. He also stated that contract labor rates have increased over the past several years. (4 TR 3183.)

Company witness Brian L. Hill also rebuts this argument by stating the Company has provided substantial evidence of volatility and upward cost trends in the instant case. (4 TR 2821.) AG witness Sebastian Coppola states that if any inflation was experienced in prior years, it is reflected in the actual amounts paid. He points to where the Commission rejected the Company's proposal in the January 23, 2025 Order for MPSC Case No. U-21534. 1/23/25 Order, pp. 73-74. Witness

Coppola concludes that the Company has not provided any new compelling evidence that Constant Dollar Averaging should be adopted. (4 TR 3434.)

Company witness Lyons rebuts the AG's arguments, stating the Company provided evidence in direct testimony to address the commission's suggestion to demonstrate how the expenditure categories were both volatile and consistently trending upward. (4 TR 3184.)

Company witness Hill also rebuts the AG's arguments stating that he and Company witness Lyons "provided substantial evidence of volatility and upward trends in costs to support the use of CDA in the instant case" and that "these facts directly support the use of constant dollar averaging." (4 TR 2808.)

ABATE witness York proposes using an uninflated average as a starting point for the development of DTE's future test year projections. Witness York states the uninflated five-year historical average recognizes both increases in material and labor costs and uncertainty around the volume of work that will be required. (4 TR 3260-3262.)

Company witness Lyons rebuts ABATE's arguments by stating that the company has provided evidence that addressed the Commission's suggestion to demonstrate how the expenditures categories were both volatile and consistently trending upward. He also states that the uninflated historical average does not account for increases in material/labor costs over time due to inflation. (4 TR 3195-3196.)

Company witness Hill also rebuts witness York's arguments, stating Company witness Lyons notes in his direct testimony that constant dollar averaging of historical costs is a necessary step in developing cost forecasts because inflation over time reduces the purchasing power of goods and services. (4 TR 2825.)

MNC<sup>3</sup> witness Douglas B. Jester proposes that the Commission reject the proposal to recover non-storm restoration expense based on constant dollar averaging and use average historical costs and apply a forward inflation escalation to determine projected test-year estimates. Witness Jester states nominal dollar averaging does not lose purchasing power over time due to inflation in a cumulative sense. Nominal cost averaging over multiple rate cases will produce a higher cost average. He also states, in testimony, an upward trend in Distribution Operations Labor rates does not justify constant dollar averaging and 2 out of 3 examples the Company shared that utilize constant dollar average were under PBR frameworks. (5 TR 4763-4770.)

Company witness Lyons rebuts witness Jester's arguments stating nominal dollar averaging understates the real level of costs when older year costs are included without inflation adjustments and he states that the nominal average cost would continue to be understated in future rate cases as it would not reflect the "real" dollar value of historical costs. Witness Lyons also states that the importance

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<sup>3</sup> Michigan Environmental Council, Natural Resources Defense Council, and Citizens Utility Board of Michigan, is collectively identified as MNC.

of utilizing constant dollar averaging of historical costs is relevant and important regardless of the ratemaking mechanisms. (4 TR 3195.)

Company witness Hill also rebuts, stating the Company disagrees with the claim that there has not been an upward trend in Distribution Operations labor rates that justifies constant dollar averaging. He states, in testimony, contract labor costs increased significantly since 2019 and that witness Jester overlooks material cost. (4 TR 2808.)

In preparing Staff's brief, a calculation error was discovered, and this brief corrects Staff's disallowance for the Customer Connections, Relocations & Other program from \$23,980,000 for 2025 and \$24,730,000 for the test year to \$14,460,000 for 2025 and \$14,910,000 for the test year. Staff maintains that constant dollar averaging should not be used. There is no consistent upward trend in cost categories for the Emergent Replacement or the Customer Connections, Relocations and Other programs and there is no convincing argument as to why the Company should inflate the historical average.

- ii. **Staff recommends electrical system equipment – projected meters capital expenditures should be reduced by \$12.844 (\$6,301,228 in 2025 and \$6,542,690 in 2026 for Projected Meters), which reduces rate base by \$9.248 million. (Appendix E, Line 8.)**

**[References in the Record:** Staff witness Hansen, 5 TR 5168-5171, S-22.0, S-22.1; Company witness Hill, 4 TR 2827-2829.]

In Staff's direct testimony, Staff witness Hunter Hansen recommended a disallowance for the Company's requested recovery of Projected Meters expenses. (5

TR 5169.) Staff recommended this disallowance because the Company purchased a surplus of meters in 2024 because there was an increase in meter failures in 2023 and supply chain lead times were extended to 12-15 months. (*Id.*) Because this surplus of meters is expected to be delivered throughout 2025 and 2026, it should be expected that the Company would purchase less meters throughout 2025 and 2026 to make up for the surplus of incoming meters. In rebuttal, Company witness Brian L. Hill testified as the follows, “The purchase volume of meters in 2024 (70,000) was necessary to maintain adequate inventory to meet customer needs and balance its meter inventory.” (4 TR 2828.) Staff testified to clarify this statement in light of the facts at issue. The Company purchased 115,661 meters in 2024, not 70,000, which is the surplus number of meters purchased in 2024. (5 TR 5170.)

Additionally, the Company stated that this surplus of meter purchases was necessary to maintain adequate inventory. However, the Company did not provide any information about its historic or current meter inventory; therefore, there is no way for Staff to review the prudence of the number of meters purchased for this purpose. (Hill, 4 TR 2828.) The Company also included a table that shows that the Company installed 36,000 more meters than it purchased between the years 2021 and 2023; however, again, no information was provided about the meter inventory before, during, or after any of these years is provided. (*Id.*) The Company explicitly stated that the “2025-2026 capital investments for this category are forecasted based on the 3-year historical average actual investments from 2021-2023 plus inflation,” meaning that these projections do not take into account current meter

inventory, surplus meter deliveries, or meter failure trends. (5 TR 5170.) The Staff submits that the Company's projections should take into account the large surplus of meter purchases just one year prior in 2024 rather than just simply being based on the 3-year historic average; therefore, the Commission should make the disallowance recommended by Staff.

After cross examination, Staff became aware of potentially overlapping adjustments regarding the projected meters program. Staff recommends the projected meters adjustment supported by staff witness Hansen be adopted by the ALJ and the Commission. If the Commission were to adopt Staff witness Durfee's inflation adjustment to this area of spend, Staff witness Hansen's adjustment would need to be reduced for the overlap. This would result in adopting a 2025 reduction of \$5,465,228 instead of \$6,301,228 and adopting a 2026 reduction of \$5,680,690 instead of \$6,542,690.

**b. Capital spending associated with distribution base capital program – infrastructure resilience and hardening – PTMM should be reduced by \$200 million.**

**[References in the Record:** Staff witness Ryan Boutet, 5 TR 4973, 5148; S-8.0 p. 4, S-8.1.]

Staff recommends capital expenditures for distributional strategic capital program—infrastructure resilience and hardening—pole top maintenance and modernization (PTMM) should be reduced by \$200 million, which reduces rate base by \$97.962 million. (Appendix E, Line 12.)

Through Staff's witness Ryan Boutet, Staff recommended capital expenditures for distribution strategic capital program—infrastructure resilience hardening—pole top maintenance and modernization (PTMM) should be reduced by \$200 million, which reduces rate base by \$97.952 million (Appendix E, Line 12.)

The Company's IRM Alternative 2026, if adopted by the Commission in full or in part, would shift a portion of the revenue deficiency requested by the Company to the IRM surcharge calculation. As provided by the Company, the Commission's adoption of the full IRM Alternative 2026 would reduce its requested revenue deficiency by approximately \$18.6 million. (5 TR 4973; S-8.0 p. 4, S-8.1.)

Since staff is recommending \$200 million for pole and PTMM be moved into the Company's 2026 IRM Staff's brief reflects removal of the project from the case. (Boutet, 5 TR 5148; Appendix E, line 12.)

**Staff supports the Company's proposal for funding and program specifications of the Pole and Pole-Top Maintenance and Modernization (PTMM) program, as well as its inclusion in the Company's Infrastructure Recovery Mechanism (IRM) for calendar year 2026.**

[References in the Record: ABATE witness James Dauphinais 4 TR 3386-3387, 4 TR 3396-3403; Staff witness Ryan Boutet 5 TR 5146-5148, 5 TR 5153-5154; Sheilendranath 3 TR 1084; Company witness Bill Chiu, 3 TR 1110, 3 TR 1154-1155; Willis 4 TR 1744, 1747, 1755-1756, 1767-1769; Company witness Joseph Robinson 4 TR 1933-1948, 4 TR 2040-2043, A-23 Schedule M11, A-23 Schedule M13; ABATE witness Colin Fitzhenry, 4 TR 3356, 3365-3367.]

Company witness Joseph Robinson provided support for the Company's proposal to implement inspection cycles recommended by the Liberty Audit, consisting of a 5-year pole-top inspection cycle and a 10-year pole inspection cycle, as directed by the Commission in Case No. U-21534. (4 TR 1937-1939.) MPSC

Case No. U-21534, 1/23/25 Order, p. 108. This proposal included a request to increase PTMM spending for 2026 to \$200 million (4 TR 1943) and to include this program into the IRM as requested by Company witness Willis (4 TR 1744.) Staff supports the entirety of the Company's proposals involving PTMM specifications and IRM funding, as the specifications are consistent with recommendations made in the Liberty Audit in Case No. U-21305 (5 TR 5147), and the funding levels appear necessary given that the Company was unable to sustain a 20-year pole inspection cycle with historic funding according to the Liberty Audit. (5 TR 5154.) MPSC Case No. U-21305, 9/23/2024 Report, Filing No. U-21305-0013, p. 43.

**Staff disagrees with the position of ABATE witness James Dauphinais to reject the Company's proposal to add the PTMM cost category to the IRM in this proceeding.**

[References in the Record: Dauphinais 4 TR 3386-3387, 4 TR 3396-3403; Boutet 5 TR 5146-5148, 5 TR 5153-5154; Sheilendranath 3 TR 1084; Chiu 3 TR 1110, 3 TR 1154-1155; Willis 4 TR 1744, 4 TR 1747, 4 TR 1755-1756, 4 TR 1767-1769; Robinson 4 TR 1933-1948, 4 TR 2040-2043, A-23 Schedule M11, A-23 Schedule M13; Fitzhenry 4 TR 3356, 4 TR 3365-3367.]

ABATE witness Dauphinais recommended that the Commission completely reject the Company's proposed addition of the PTMM program into the IRM in this proceeding. (4 TR 3402.) Company witness Willis responded that Dauphinais' concerns about relitigating the PTMM issue are invalid, as one of the major takeaways from the Liberty Audit was the importance of the PTMM program, which has been discussed in detail by Company witness Robinson as new information in this case, negating any issue of relitigating a topic from a past rate case. (4 TR 1769.) Furthermore, as discussed in the following section, Company

witness Robinson explains that the BCA model and its supporting data for the PTMM program have been developed specifically in response to audit recommendations. (4 TR 2040.) Staff concurs that the BCA model has been developed to respond to specific concerns in the Liberty Audit report, and that the proposed funding and specifications by the Company will be necessary to implement new inspection cycles for the PTMM program. (5 TR 5154.)

**Staff disagrees with the position of ABATE witness Colin Fitzhenry to reject the Pole and Pole-Tip Maintenance and Modernization program from the IRM and maintain its funding at historical 2025 level adjusted for inflation.**

**[References in the Record: Dauphinais, 4 TR 3386-3387, 3396-3403; Boutet, 5 TR 5146-5148, 5 TR 5153-5154; Sheilendranath 3 TR 1084; Chiu 3 TR 1110, 3 TR 1154-1155; Willis 4 TR 1744, 4 TR 1747, 4 TR 1755-1756, 4 TR 1767-1769; Robinson 4 TR 1933-1948, 4 TR 2040-2043, A-23 Schedule M11, A-23 Schedule M13; Fitzhenry 4 TR 3356, 4 TR 3365-3367.]**

ABATE witness Colin Fitzhenry called for an adjustment to reduce PTMM investments for the period 2026-2029 to 2025 levels, only adjusting for inflation, until program efficiency can be improved or the Company can produce better data. (4 TR 3367.) More specifically, witness Fitzhenry references the Liberty Audit report to state that the Company lacks reliable data from which to accurately estimate PTMM costs. (4 TR 3356.) The Company disagreed with this stance, seen in the rebuttal testimony of witness Robinson. Witness Robinson explained that the supporting data and models used for PTMM, such as the Benefit Cost Analysis conducted by Company witness De Stigter, were developed after the audit was completed, specifically in response to audit recommendations. (4 TR 2040.) Staff witness Boutet concurs that the BCA analysis has been developed to respond to

specific concerns in the Liberty Audit report, and that the spending increases as proposed by the Company will be necessary to implement new inspection cycles associated with the PTMM program. (5 TR 5154.)

**Staff disagrees with the position of AG-MN witness Stephens to slow the pole-top inspection cycle of the PTMM program to 10 years, as opposed to the 5-year cycle proposed by the Company.**

[References in the Record: Robinson, 4 TR 2035-2039; Stephens, 5 TR 4518-4533; Boutet 5 TR 5146-5148, 5152-5153.]

AG-MN<sup>4</sup> witness Dennis Stephens recommends that the Commission should order the visual pole-top inspection frequency to be relaxed from once every five years to once every ten years, implying that the opportunity for reliability improvement is simply not that significant. (5 TR 4532.) Witness Stephens further identifies, in his testimony, that among outages categorized as equipment, field note references to pole and pole top equipment are extremely rare. (5 TR 4531.) The Company disagreed with this stance through the rebuttal testimony of Company witness Joseph Robinson, who identifies that this suggestion contradicts a specific recommendation from the Liberty Audit to adopt a four-to-five-year visual overhead circuit inspection program. (4 TR 2036.) Company witness Robinson further identifies that no analysis was provided by witness Stephens to support his recommendation, rather witness Stephens leaned on personal experience as opposed to benchmarking done by the Company. (4 TR 2037.) Company witness Robinson lastly identifies in rebuttal that witness Stephens' recommendations are in direct

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<sup>4</sup> Attorney General Dana Nessel, Michigan Environmental Council, and Natural Resources Defense Council are collectively referred to as AG-MN.

conflict with the guidance issued by the Commission in its January 23, 2025 Order in Case No. U-21534 at page 108. (4 TR 2038.) Indeed, Staff agrees that this recommendation conflicts with prior Commission guidance in Case No. U-21534, and also in Case No. U-21305 where the Commission explicitly adopts Liberty's recommendation and agrees that this effort to reach a four-to-five-year visual inspection cycle should be accelerated. (5 TR 5153.) MPSC Case No. U-21305, 6/12/2025 Order, p. 23; MPSC Case No. U-21354, 1/23/2025 Order, p. 108.

**Staff disagrees with the position of AG witness Sebastian Coppola to disallow funding for a particular set of Substation Risk Projects.**

[References in the Record: Ryan Boutet, 5 TR 5154-5155; Sebastian Coppola 4 TR 3449-3451; AG-5; Robinson, 4 TR 1997-2022, 2046-2048.]

AG witness Sebastian Coppola recommends that the Commission disallow \$27.104 million in 2025 and \$5.625 million in 2026 for the following named Substation Risk Projects: Apache, Chestnut, Drexel, Hood, and McGraw. (4 TR 3449.) Witness Coppola argues, in testimony, that the Company has not adequately justified or quantified a significant improvement in reliability or that the investment will provide a net financial benefit to customers. (4 TR 3449-3450.) The Company disagreed with this recommendation through the rebuttal testimony of Company witness Joseph Robinson, who explains that Coppola's disallowances disregard the way the Company supports its investments in Substation Risk Projects. (4 TR 2047.) Robinson details that these projects are focused on repairing existing substation failures and preventing future catastrophic failures, events which can cause outages for all customers supplied by the substation. (4 TR 2047.) Witness Robinson lastly details some ambiguities surrounding discovery requests

sent to the Company by the Attorney General, and disagreement with the AG request for a benefit cost analysis on failed substations, such as the McGraw substation which has been on temporary solutions since 2021, would not provide any useful conclusions. (4 TR 2048.) Staff concurs that these investments should not be disallowed, having reiterated the impact of substation failure events and restoration efforts, and pointing to the current temporary solutions and vulnerabilities of the McGraw Substation. (5 TR 5155.) Of further note, the Company identified that it selects Substation Risk Projects such that substations that cannot be entirely restored by a mobile fleet asset are prioritized, which Staff finds to be a reasonable and logical decision-making process. (5 TR 5155.)

**Staff supports the inclusion of the Company's Small Wire Replacement Program as part of the Infrastructure Resilience and Hardening pillar and recommends the Commission request further details on this program if the Company seeks to continue it.**

[References in the Record: Robinson 4 TR 1947-1951; Boutet, 5 TR 5145-5146.]

Staff expressed support for the Company's Small Wire Replacement Program as introduced by Company witness Robinson, as the Company provided compelling evidence that small wires may be contributing largely to wire down events. (5 TR 5146.) Furthermore, it is identified that this program will focus on the 4.8kV system which contains some of the oldest infrastructure and highest safety risks and should therefore contribute to both reliability and safety improvements. (5 TR 5145-5146.) Staff suggests the Commission allow the Company to fund this program at \$10 million in the test year. If the Company seeks to continue this

program in future rate cases, Staff expects an accompanying analysis to discuss lessons learned in terms of pacing, scalability, cost per mile, and wire down improvement metrics related to this program. (5 TR 5146.) No other parties opposed or rebutted this recommendation.

**c. Capital spending associated with distribution strategic capital program—technology and automation should be reduced by \$156.052 million. (Appendix E, Lines 37-45.)**

**[References in the Record:** Company witness Stephen Rademacher, 3 TR 758, 782-785, 906, A-12, Schedule B5.4; A-23, Schedule M6; A-23, Schedule M7; Company witness Stowe, 2 TR 60, 74 176, 189-201; Staff witness Jing Shi, PE (Revised), 5 TR 4995-5030; S-10.1, STDE-7.1b; S-10.1, STDE-6.9a; S-10.2, S-10.4; S-10.1, STDE-6.24.a., S-10.1, STDE-6.25a.]

As testified to by Staff witness Jing Shi, PE, Staff recommend capital expenditures for distribution strategic capital program – technology and automation should be reduced by \$156.052 million, which reduces rate base by \$105.642 million. (Appendix E, Line 37-45.) Witness Shi’s testimony supports this Section III.B.2.c. as well as Section III.B.2.d. below. (Appendix E, Lines 37-45; Appendix E, Lines 14-36.)

**i. CVR/VVO program (A-12 Schedule B5.4, Page 14, Line 2) (Appendix E, Line 38)**

Conservation Voltage Reduction (CVR) and Volt Var Optimization (VVO) are key components of the Company’s Grid Automation, which is centered on developing the physical technology infrastructure necessary to support the efficient control and operation of a modern distribution grid.

As Company witness Stephen P. Rademacher explained:

The CVR/VVO Program involves replacing end of life pole top capacitor controls with modern SCADA [Supervisory Control and Data Acquisition] enabled controls that include sensors and asset health measurement. It also entails upgrades to selected substation Load Tap Changer (LTC) Controllers to coordinate with the pole top devices through the ADMS [Advanced Distribution Management System] CVR/VVO control capabilities. ADMS CVR/VVO allows for pole top and LTC data to be analyzed in real time with a circuit model that computes voltage changes every few minutes and adjusts the device controls dynamically for each circuit to provide the optimal configuration as opposed to each device operating independently. [3 TR 782.]

According to Company witness Bill Chiu (A-23 Schedule M8, page 240), the initial CVR/VVO pilot was completed in 2022, then the program was paused in 2023 and resumed in 2024. Upon resumption, the Company focused on completing delayed projects originally scheduled for 2022 and replacing capacitor control equipment. Beginning in 2025, the program is expected to shift toward full SCADA (Supervisory Control and Data Acquisition) enablement and system-wide optimization.

DTE provided the historical and projected expenditures in Exhibit A-12, Schedule B5.4, page 14, line 2. Staff supplemented these projected expenditures through discovery in Exhibit S-10.2. They are as follows:

2019:	\$32,000
2020:	\$960,000
2021:	\$4,603,000
2022:	\$5,164,000
2023:	\$2,020,000

2024: \$2,519,000

2025: \$2,900,000

2026: \$10,100,000

For the year 2025, the Company plans to upgrade 22 circuits, which includes replacing 50 capacitors, associated controls, and two regulator controls. In 2026, the Company intends to upgrade an additional 40 circuits and replace 80 capacitors. However, Staff has expressed concern regarding the feasibility of the projected \$10.1 million expenditure for 2026, considering that as of May 2025, only \$426,000 had been expended, with 9 capacitors installed or upgraded across 6 circuits (S-10.1, STDE-7.1b). Nonetheless, Staff also considered the Company's expenditure levels from 2023 and 2024, which are consistent with the 2025 projections.

In its discovery response (S-10.1, STDE-7.1e), the Company states that it intends to install capacitors on 70 circuits in 2026; however, no detailed explanation has been provided to substantiate the \$10.1 million projected cost for that year.

Staff does not recommend any adjustment to the 2025 expenditure. However, for 2026, Staff recommends adjusting the Company's projected expenditure. Using the Company's 2025 projection of \$2,900,000 and adjusting for inflation at a rate of 2.66%, the reasonable projected expenditure for 2026 is estimated at \$2,977,140. Therefore, Staff recommends a disallowance of \$7,122,860 from the 2026 projection (\$10,100,000 – \$2,977,140).

In DTE's rebuttal testimony, witness Rademacher testified that "the lower investment levels from 2023 through 2025 were intentionally chosen to coordinate

with the completion of the ADMS implementation, which provides the optimization logic to the devices in the field.” (3 TR 937.) Staff generally agrees with this explanation; however, Staff merely requested that the Company provide detailed information regarding the work schedule or a clear timeline indicating how the ramp-up of capital expenditures will be executed.

Witness Rademacher also asserted that Staff “doubts the Company’s ability to execute or secure necessary resources for the proposed work scope.” Nevertheless, he failed to explain how the Company plans to mitigate these concerns or demonstrate its ability to overcome the perceived resource constraints. Without such details, Staff’s assessment remains reasonable and accurately reflects the basis for the adjustment.

Once again, this adjustment is grounded in the Company’s lack of demonstrated execution capacity and the absence of sufficient justification for the proposed ramp-up in circuit upgrades and capital investment.

**ii. *Distribution Automation (part of IRM) (A-12 Schedule B5.4, page 14, Line 3; Appendix E, Line 39)***

The Distribution Automation (DA) program, initiated in 2021, is designed to enhance outage response and improve electric grid reliability, particularly during severe weather events. This improvement is achieved through the deployment of SCADA-enabled reclosers and advanced automation technologies across electrical circuits.

More specifically, as Company witness Rademacher states:

The Distribution Automation Program within Grid Automation uses digital field sensors and switches along with advanced control and communication technologies to automate or remotely control feeder switching, monitor voltage and equipment health, and manage voltage and reactive power. [3 TR 758.]

DTE provided the historical and projected expenditures on Exhibit A-12, Schedule B5.4, page 14, line 3. Staff supplemented historical amounts in Exhibit S-10.2. They are as follows:

2020:	\$10,000
2021:	\$3,297,000
2022:	\$5,506,000
2023:	\$26,759,000
2024:	\$19,434,000
2025:	\$105,625,000
2026:	\$115,625,000

DTE spent \$7,516,000 in the first four months of 2025.

Following a comprehensive review of the DA program and associated expenditures, Staff concurs with the Company's position that expanding the deployment of reclosers will substantially enhance grid safety and reliability. Staff strongly supports these efforts. However, the Commission's Order in Case No. U-21305, which responded to the Liberty Audit Report, stated the Company should slow down its automation program. In that Order, the Commission requested that DTE include the following when it filed its next distribution system plan:

The plan should also describe planned timing for Viper recloser installation on the 4.8kV system for safety at the substation exits and for reliability beyond the substation exits and include an assessment

that compares tree trimming and other alternative measures for providing safe, reliable service so that the prioritization of expenditures to improve reliability cost effectively may be more clearly discerned. [MPSC Case No. U-21305, 6/12/2025 Order, p. 36.]

Staff recommends that the program's implementation pace should be carefully managed. This recommendation is particularly salient given that, as of the time of review, DTE Electric Company had expended only \$7,516,000 of the \$105,625,000 projected for the DA program for all of 2025 in the first four months of 2025.

While the Commission approved the 2025 DA expenditure in its Order issued on January 23, 2025, for Case No. U-21534, it subsequently adopted the Liberty Audit Report's recommendations on June 12, 2025, advising a more measured pace for the DA program. Staff supports the directives set forth in both Case No. U-21534 and Case No. U-21305 and based on the Company's actual spending performance, believes that DTE may be unable to execute the full projected spending within the year. Therefore, Staff recommends aligning the program's budget forecast with DTE's demonstrated spending capability, in line with the Commission's latest directives.

To that end, Staff has reviewed DTE's actual expenditures for the first four months of 2025—\$7,516,000—and projects a total annual expenditure of \$22,548,000 ( $\$7,516,000 \times 3$ ), assuming linear monthly spending. Based on this forecast, Staff recommends a disallowance of \$83,077,000 from the originally projected \$105,625,000 for 2025.

For 2026, applying a 2.66% inflation factor, Staff projects an expenditure of \$23,147,777 ( $\$22,548,000 \times 1.0266$ ) and recommends a disallowance of \$92,477,233 from the requested amount of \$115,625,000.

In his rebuttal testimony, witness Rademacher proposed the following approach to counter Staff's recommended disallowance:

- (1) Start with the seven-month 2025 investment of \$25.3 million and apply a linear monthly investment pattern similar to Witness Shi, but project forward using July investment levels of \$11.3 million per month to estimate a year-end total of approximately \$81.7 million; and
- (2) Follow the Company's detailed ramp-up plan to achieve the full \$105.6 million as approved in Case No. U-21534 and requested in the current case, which the Company believes provides the most accurate forecast. [3 TR 906.]

Staff disagrees with both of these proposals for the reasons stated in Staff Witness Shi's revised direct testimony. However, Staff is willing to adjust the 2025 annual spending level to \$43,371,429 (calculated as  $\$25.3 \text{ million} \times 12 \div 7$ ) based on the Company's actual seven-month expenditure of \$25.3 million. Accordingly, the remaining \$62,253,571 ( $\$105,625,000 - \$43,371,429$ ) should be disallowed for the bridge period.

For 2026, Staff applies a 2.66% inflation factor, resulting in a projected expenditure of \$44,425,109 ( $\$43,371,429 \times 1.0266$ ), and recommends a disallowance of \$71,099,891 from the Company's requested amount of \$115,625,000.

This recommended disallowance does not affect the \$24.4 million approved for inclusion in the IRM for 2026.

**iii. Distribution Sensing and Monitoring (A-12 Schedule B5.4, page 14, Line 4; Appendix E, Line 40)**

According to Company witness Rademacher:

“Distribution Line Sensors are devices used to monitor the real time status of the distribution system and provide critical information to field personnel and system control room operators to help them better monitor and manage the grid. [3 TR 785.]

This program includes installation of overhead sensors used to detect outages and faults on the overhead as well as underground lines and sending the data directly to the ADMS to speed restoration.

The Company’s projected construction schedule and expenditure, as presented in Exhibit A-23, Schedule M7, page 15, are as follows:

2024:	\$590,671 for 543 line and 300 pole sensors
2025:	\$3,500,000 for 1250 line sensors
2026:	\$2,000,000 for 1550 line sensors

DTE also provides that \$153,000 had been spent in the first four months of 2025 as shown on Exhibit S-10.2.

Staff acknowledges that these sensors are essentially “the eyes and ears of the grid.” (3 TR 786.) They play a critical role in outage restoration by identifying and locating faults, thereby enabling the efficient dispatch of repair crews.

However, given that only a small fraction of the projected 2025 budget was spent in the first four months, Staff considered the likelihood that the Company prioritized other urgent projects or lacked sufficient manpower to execute the

planned expenditures. Based on this, Staff recommends adjusting the forecasted expenditures.

Using 2024's unit cost of \$700.70 per sensor (derived from \$590,670/843 units) and applying a 2.73% inflation factor for 2025, Staff estimated the 2025 cost at \$899,757 [ $\$700.70 \times 1.0273 \times 1,250$  units]. The Company's projection exceeds this by \$2,600,243 ( $\$3,500,000 - \$899,757$ ), which is the amount Staff recommends for disallowance.

For 2026, Staff applied an additional 2.66% inflation adjustment, resulting in an estimated cost of \$1,145,377 [ $\$700.70 \times 1.0273 \times 1.0266 \times 1,550$  units]. This yields a recommended disallowance of \$845,623 ( $\$2,000,000 - \$1,145,377$ ).

Company witness Rademacher stated that the Company had spent \$259,000 through July 2025 and projected to spend an additional \$241,000 to install 156 overhead (OH) sensors by the end of the year. (3 TR 961.) He further indicated that the Company would spend approximately \$2.0 million in December 2025 to purchase materials. However, no purchase orders or other supporting documentation were provided in his rebuttal testimony or in Exhibit A-53, Schedule TT13 to substantiate this claim.

The Company also stated that "the \$2,000,000 figure should include both labor and material costs; the material cost is \$555,341" and that "the Company plans to pre-purchase OH and UG sensors in 2025 for installation in 2026." (A-23, Schedule M7.) While the Company identifies a total purchase expenditure of

\$2,000,000, Staff has not received any purchase order, contract, or other documentation to support this proposed spending.

Based on the available evidence, the Company's actual 2025 spending remains below Staff's projected amount of \$899,757. As for the proposed \$2.0 million material expenditure, Staff finds no basis to conclude that such spending will occur within the current year. Therefore, Staff maintains its disallowance for this program.

**iv. The Commission Should Disallow \$1,880,000 in 2025 and \$6,000,000 in 2026 for the Customer Power Status Visibility Project. (Appendix E, Line 41)**

[References in the Record: Staff witness Hansen, 5 TR 5171-5172, S-22.0 and S-22.2.]

In direct testimony, Staff recommended a disallowance for the Company's Customer Power Status Visibility Project. (5 TR 5171.) This project is for the purchase and installation of Field Area Routers (FARs). (5 TR 5171.) Staff recommends this disallowance because the number of units and unit cost for purchasing and installing these FARs provided by the Company do not align with its projections. (5 TR 5172.) In 2025, given the unit cost and number of units, the total cost should be \$9,120,000, \$1,880,000 less than what the Company is asking for. (*Id.*) In 2026, the Company is only installing half as many FARs as it is in 2025, but it is projecting to spend the same amount; therefore, Staff recommends that the Commission to disallow half of the 2026 projection. (*Id.*) In rebuttal, no

party adequately rebutted Staff's position; therefore, the Commission should make the disallowance recommended by Staff.

**v. Distribution SCADA Historian (A-12 Schedule B5.4, page 14 line 14) (Appendix E, Line 42)**

A Distribution SCADA Historian is a specialized software application that plays a critical role in managing and analyzing operational data. As DTE stated in Exhibit A-23, Schedule M7, page 48:

The SCADA historian is currently funded on a yearly basis and by doing multiyear funding, prices can be locked in. The SCADA Historian is an essential portion of the SCADA software ecosystem, providing long term storage and retrieval for engineers and analysts and the baseline for loading and voltage statistics and analysis including system performance information and telemetry status.

The Company projects an expenditure of \$5 million in 2026 to purchase a multiyear software license upon renewal.

In discovery response STDE-1.2.a (S-10.1) Company witness Rademacher explained:

The 2026 capital expenditure is \$5,000,000 for the Distribution SCADA Historian. The acquisition is for a single multi-year software license. As such, the expenditure cannot be itemized by unit price or quantity installed. The full allocation is categorized under "material," with no associated labor or hardware costs. This investment supports the long-term operational integrity of the SCADA system by enabling secure, high-volume data storage and retrieval for system performance monitoring, telemetry analysis, and compliance reporting.

As stated by Company witness Rademacher in his rebuttal testimony:

However, the Company explained the nature of the request (\$5 million for SCADA Historian software license renewals); the vendor's name, the 'basis for the request,' and the invoice for the \$5 million request were not requested in discovery. The absence of these inquiries should not form the basis for disallowance. [3 TR 952.]

Staff's intent is not to intervene in the Company's business decisions but rather to ensure that the funds requested by DTE are appropriately justified and used for their intended purpose. While the Company provided certain information in its rebuttal and in Confidential Exhibit A-53, Schedule TT5, this documentation does not sufficiently demonstrate that the \$5 million expenditure is supported by verifiable contractual or financial commitments.

Given that this represents a substantial expenditure, Staff expects the Company to provide a purchase order, vendor agreement, or invoice to substantiate the cost. Staff's position is that both the Commission and ratepayers deserve full transparency prior to approval of such an expense. Accordingly, Staff recommends disallowing 50 percent of the requested amount (\$2.5 million) pending submission by the Company of appropriate documentation—such as a renewal invoice or executed purchase agreement—confirming the validity of the expenditure.

**vi. Mobile Equipment Replacement (A-12  
Schedule B5.4, page 14 line 38; Appendix E,  
Line 43)**

According to Company witness Rademacher, DTE has deployed thousands of mobile devices for field personnel and their leadership and is replacing them on a six-year cycle.

As Company witness Chiu stated in Exhibit A-23, Schedule M8, page 161, the Company projected the following expenditure:

2024:	\$2.8 million
2025:	\$2.8 million

2026: \$1.4 million

However, other exhibits (A-23, Schedule M2, p. 9, Exhibit A-23, Schedule M3, p. 9) project \$881,000 in 2024 and \$2,800,000 in 2025, with no spending in 2024 and no anticipated spending in 2025. Company witness Rademacher, in Exhibit A-23, Schedule M7, page 145, projected \$3.5 million in 2026.

In the Company's rebuttal testimony, witness Rademacher stated:

The 2026 request is not an overallocation of a single year but the first major replacement cycle after a multi-year pause, addressing more than 1,900 devices that are outdated or past End-of-Life. [3 TR 954.]

Staff fully understands the Company's need to replace ageing and obsolete devices. However, Staff also notes that the funds approved by the Commission in prior years for similar mobile device replacements were not utilized for that purpose. Consequently, Staff requested that the Company provide a detailed explanation of why those previously authorized funds were not spent on device replacements.

Given that the Company has requested additional funds for mobile device replacement in prior years but did not expend them, Staff cannot verify the necessity of replacing all 1,556 field iPads, 75 mobile data terminals (MDTs) without electric docks, and 354 MDTs with electric docks within a single year. To promote prudent investment and fiscal responsibility, Staff recommends replacing only half of these units in the test year. This phased approach would allow the Company to take advantage of potential price reductions, technological improvements, and to explore more cost-effective alternatives in future years.

Accordingly, Staff recommends that the Commission maintain the disallowance of \$1,750,000 for this program.

**vii. Mobile Timesheets (A-12 Schedule B5.4, p. 14, Line 49) (Appendix E, Line 44)**

As Company witness Rademacher stated in his direct testimony and in Exhibit A-23, Schedule M7, page 186:

The Mobile timesheet (MTS) project will replace the outdated mobile timesheet application used by Overhead and Underground crews for nearly 20 years. Persisting with the aging system will result in ongoing payroll errors and administrative burdens. [3 TR 871.]

DTE plans to begin the project in 2026 with \$1.4 million in labor costs, completing it in 2027 with a total cost of \$2.0 million. The project will integrate with SAP and Maximo to streamline payroll and budgeting. According to Company witness Rademacher, the \$1.4 million is entirely labor for software development and integration. (S-10.1, STDE-1.2.g.)

As this is a new project, Staff initially sought a detailed justification of the proposed labor costs, including the number of personnel involved and the total work hours required. In the absence of such information, Staff initially recommended disallowing \$700,000, or 50 percent of the projected \$1.4 million expenditure.

However, in the Company's rebuttal testimony, the Company provided additional information regarding the project's scope and budget. (3 TR 959.) The rebuttal indicated that the project would include \$1.1 million in internal labor for approximately 9,200 hours of work performed by a team of 7 to 9 employees, led by a project manager, to design and deliver a user interface focused on timesheet

functionality. In addition, the Company identified \$300,000 in fixed costs for integration services. Based on this information, the implied average hourly rate for internal labor is approximately \$120 per hour, which Staff finds reasonable for the described scope of work.

Given the supplemental details provided in rebuttal, Staff is satisfied that the Company has sufficiently justified the projected costs and therefore recommends that the Commission approve the full \$1.4 million expenditure for 2026.

**viii. Vegetation Management Replatform (A-12 Schedule B5.4, page 14 line 50) (Appendix E, Line 45)**

This software initiative will replace the existing vegetation management system, which will reach end-of-life in March 2027, with a modern SaaS-based, vendor-hosted solution. The goal is to ensure uninterrupted vegetation management operations with improved data management and scalability.

The project will begin in 2026 and end in 2027. In 2026, the Company projects \$3.2 million (\$2.0 million for labor and \$1.2 million for material), with a total budget of \$4.5 million.

Company witness Rademacher's response to discovery indicates that the Company will need to replace 850 Mobile Licenses, 850 Work Management Licenses, 100 Scheduler Licenses, 5 Administrator Licenses and 6 ArcGIS Pro Licenses in the test year. And roughly \$600,000 is for software licenses and another \$600,000 is for end-of-life hardware replacement. (S-10.1, STDE-1.2.h.)

Staff initially questioned the necessity of procuring such large quantities within a single year, whether the Company pursued bulk purchase discounts, and whether lower-cost alternatives were evaluated. In addition, Staff sought a detailed justification for the projected \$2.0 million in labor costs, including the size of the workforce and the number of hours required. Pending adequate justification, Staff initially recommended a disallowance of \$1.6 million, representing 50 percent of the proposed \$3.2 million allocation for 2026.

In his rebuttal testimony, witness Rademacher provided the following breakdown of costs in response to Staff's inquiries (3 TR 957):

- DTE Electric internal resources: 8,100 hours (approximately \$1 million) covering project management, architecture, IPS security, internal development, data conversion, and user acceptance testing (UAT).
- Contractor support: 2,600 hours (approximately \$280,000).
- External development (vendor): \$400,000 (fixed cost).
- Data conversion/migration (vendor): 2,080 hours (approximately \$250,000).

Staff is satisfied with the additional detail provided in the Company's rebuttal testimony and appreciates the clarification of the project scope and cost structure. Staff also emphasizes that such information should have been included in the Company's initial filing to facilitate a more efficient review process.

Based on the information now available, Staff recommends that the Commission approve the full \$3.2 million expenditure for 2026.

- d. Capital spending associated with distribution strategic capital program—infrastructure redesign and modernization should be reduced by \$31.462 million. (Appendix E, Lines 14-36)**

Staff recommend capital expenditures for distribution strategic capital program – infrastructure redesign and modernization should be reduced by \$31.462 million, which reduces rate base by \$10.186 million. (Appendix E, Lines 14-36.)

**i. Subtransmission Redesign & Rebuild:  
Transformer High Side Protection Program  
(A-12 Schedule B5.4, page 11 line 5) (Appendix  
E, Line 15)**

Company witness Stowe explained in his revised direct testimony, Table 15 that several subtransmission and distribution transformers require high-side protection (either a circuit switcher or breaker) to address NERC-reportable system issues under simulated contingencies that could result in the loss of service to 100+ MVA of customer load. (2 TR 151.) These requirements are in accordance with NERC TPL-001-4 standards.

The program scope includes installing high-side switching devices on 22 transformers at 16 stations and replacing or relocating 10 of those transformers due to space constraints.

DTE provided the historical and projected expenditures (S-10.4; A-12 B5.4, p. 11, line 5); they are as follows:

2020:	\$215,000
2021:	\$1,500,000
2022:	\$1,947,000
2023:	\$2,277,000
2024:	\$1,818,000
2025:	\$6,500,000
2026:	\$5,000,000

As of May of 2025, \$321,000 had been spent.

Staff supports the program's needs but notes the lack of justification for the sharp increase in projected costs for 2025 and 2026, given consistent prior spending.

Staff acknowledges that the Company may catch up later in 2025; nevertheless, that is not guaranteed.

Based on historical averages of \$1,885,500 (2021–2024) and inflation adjustments, Staff recommends disallowances of \$4,563,028 ( $\$6,500,000 - \$1,885,500 \times 1.0273$ ) for 2025 and \$3,011,502 ( $\$5,000,000 - \$1,885,500 \times 1.0273 \times 1.0266$ ) for 2026.

Company witness Stowe stated in his rebuttal testimony that “TTC supports DTE’s efforts to prioritize deployment of high-side interruption protection devices.” (2 TR 189.) Staff does not disagree with this position. Witness Stowe further testified that “the Company has continued to make improvements to its ability to schedule and execute this work and has laid out a sensible schedule for the overall program in Exhibit A-23, Schedule M6, page 21, with execution stretching through 2034.” (2 TR 190).

Staff acknowledges this information and recognizes the Company’s stated intention to continue progressing on this important reliability initiative. Staff also shares the desire to see this program implemented more rapidly. However, given that spending to date has been minimal—as reflected in the expenditures during the first five months of 2025—and that no updated implementation details were

provided in witness Stowe's rebuttal testimony, Staff maintains its position and recommends that the Commission uphold the disallowance previously identified.

**ii. Subtransmission Redesign & Rebuild: Trunk 3509 (A-12 Schedule B5.4, p. 11, line 28) (Appendix E, Line 18)**

The Company's subtransmission system includes both radial and network configurations. A radial configuration, referred to as a trunk line, consists of a single source station feeding one or more substations. Trunk 3509 is currently loaded to 100% of its summer normal rating and 109% of its summer emergency rating, thereby violating the Subtransmission Planning Criteria (A-23, Schedule M6, page 106).

According to the same exhibit, the Company plans to install one breaker, two disconnects, one relay panel, 733 feet of conduit, and replace 6,225 feet of cable, with engineering completed in 2021, design in 2022, and construction from 2023 to 2026.

Historical and projected expenditures are as follows:

2023:	\$2,295,000
2024:	\$1,035,000 (out of \$3,653,000 projected)
2025:	\$2,200,000
2026:	\$473,000

The Company reported \$291,000 in actual spending for the first five months of 2025.

Staff supports the Company's initiative to upgrade Trunk 3509 to improve system shutdown capability and operability. However, the Company has not demonstrated full commitment to completing the program. The 2024 underspending was "primarily due to multiple adjacent hazards along the cable pulling route, which prevented continuation and resulted in unactualized forecasts for cable material and pulling/splicing." (A-23, Schedule M2, page 5, line 18). Furthermore, the Company spent less than 15% of its 2025 projection in the first five months without explanation.

Staff annualized the Company's reported \$291,000 expenditure over the first five months of 2025 to derive a projected annual expenditure of \$698,400 ( $\$291,000 \div 5 \times 12$ ). Based on this projection, Staff recommended a disallowance of \$1,505,600 ( $\$2,200,000 - \$698,400$ ).

In his rebuttal testimony, witness Chiu argued that Staff's linear annualization approach was overly simplistic and did not accurately reflect the nature of capital spending, which typically occurs in non-linear patterns over the course of a project. Staff agrees with this observation and would welcome the opportunity to rely on the Company's more detailed monthly work progress and spending schedules—provided such information is regularly shared with Staff, including in rebuttal or subsequent filings.

However, in this instance, the Company did not provide sufficient updated information in its rebuttal testimony to warrant a revision to Staff's analysis. Therefore, Staff recommends that the Commission adopt the previously proposed

disallowance until the point that additional documentation or schedule details are provided.

**iii. CODI: Alfred Substation Expansion (A-12 Schedule B5.4, page 11 line 31; Appendix E, Line 17)**

According to Company witness Stowe (revised direct testimony, 2 TR 99, Table 7), Alfred (ALFRD) is a two-transformer Class A substation serving Detroit's Central Business District and East Riverfront areas. The City of Detroit Infrastructure (CODI) project seeks to align a new load service with the replacement of aging infrastructure. The Alfred Substation expansion will help eliminate 4.8 kV distribution and 24 kV subtransmission trunk lines in the Midtown area.

The Company reported the following:

- 2023: \$2,893,000 (forecast \$3,183,000)
- 2024: \$10,439,000 (forecast \$18,235,000)
- 2025: \$1,563,000 in the first five months (forecast \$6,000,000)
- 2026 (test year): \$4,210,000

Delays in 2024 were due to fiber route issues, underground interferences, equipment shipment delays, and architectural/electrical design changes impacting the construction sequence.

Staff supports the operational benefits of the project but notes repeated underspending against forecasts. Based on 2025's first five-month spending, Staff annualized \$3,751,200 ( $\$1,563,000 \div 5 \times 12$ ) for 2025, recommending a \$2,248,800 disallowance ( $\$6,000,000 - \$3,751,200$ ).

For 2026, inflating the 2025 allowance by 2.66% yields \$3,850,982, resulting in a \$359,018 recommended disallowance (\$4,210,000 – \$3,850,982).

Company witness Stowe reiterated that “construction activities most often result in the highest spend rates, but must be scheduled based on equipment shutdown schedules, material availability, and other logistical considerations” (2 TR 192). Staff agrees with this statement and recognizes the operational constraints associated with coordinating such construction activities.

However, Staff relies on the Company to provide timely and detailed updates regarding project progress—specifically, information on the completion status of the 2025 scope of work and the amount of capital expended as of the end of August of this year—to evaluate whether the Company remains on track toward achieving its stated goal of \$6.0 million in total expenditures.

Without such updates, the Company’s assurances regarding project execution and spending remain unsubstantiated. Therefore, Staff continues to recommend maintaining the previously identified disallowance until adequate progress and expenditure documentation are provided.

**iv. CODI: Targeted Network Secondary Cable Replacement (A-12, Schedule B5.4, page 11 line 33; Appendix E, Line 19)**

According to Company witness Stowe (2 TR 99), this program replaces targeted 4.8 kV secondary network cables in Detroit that have a higher probability of failure. It is part of the CODI project, aiming to reduce reactive maintenance costs and improve safety, reliability, and power quality.

Per Exhibit A-23, Schedule M6, page 129 annual and projected spends amount to:

- 2024: \$3,868,651 (excluding \$607,949 “Other”) for 10,700 feet
- 2025: \$4,800,000 for 11,500 feet
- 2026: \$3,000,000 for 9,100 feet

DTE spent \$1,751,000 in the first five months of 2025, but footage completed through May 2025 was unknown.

Company witness Stowe also stated: “The Company will replace 12,500 feet of secondary network cable and associated equipment in 2025. Additional details regarding the Targeted Network Secondary Cable Replacement program can be found in Exhibit A- 23 Schedule M6 on pages 126-129.” (S-10.1, STDE-6.9a)

Company witness Stowe further explained in his discovery response that “Other expenditures can include but are not limited to administrative and general (A&G), AFCDC, permitting, procurement, contributions in advance of construction (CIAC), and facilities and fleet services.” (S-10.1, p. 57, STDE-6.1a-x.)

Once again, Staff supports the Company replacing the aged cable to reduce the cable failures’ cost; nevertheless, Staff also needs to make sure that the costs associated with the program are being spent properly.

Staff excluded unclear “Other” costs from 2024 when computing the unit price since the purpose of this “Other” is not relevant to calculate the unit price for 2025 and 2026 since both years’ projection did not include the “Other” costs. The 2024 adjusted cost yields \$301.93/ft, inflated to \$310.18/ft for 2025. Applying this to

11,500 feet results in a \$3,567,041 projection, leading to recommending a \$1,232,959 disallowance for 2025.

For 2026, the inflated unit price is \$318.43/ft. Applying this to 9,100 feet yields \$2,897,697, with \$102,303 recommended to be disallowed.

Even though the Company claimed in the same discovery response that 12,500 feet of network cable is going to be replaced, Staff still projected the 2025 expenditure based on 11,500 feet until and unless the Company provides the actual spending and actual cable feet replacement in their rebuttal.

Once again, the Company makes the claim that it “expects to replace 12,000 feet of secondary network cable and associated equipment in 2026.” (S-10.1, STDE-6.9b.) Staff encountered difficulty following the answer either in the discovery response or the details in Exhibit A-23, Schedule M6 as DTE suggested. Therefore, Staff computed the 2026 projected amount with the details provided in Exhibit A-23, Schedule M6.

In his rebuttal testimony, Company witness Stowe made two primary points. First, he asserted that “Other” costs should be included in the unit cost calculation, even though there are no “Other” costs identified in the Company’s 2025 and 2026 projected expenditures. Second, he noted that the unit costs are presented in Table 4 on the same page, which are derived by dividing the total projected expenditures by the corresponding footage. (2 TR 194.) Staff appreciates the Company’s effort to provide additional clarification.

However, Staff maintains that “Other” costs are not directly relevant to the unit cost calculation in this case, given that no “Other” category expenditures are included in the 2025 and 2026 projections. Staff’s intent is to ensure a fair and consistent “apples-to-apples” comparison across years. If such “Other” costs were relevant, Staff questions why DTE chose not to include them in the projections for those years.

Additionally, while the Company provided unit cost figures, it did not offer sufficient explanation for the notable variability among them—specifically, \$361.56 for 2024, \$417.39 for 2025, and \$329.67 for 2026. Without justification for these fluctuations, Staff cannot validate the reasonableness of the Company’s estimates.

Accordingly, Staff recommends that the Commission maintain the same disallowance amount as identified in Staff’s revised direct testimony.

**v. 4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) (A-12, Schedule B5.4, page 11 of 23, Line 41, 48, 55, 92 and 97), part of IRM (Appendix E, Lines 24, 35, 36)**

Company witness Stowe described this initiative as consolidating and decommissioning 24 kV–4.8 kV substations, transferring load to a new 120 kV–13.2 kV Promenade substation.

He provided in Table 2 of his direct testimony:

The Detroit Economic Growth Corporation has assembled the 186 acres I-94 Industrial Park site. It is part of the 3,203-acre Mt. Elliot Development Zone, which is the single largest industrial district in Detroit and encompasses automotive, metal, transportation, and logistics clusters. It offers access to major transportation assets. The site is a federally designated Historically Underutilized Business Zone

and a state designated Renaissance Zone. Recent new loads were fed from the aging Lynch and Lambert 4.8 kV substations. The new substation is required to serve the load growth in and around I-94 industrial park and allows for decommissioning of the aging Lynch, Lambert, and Pulford 4.8 kV substations. [2 TR 60.]

Staff consolidated the spendings into the following table, which is also partially shown in Exhibit A-23, Schedule M6, page 149:

Line	2023	2024	2025	2026
41	\$ 2,333,000	\$ (508,000)	\$ -	\$ -
48	\$ 4,638,000	\$ 2,508,000	\$ 37,000	\$ -
55	\$ -	\$ -	\$ -	\$ 8,800,000
92	\$ 705,000	\$ 1,165,000	\$ 5,000,000	\$ 16,000,000
97	\$ -	\$ -	\$ -	\$ 500,000
<b>Total</b>	<b>\$ 7,676,000</b>	<b>\$ 3,165,000</b>	<b>\$ 5,037,000</b>	<b>\$ 25,300,000</b>

Staff supports the Company’s purpose in executing this project to further ensure safety and reliability and provide for load to be transferred; however, from 2023 to 2030, work will include pre-conversion, conversion, and decommissioning. The 2026 test-year projection of \$25,300,000 is nearly five times the 2025 amount, without clear justification.

With a similar scope of work from 2023 to 2030, and the details of the jump in projected expenditure unknown, Staff calculated the average of 2023–2025 expenditures at \$5,297,667, inflated to \$5,433,452 for 2026, recommending a \$19,866,548 disallowance (\$25,300,000 – \$5,433,452).

This item, along with Items 13, 19, 20, 21, 22, 23, 24, and 26, are all part of the Infrastructure Recovery Mechanism (IRM) capital expenditures, as shown in the following table:



- Building 0.2 miles of new overhead backbone connection
- Removing 0.5 miles and installing 0.75 miles of new overhead infrastructure
- Rebuilding, pre-converting, and converting ~11 miles of overhead conductor to 13.2 kV.

As Exhibit A-23, Schedule M6, page 193 stated, the Company is going to do the following:

2023 – engineering

2024 – 2025 design and construction of backbone

2026 – conversion and transfer of backbone

On the same page, DTE projected a \$4,424,000 expenditure for the test year.

Staff is in line with the Company's idea to do the conversion; however, phase 2 is a new capital project within the current rate case.

Without further detail on labor hours, manpower, or material specifics, Staff recommends disallowing \$882,000 (20% of the projected cost) pending further justification.

**vii. 4.8 kV CC: Grosse Pointe Substation and Circuit Conversion – North (A-12 B5.4, page 11 line 54) (Appendix E, Line 21)**

This project is part of the broader Grosse Pointe Area plan. Two existing 4.8 kV substations serve approximately 16,400 customers. The average weighted cable age for the trunk lines is about 55 years, and much of the underlying infrastructure exceeds 70 years. The purpose of the project is to address asset age and reliability risk, and to support conversion to a modern 13.2 kV standard for long-term service quality.

For 2026 the Company projects \$1,500,000 categorized as 'labor' associated with property purchase activities (see A-23, Schedule M6, p. 197).

Staff supports the project conceptually but notes that the property acquisition costs require clear itemization and appropriate accounting treatment. The Company has not provided a detailed cost breakdown—such as labor hours, due diligence activities, appraisals, title work, legal expenses, or closing costs—sufficient to substantiate the \$1,500,000 request categorized as “labor.” Accordingly, Staff recommends disallowing \$300,000 of the requested amount pending submission of detailed supporting documentation.

In rebuttal, the Company’s witness clarified that the \$1.5 million amount was mislabeled and should instead be categorized as “Other” (2 TR 195), encompassing property purchase-related activities. However, Staff continues to seek the basis for this \$1.5 million expenditure—specifically, whether there are any preliminary agreements or comparable prior purchases (such as the Grosse Pointe Area plan) that support the estimate.

Absent such documentation or evidence, Staff recommends maintaining the same \$300,000 disallowance until the Company provides sufficient information to justify the proposed expenditure.

**viii. 4.8 kV CC: Melvindale (A-12 Schedule B5.4, page 11 line 56; Appendix E, Line 22)**

The project converts and consolidates three 4.8 kV load-carrying circuits into the 13.2 kV system, with an overall reduction from 37 4.8 kV load-carrying circuits

to 17 13.2 kV circuits. Approximately 12.3 miles of conduit and 59.3 miles of cable will be installed. The plan also includes property purchase, a new 120/13.2 kV substation, expansion of JUPTR, and decommissioning ALNPK, MLVDL, and ECORS.

For 2026, the Company projects \$1,800,000 categorized as 'Other' (A-23, M6, p. 201).

The Company's supporting materials create confusion in cost classification for property acquisition (e.g., treated as 'labor' in related items, and 'Other' here). Absent a detailed purchase contract and a clear accounting treatment, Staff recommends a precautionary adjustment to disallow \$360,000 (20 % of \$1,800,000) unless the Company provides the executed or draft purchase agreement(s), itemized transaction costs, and a clear capitalization policy showing the appropriate classification of property acquisition costs.

Company witness Stowe did not provide any new details or evidence regarding the acquisition; even though he emphasizes that the "Company categorized the projected capital expenditures associated with the property purchase in the Grosse Pointe project and the projected capital expenditures associated with property purchase for the Melvindale project are categorized correctly, the Company follows the accounting policy put forth under the Uniform System of Accounts." (2 TR 196). Staff appreciates his clarification regarding the categorization; however, the details of what the funds will be spent on are still absent. Staff will keep the disallowance in the revised direct testimony.

**ix. System Loading: Jewell (A-12 Schedule B5.4, page 11 of 23, Line 63; Appendix E, Line 23)**

As Company witness Stowe stated, the Company proposes a new 13.2 kV substation to relieve the JEWEL substation and to facilitate the decommissioning of the aging 4.8 kV WSHTN substation.

The Company projected \$1,265,000 for 2023 but spent \$66,000; projected \$592,000 for 2024 but spent less than \$6,000; projected \$364,000 for 2025 in Case No. U-21534; and requests \$2,000,000 in 2026 categorized as 'Other' (A-23, Schedule M6, p. 225).

Given repeated underspending relative to prior projections and limited detail regarding the 'Other' category, Staff lacks confidence that the entire 2026 amount will be timely and prudently executed without additional support. Therefore, \$400,000 is recommended to be disallowed from the \$2,000,000 test year amount unless the Company provides a detailed scope, schedule, and cost breakdown for the 2026 activities along with procurement status for critical path items.

In his rebuttal testimony Company witness Stowe stated:

The 2023 and 2024 underspend was due to difficulty in acquiring a property suitable for a new substation; the Company now plans to repurpose the existing Jewell Substation property, pending ITC approval, and will be able to proceed with the planned 2026 engineering and design that was described in discovery response STDE-6.16a, provided in Exhibit A-50, Schedule QQ3. [2 TR 197.]

Staff finds the Company's updated information reasonable and appreciates the clarification regarding both the reason for the prior underspending and the Company's revised plan to repurpose an existing site. Based on this explanation

and the supporting documentation, Staff recommends that the Commission approve the full projected expenditure of \$2 million for this project.

**x. Subtransmission Redesign & Rebuild: Trunk 7105 (A-12 Schedule B5.4, page 11 of 23, Line 70) (Appendix E, Line 25)**

Trunk 7105 has been overloaded at 133% of normal rating and 127% of the equipment emergency rating during the summer. As Company witness Stowe stated, this overloading violates the subtransmission planning criteria. To prevent the overload problem, DTE is planning to have an Emergency Load Control scheme in place at Brooks Substation and Sargent Substation.

Although no expenditures were initially projected for 2023–2024, the Company spent approximately \$246,000 in 2023 and \$540,000 in 2024 (Exhibit A-23, Schedules M1 and M2). For 2025 the projection is zero; for 2026, \$1,000,000 is categorized as labor.

Staff supports implementing an Emergency Load Control scheme. However, the record lacks a comprehensive budget and explanation supporting the full 2026 request. A measured adjustment is appropriate pending additional detail.

Therefore, Staff recommends disallowing \$200,000 from the \$1,000,000 2026 request unless the Company provides a complete bill of materials with costs, labor plan, and schedule consistent with the stated milestones.

Company witness Stowe asserted that detailed information was provided in Exhibit A-50, Schedule QQ3 (2 TR 198); however, Staff notes that this exhibit does not contain any updated information beyond what was previously submitted.

Therefore, Staff maintains the disallowance as reflected in the revised direct testimony.

**xi. Subtransmission Redesign & Rebuild:  
Reverse Power Relay Scheme Program (A-12  
Schedule B5.4, page 11 Line 71; Appendix E,  
Line 16)**

This program is to improve DTE's operability of their subtransmission system. Currently, the Company operations have to pre-contingent set-up specific areas for load rejection to allow some ITC shutdowns to be performed, as the Company must open breakers (40 kV or 24 kV) to prevent post-contingency back feeding.

Therefore, the DTE system must be set up for load rejections prior to starting ITC shutdown, as such requiring DTE to install reverse relay schemes at various locations.

There was no activity in 2023. For 2024, the Company projected \$150,000 and spent approximately \$17,000. In 2025, as of the end of May, spending totaled roughly \$6,000 against a \$1,000,000 projection. The Company also projects \$1,000,000 for 2026.

Staff agrees the program is necessary, but the record shows materially lagging execution relative to projections. A reasonable adjustment is warranted pending evidence of ramp-up capability and committed work packages.

The Staff's recommended disallowances are \$200,000 for 2025 and \$200,000 for 2026.

The Company's witness rebuttal claimed that "The Company agrees that execution on the 'Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program' has been delayed in 2025, but full execution of the 2026 program is expected." (2 TR 199.) Since there is no updated information to lead Staff to believe this statement, Staff maintains the disallowance outlined in its revised direct testimony.

**xii. CODI: Garfield Network Upgrade (A-12 Schedule B5.4, page 11 line77,78,79,80): Part of IRM (Appendix E, Line 28)**

As Company witness Stowe stated in Exhibit A-23, Schedule M6, page 254, the Garfield project is part of the CODI plan that will address the load demand and aging infrastructure. Company witness Stowe also explained that:

The Company will complete additional design work for overhead circuit pre-conversion and underground conduit and cable, will construct underground conduit and cable, replace equipment on primary services to customers, and construct overhead circuit rebuilds as part of pre-conversion in 2026. [S-10.1, STDE-6.24.a.]

and

the Company will complete additional design work for overhead circuit pre-conversion and underground conduit and cable, construct underground conduit and cable, replace equipment on primary services to customers, and construct overhead circuit rebuilds as part of pre-conversion in 2026. [S-10.1, STDE-6.25a]

For Line 80, Garfield UG Radial Conversion, the Company will complete detailed engineering in 2026.

Garfield substation is to be decommissioned, and its circuits converted to the nearby 13.2 kV substation.

Per Exhibit A-23, Schedule M6, page 258, work started in 2020 and will finish in 2030. The Company installed network system cable in 2023 and will perform energization and conversion of the network as well as decommissioning of the network from 2024 to 2026.

DTE spent \$23,638,000 in 2023, \$19,291,229 in 2024 and projected \$14,450,000 for 2025 as well as \$33,808,612 for 2026.

The 2026 work appears similar in type to prior years but with a sharply higher request and without a comprehensive plan detailing how the full amount would be spent. Staff uses the 2023–2025 average (\$19,126,743) with a 2.66% inflation factor to forecast \$19,635,514 for 2026. The excess amount of \$14,173,096 (\$33,808,612 - \$19,635,514) is recommended to be disallowed for the test year.

**xiii. CODI: Howard Conversion (A-12 Schedule B5.4, page 11 line 82), part of IRM (Appendix E, Line 31)**

The Howard Conversion is also part of the CODI which addresses the load demand and aging infrastructure. Howard substation was commissioned in 1930 and has a higher risk of failure due to the aging equipment.

The construction scope of work within Howard Conversion includes AC Network Conversion, decommissioning an underground power line as well as converting customers to 13.2 kV.

For the test year 2026, the Company projects \$20,214,222. The record also describes a timeline starting in 2022 with equipment purchases in 2024 and construction/cut-over activities spanning 2025–2028 (A-23, M6, p. 262).

Despite the stated timeline, there is little evidence of earlier phase execution prior to the current case, and the filing does not include a comprehensive plan sufficient to support the entire 2026 request. Staff recommends a measured adjustment of \$4,042,844 (20%) from the 2026 projection as appropriate unless the Company provides detailed engineering packages, procurement status, a list of long-lead materials, a description of construction sequencing, and a customer conversion plan aligned with outage constraints.

**xiv. 4.8 kV CC: ISO Conversion Program (A-12 Schedule B5.4, page 11 line 83), part of IRM (Appendix E, Line 26)**

The Company developed the 4.8 kV Conversion Program which includes the 4.8 kV Conversion Program and 4.8 kV ISO Conversion Program.

As Company witness Stowe explained in his direct testimony:

In some areas, the Company operates portions of circuits at 4.8kV that are fed from a 13.2kV substation, using a transformer to reduce the higher substation voltage to the lower circuit voltage. These types of circuits are referred to as “isolation down” or “ISO down” circuits. This grid configuration exists where in the past there was a need to address immediate overloading on circuits fed from a substation at which other circuits were not overloaded. [2 TR 74.]

Recorded expenditures were approximately \$4,435,000 in 2023 and \$4,294,000 in 2024. Projections are \$5,256,000 for 2025 and \$18,030,000 for the 2026 test year.

According to A-23, Schedule M6, page 266, the Company is planning to do engineering and design from 2024 and beyond. With that being said, the work from 2024 and beyond should be similar from one year to another.

The Company describes similar types of engineering and construction work from 2024 onward. Given this, a more than three-fold increase in 2026 is insufficiently supported. Therefore, for 2026, Staff escalated the 2025 projection using a 2.66% inflation factor and recommends \$5,395,810 for 2026 (2025 projection inflated by 2.66%). Staff recommends the Commission disallow the balance of \$12,634,190 (\$18,030,000 – \$5,395,810) absent a detailed workplan tying quantities, unit costs, and schedules to the test-year request.

**xv. 4.8 kV CC: New Baltimore (A-12, Schedule B5.4, page 11 line 84), part of IRM (Appendix E, Line 27)**

The New Baltimore project includes acquiring substation property, constructing a new substation, and decommissioning two overloaded substations (currently at approximately 8.9 MVA and 11.2 MVA). Overhead jumpering is not feasible because the surrounding circuits are already served from 13.2 kV substations.

The project encompasses property purchase, new substation construction, and conversion/decommissioning of two overloaded substations. The Company's filings indicate engineering/design activities in 2024–2026 and construction/conversion during 2025–2027.

In Case No. U-21534, the Company requested \$2,345,000 but did not spend those funds in 2024 (A-23, Schedule M2, p. 7) and spent zero in 2025 (A-23, Schedule M3, p. 7). The current case projects \$14,500,000 for 2026 with a similar

schedule yet provides limited detail demonstrating readiness to execute at that level in the test year.

Staff's recommendation is to disallow \$2,900,000 (20%) from the 2026 projection unless the Company provides executed or draft agreements, a detailed engineering package, and a resource-loaded schedule that supports test-year spend readiness.

**xvi. 4.8 kV CC: Belleville Substation and Circuit Conversion (Exhibit A-12 Schedule B5.4, page 11 line 85), part of IRM (Appendix E, Line 29)**

According to Company witness Stowe:

Belleville Substation has a 13.2kV side with one circuit and a 4.8kV side with 3 load carrying circuits and a throwover circuit. There is a separate project to decommission the 4.8kV switchgear and reconfigure the circuits into two load carrying circuits. Once that work is complete, work can begin for this project to decommission the 4.8kV side of Belleville substation and expand the 13.2kV side of the substation.

Belleville Substation is at more than full load for its 4.8 kV side with 3 load carrying circuits and a throwover circuit, as well as the 13.2 kV side being at 91% of its firm rating. Staff agrees with decommissioning the overloaded 4.8 kV side and expanding the 13.2 kV side.

Although Exhibit A-23, Schedule M6 indicates conceptual engineering in 2024 followed by design and construction from 2025–2027; the record shows no completed activities to date. The Company should explain the delays and provide a comprehensive test-year plan.

Staff recommends the Commission disallow \$1,602,400 (20% of \$8,017,375) and requests for DTE to provide a detailed scope, milestone schedule, and cost breakdown for engineering, procurement, and construction activities.

**xvii. 4.8 kV CC: Ann Arbor AC Network Conversion (A-12 Schedule B5.4, page 11 line 88), part of IRM. (Appendix E, Line 32)**

The purpose of this project is to replace AC Network pedestals and Netbank transformers plus upgrade Hoover Substation from 4.8 kV to 13.2 kV. Netbank column inspection was conducted in 2019 and the inspection found many in need of repairing. To convert the AC Network, all columns will be replaced due to the lack of support for the further transformer units.

The Company spent approximately \$2,000 in 2023 (with no projection) and \$461,000 in 2024 (despite zero projection). Projections are \$3,300,000 for 2025 and \$5,067,000 for 2026.

Staff supports the conversion but observes limited planning detail in the record relative to the requested ramp-up. Staff requests clear delineation of engineering, overhead design and construction, and underground design and construction by year.

At this moment, Staff recommends disallowing \$660,000 (20%) from 2025 and \$1,013,400 (20%) from 2026 unless the Company files a work package plan that ties quantities and unit costs to the requested funding by functional category.

**xviii. 4.8 kV CC: Grosse Pointe Substation and  
Circuit Conversion (A-12 Schedule B5.4, page  
11 line 89) (Appendix E, Line 33)**

This project is part of the Grosse Pointe Area plan aimed at minimizing energized downed-wire risk and replacing aged infrastructure (weighted average age exceeding 70 years). The Company reports property acquisition in 2024 totaling approximately \$2,941,000, with engineering, pre-conversion, and conversion activities planned from 2024 through 2029.

The filing lacks a breakdown differentiating engineering, pre-conversion, and conversion activities as well as a definition of what is included in 'conversion.' Given the magnitude of the test-year request, more granular planning detail is needed.

Therefore, Staff recommends disallowing \$683,769 (20%) from the \$3,418,844 2026 projection unless the Company provides a fully itemized test-year plan and milestones with resource loading.

In his rebuttal testimony, Company witness Stowe stated that he had provided an appropriate level of detail in Exhibit A-50, Schedule QQ3, noting:

The Company will conduct detailed substation design, procure material, conduct overhead circuit rebuild detailed design for pre-conversion, and begin construction on overhead circuit rebuilds for pre-conversion in 2026. Additional details regarding the Grosse Pointe Substation and Circuit Conversion project can be found in Exhibit A-23, Schedule M6, on pages 287–290. [2 TR 200.]

However, Staff observes that the Company has not provided sufficient monetary detail to support these activities. Specifically, the rebuttal does not identify the respective costs associated with detailed substation design, material

procurement, or overhead circuit rebuild design, nor does it provide a clear schedule or duration for these activities.

Due to the continued lack of cost breakdowns and implementation details, Staff maintains the same disallowance as stated in its revised direct testimony.

**xix. 4.8 kV CC: Hemlock Decommissioning and Circuit Conversion (A-12 Schedule B5.4, page 11, line 90), part of IRM (Appendix E, Line 30)**

Hemlock (HEMLK) is a 4.8kV substation that is at 99% of its firm rating. The Ann Arbor area has a high percentage of electric vehicle adoption and has a goal of carbon neutrality and the elimination of natural gas heating. This project will help relieve existing overload conditions at this substation and provide additional capacity for existing and new customer load, according to Stowe. (2 TR 64.)

The Company projected \$152,000 for 2023 but spent approximately \$1,000; projected \$750,000 for 2024 but spent about \$208,000. Spending in the first five months of 2025 was reported as zero.

Given historical under-execution relative to projections and limited clarity regarding near-term deliverables, Staff recommends a measured adjustment to the 2025 and 2026 requests.

Staff recommends the Commission disallow \$300,000 (20%) from the 2025 projection (\$1,500,000) and \$239,000 (20%) from the 2026 projection (\$1,195,000) due to absence of a detailed scope of work, procurement status, and schedule for both years.

**xx. System Loading: Grenada (A-12 Schedule B5.4, page 11, line 108) (Appendix E, Line 30) (Appendix E, Line 30)**

Grenada substation is in Ann Arbor, where there are four substations serving the general area: Grenada, Price, Prospect and Wolverine. Prospect and Wolverine substations are either near or exceed 100% of firm rating. Several circuits on these four substations exceed the distribution design. The Company proposes engineering and construction work to relieve loading and align capacities with demand growth.

The Company projected \$3,521,000 and spent \$2,853,000 in 2023; projected \$6,535,000 and spent \$3,280,000 in 2024. DTE planned to do engineering and initial design from 2022 – 2024 and engineering, design for substation construction, and underground and overhead construction from 2025 to 2027. DTE projected \$12,000,000 for 2025; however, only \$1,069,000 was spent in the first five months of 2025. The Company's test year projection is \$8,867,000.

Staff supports the upgrades but notes a trend of underspending relative to projections. For 2025, Staff annualizes the 5-month spend (\$1,069,000) to \$2,565,600 and recommends disallowance of the balance of \$10,266,233.

For 2026, Staff inflates the annualized 2025 amount by 2.66% and recommends disallowance of the remainder of \$6,233,274 (\$8,867,000 - \$2,565,000 X 1.027).

The Company's witness Stowe stated that:

The local township permitting has resulted in the completion of additional design to the project which has delayed investment in 2025. The Company agrees that execution has been delayed in 2025, but full execution of the 2026 scope of work is expected to be completed in that year. (2 TR 201.)

Again, there are no details of how to execute the full scope of work for 2026, and the Company agreed the projects had been delayed in 2025. Staff needs the Company to provide the updated spending for 2025. Without this, Staff will keep the same disallowance as in revised testimony.

The following table is the summary of Staff's final recommendations for disallowances.

# in Brief	# in Testimony	Program/Description	Disallowance for 2025	Disallowance for 2026	Brief Disallowed 2025	Brief Disallowed 2026
c. i.	1	CVR/VVO		\$ 7,122,860		\$ 7,122,860
c. ii.	2	Distribution Automation (part of IRM)	\$ 83,077,000	\$ 92,477,223	\$ 62,253,571	\$ 71,099,891
c. iii.	3	Distribution Sensing and Monitoring (inclg Line Sensors)	\$ 2,600,243	\$ 845,623	\$ 2,600,243	\$ 845,623
c. v.	4	Distribution SCADA Historian		\$ 2,500,000		\$ 2,500,000
c. vi.	5	Mobile Equipment Replacement		\$ 1,750,000		\$ 1,750,000
c. vii.	6	Mobile Timesheets		\$ 700,000		\$ -
c. viii.	7	Vegetation Management Replatform		\$ 1,600,000		\$ -
d. i.	8	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	\$ 4,563,028	\$ 3,011,502	\$ 4,563,028	\$ 3,011,502
d. ii.	9	Subtransmission Redesign & Rebuild: Trunk 3509	\$ 1,501,600		\$ 1,501,600	
d. iii.	10	CODI: Alfred Substation Expansion	\$ 2,248,800	\$ 359,018	\$ 2,248,800	\$ 359,018
d. iv.	11	CODI: Targeted Network Secondary Cable Replacement	\$ 1,232,959	\$ 102,303	\$ 1,232,959	\$ 102,303
d. v.	12	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade		\$ 19,866,548		
d. vi.	13	4.8 kV CC: Calla Circuit Conversion and Phase 2		\$ 885,000		
d. vii.	14	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion - North		\$ 300,000		\$ 300,000
d. viii.	15	4.8 kV CC: Melvindale		\$ 360,000		\$ 360,000
d. ix.	16	System Loading: Jewell		\$ 400,000		\$ -
d. x.	17	Subtransmission Redesign & Rebuild: Trunk 7105		\$ 200,000		\$ 200,000
d. xi.	18	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	\$ 200,000	\$ 200,000	\$ 200,000	\$ 200,000
d. xii.	19	CODI: Garfield Network Upgrade		\$ 14,173,098		
d. xiii.	20	CODI: Howard Conversion		\$ 4,042,844		
d. xiv.	21	4.8 kV CC: ISO Conversion Program		\$ 12,634,365		
d. xv.	22	4.8 kV CC: New Baltimore		\$ 2,900,000		
d. xvi.	23	4.8 kV CC: Belleville Substation and Circuit Conversion		\$ 1,602,400		
d. xvii.	24	4.8 kV CC: Ann Arbor AC Network Conversion	\$ 660,000	\$ 1,013,351		
d. xviii.	25	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion		\$ 683,769		\$ 683,769
d. xix.	26	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	\$ 300,000	\$ 239,000		
d. xx.	27	System Loading: Grenada	\$ 10,266,233	\$ 6,233,274	\$ 10,266,233	\$ 6,233,274
		<b>Total</b>	<b>\$ 106,649,863</b>	<b>\$ 176,202,178</b>	<b>\$ 84,866,434</b>	<b>\$ 94,768,240</b>

Finally, Staff would recommend the Commission direct the Company to explain programs and associated expenditures in the exact order used in its tables

and exhibits. Aligning the order and labels across narratives, tables, and exhibits will significantly ease review and reduce misinterpretation.

**3. The Commission should exclude \$508 thousand from DTE's projected demand side management capital expenditures.**

Staff recommends disallowance of \$508 thousand of the Company's demand side management capital expenditures, which reduces rate base by \$349 thousand. (Appendix E, Line 50.) The specific exclusions are discussed in the following.

**a. Capital spending associated with demand side management—other demand response programs and pilots—C&I battery pilot should be reduced by \$508 thousand. (Appendix E, Line 49.)**

Staff recommend capital expenditures for demand side management – other demand response programs and pilots – C&I battery pilot should be reduced by \$508 thousand, which reduces rate base by \$349 thousand. (Appendix E, Line 49.)

**The Commission and ALJ should adopt Staff's recommendation to disallow \$508,000 associated with the second battery in the proposed C&I battery pilot.**

[References in the Record: Staff witness Matthews, 5TR 5078-5086; Company witness Leuker, 3 TR 1353-1356, 1381-1384; MEIBC<sup>5</sup> witness Sherman 5 TR 4030-4041.]

Staff witness Cody S. Matthews summarized Staff's position regarding the C&I battery pilot. Staff recommends disallowance of all costs associated with the second battery of the two-battery pilot. (5 TR 5058). Additionally, Staff recommends

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<sup>5</sup> Michigan Energy Innovation Business Council is known as MEIBC.

that any alternative use cases the Company pursues for the second battery should be dissimilar to the many other battery use cases the Company is currently exploring through its non-wires alternatives pilot. (5 TR 5086)

In its filing, the Company requests recovery of costs associated with the use of the second battery and additionally proposes using the second battery on its own site as a part of a non-wires alternative (NWA) project. (3 TR 1355). Witness Matthews notes that while using a storage device in conjunction with NWA projects can provide benefits, the Company already has several battery-based NWA projects and should ensure the uniqueness of its use case in the event that this second battery is diverted from the C&I pilot for use in another project. (5 TR 5084-5085)

In rebuttal, Company witness Leuker asserts that Staff's disallowance appears to be based on the misunderstanding that the battery will be used for NWA purposes. (3 TR 1382). While the Company is correct that Staff compares the use of the second battery to the use cases of DTE's other battery NWA pilots, the Company is incorrect in its notion that the proposed NWA usage is the reason for Staff's recommended disallowance. As noted in Staff's direct testimony, Staff believes that there could be value in using the second battery on site or for use as a non-wires alternative. (5 TR 5084-5085.) Staff's recommended disallowance is because the Company does not have a second customer and has not made a specific proposal about how the battery will be used. The Company's testimony simply lays out the use on a DTE site as an option, stating that the DR team is currently in the exploration phase of this option. (3 TR 1355.) Therefore, Staff stands by its

recommended disallowance as it appears that the Company has yet to propose a firm plan either for a second customer to participate in the pilot or for an acceptable alternative use for the battery.

MIEIBC witness Dr. Laura Sherman describes MIEIBC's recommendations concerning the C&I battery pilot recommending disallowance of the costs associated with the second battery and rejection of the pilot's current configuration. (5 TR 4041.) Witness Sherman additionally states that deploying the second battery through an internal business unit will not allow the Company to achieve the objectives. (5 TR 4033.) Staff agrees with MIEIBC witness Sherman's evaluation that the spending for the second battery should not be approved at this time, and that under the current pilot structure using the battery on site would not meet the objectives set out by the Company in its business case for this pilot. Staff however does believe that under a different business case the second battery may be useful, but since the Company has not provided that business case at this time, Staff stands by its recommendation to disallow the costs associated with the second battery. Staff encourages the Company to develop a business case to properly utilize the battery.

**4. Staff recommends reducing information technology capital expenditures by \$79.676 million.**

Staff recommends reducing information technology (IT) capital expenditures by \$79.676 million, which reduces rate base by \$46.806 million. (Appendix E, Line

79.) This is composed of six categories of adjustments discussed below at sections a-f below.

**a. Category one: Capital spending associated with IT—general estimate reductions should be reduced by \$40.633 million. (Appendix E, Lines 53-55.)**

Staff recommend capital expenditures for IT – general estimate reductions should be reduced by \$40.633 million, which reduces rate base by \$23.899 million. (Appendix E, Line 53-55.) This is composed of three adjustment described below.

**i. Level 2 cost estimates. (Appendix E, Line 53.)**

**[References in the Record:** Staff witness Danielle R. Rogers 5 TR 5049; S-12.2; Staff S-12.6; Company witness Steven B. Ambrose 4 TR 2125; Company witness Steven B. Ambrose, 4 TR 2127; Company witness Steven B. Ambrose 4 TR 233.1]

Staff recommends that the ALJ and the Commission disallow 20% of the costs associated with IT projects with Level 2 cost estimates. This disallowance includes 5 of the 8 projects with a Level 2 cost estimate and \$0.685 million in capital expenditures in 2026. (5 TR 5052.)

Level 2 cost estimates are immature and imprecise. A Level 2 cost estimate is given to a project more than a year, or sometimes more than two years, before execution. It is likely that changes impacting the cost will occur during implementation, such as changes in the scope or timeline of the project, a project's priority within the Company's Annual Planning Cycle, or the necessity of the project altogether. (5 TR 5052). Company witness Ambrose rebuts Staff's testimony, arguing that projects with Level 2 cost estimates are comprehensive by

cost type and project phase. He states they are developed with input and review by IT subject matter experts based on scope, historical data, and vendor quotes, and that the subject matter experts have firsthand knowledge of the Company's IT infrastructure and needs and have learned lessons from past projects. Company witness Ambrose adds that Level 2 estimates support project funding and prioritization decisions, and changes to project costs that occur after a Level 2 estimate is given are because of legitimate adjustments in project scope or requirements identified after the estimate is established. Essentially, the Company's claim is that these changes do not reflect a flaw or deficiency in the initial estimate. (4 TR 2332-2333.)

However, Staff maintains its position. Regardless of who is developing the estimates and how much experience they have, the purpose of Level 2 cost estimates, as stated in rebuttal testimony, is project funding and prioritization decisions. Testimony shows changes have occurred for 50 of the projects the Company is currently seeking recovery of, for at least one of these reasons. (5 TR 5052-5053.) Staff recognizes changes are a natural consequence of project design, especially given the fast-paced nature of technology, however they occur because the project plan is immature and the cost estimate is uncertain, so far ahead of execution. It is the responsibility of the Company, and in the best interest of ratepayers, to only include the most accurate project costs in rates. It is unreasonable to pass the full Level 2 investment expense, which is still vulnerable to important changes, onto ratepayers. If the full amount is not spent, the

Commission is unable to perform retroactive ratemaking to reimburse customers. If the Company spends more than 80% of the requested cost, it can always seek recovery in its next rate case application.

Next, Company witness Ambrose rebuts the use of the Association for the Advancement of Cost Engineering (AACE) Cost Estimate Classification System 18R-97 for establishing an adjustment because it applies to engineering, procurement, and construction activities for process industries and not IT project cost estimation. (4 TR 2333.) However, Staff did not use the 18R-97. Staff used the 17R-97, which is a methodology for estimating project costs across all industries. Staff believes Level 2 cost estimates align closest with a Class 3 estimate. The purpose of both estimates is budget authorization. (5 TR 5054-5055.)

Lastly, Company witness Ambrose argues that taking a position in a case because that same position was taken in a previous case is not sufficient justification and Staff's blanket disallowance disregards evidence of record in this case. (4 TR 2333.) Staff disagrees with this assertion. Staff's testimony and evaluation of Level 2 cost estimates proves that Level 2 cost estimates are imprecise. When comparing Level 2 cost estimates with actual costs, the Company over recovered on 94 of the 147, or 64%, of the investments with an average over recovery of 40.31%. Alternatively, the Company under recovered on 53 of the 147, or 36%, of the investments with an average under recovery of 66.38%. The percent change in Level 2 cost estimates to actual costs range from 109.01% over recovery to 742.86% under recovery. (5 TR 5053.) This range is well beyond the Company's

stated Level 2 cost estimate accuracy range of -15%/+20%. (S-12.2, p 1.) Given this analysis, 20% is a conservative recommended disallowance.

For these reasons, the ALJ and the Commission should disallow 20% of the requested expenses for the IT projects with a Level 2 cost estimate. This totals to a capital expenditure disallowance of \$0.685 million in 2026.

**ii. Level 3 cost estimates. (Appendix E, Line 54.)**

**[References in the Record:** Staff witness Danielle R. Rogers 5TR 5049 –5051 ; Staff witness Danielle R. Rogers 5TR 5056 –5059 ; S-12.2; S-12.7; S-12.8; Company witness Steven B. Ambrose 4TR 2125, 2128; 2334–2337; A-44 JJ2 (rebuttal).]

Staff recommends that the ALJ and the Commission disallow 10% of the costs associated with projects with Level 3 cost estimates. This results in a capital expenditure disallowance of \$13.077 million in the 2025 bridge period and \$11.367 million in the 2026 test year. (5 TR 5056.)

Level 3 cost estimates are inaccurate in nature. (5 TR 5057.) However, in his rebuttal testimony, Company witness Ambrose disagrees with Staff, arguing that Level 3 cost estimates are accurate and cost updates due to scope changes during implementation are a widely accepted project management practice. He further states that the variances between Level 3 cost estimates and actual costs are not due to estimation error but are a result of mature estimating practices. (4 TR 2335.)

Yet, Staff maintains its position because Level 3 cost estimates are subject to change and passing their full costs onto ratepayers would be premature. As stated by the Company “Level 3 estimates are accurate and comprehensive **at their point**

**of development, supporting project requirements and initial budget decisions.”** (4 TR 2335 (emphasis added).) Staff is not disputing that Level 3 cost estimates are not appropriate for initial budget decisions internal to the Company, at their point of development. Project estimates may be complete for the stage in which the Level 3 cost estimate is given, however in the overall process of project development to implementation, they are incomplete. As admitted by the Company, scope changes occur during implementation. While that may be a “widely accepted project management practice” or “mature estimating practice,” it is inappropriate for ratemaking purposes.

Through audit, the Company provided a spreadsheet of projects with their Level 3 cost estimate from the previous electric rate case, Case No. U-21534, and their actual cost in the instant case. Staff calculated the percent change of the project’s costs and found that DTE over recovered on 77 of the 159 projects, or 48%, with an average over recovery of 34%. DTE under recovered on 73 of the 159 projects, with an average under recovery of 45%. Nine of the 159 projects had no cost change. The percentage change ranged from 108.99% over recovery to 730.84% under recovery. (5 TR 5057.) These statistics are significantly outside the Company’s stated Level 3 cost estimate accuracy range of -10%/+15%. (S-12.2)

In rebuttal testimony, Company witness Ambrose disagrees with Staff’s analysis of costs stating it is “incomplete, unstructured, and does not represent a widely accepted practice for calculating estimate to actuals variances for a project.” (4 TR 2335.) He argues that cost estimates should be evaluated over the full project

lifecycle, not by year, because judging accuracy on annual spend can cause misleading conclusions. He states that if historical spend comparisons are used, planned and actual expenditures across the whole period should be used, such as assessing spend over the combined 2023 and 2024 years. (4 TR 2335.) The Company provided its analysis by filing Rebuttal Exhibit A-44 JJ2 Level-3 Over Recovery Analysis. This spreadsheet evaluates the performance of the 77 projects over recovered on over a combined period of 2023 and 2024. Removing 14 projects linked to multi-year projects, 63 unique projects remain. Of those 63 projects, the Company states that 26 projects were within the +/- 10% range, 6 projects show under recovery greater than 10%, and 31 projects show over recovery greater than 10%. The Company states that over recovery occurred for the 31 projects in this exhibit, not because of poor estimation practices, but because of scope changes, efficiency gains and cost savings, or schedule changes. The Company states 6 of the projects were due to a true variance. (4 TR 2336.)

Staff does not find the Company's analysis reassuring. First, the Company's analysis is incomplete. The Company only evaluated 77 of the 159 projects using this combined 2023-2024 year methodology. The 73 under recovered projects may be subject to changes as well, with some possibly being over recovered on. Second, this limited analysis already shows that the Company over recovered on 46 of 136, or 34%, of the projects. This percentage is likely to grow with the evaluation of the under recovered projects. Additionally, there are 3 projects that were greatly over recovered on, but the Company listed no variance because the projects were merged

with CR&B. Regardless of if the projects were merged, the costs were still approved for recovery in Case No. U-21534 and were not completely spent in the instant case. Lastly, irrespective of the reasons the Company listed for over recovery, these are costs passed on to ratepayers that were not fully used for their intended purpose. This is unfair to customers. The Company chooses to file a projected test year in its rate case application and is responsible for ensuring accurate expenses are passed onto ratepayers. If the full cost of the project is not needed, the Company can earn a return off and a return on expenditures that were spent imprudently or were not incurred for what they were projected. The Commission has no way of correcting this issue.

Staff chose a recommendation of 10% for Level 3 cost estimates because that is the lower bound of the accuracy range that the Company states Level 3 cost estimates have. If the Company spends more than 90% of the projected costs on an investment. They can seek recovery in the next electric rate case by providing evidence of reasonable and prudent spending.

For the reasons discussed above, Staff recommends the Commission disallow 10% of costs related to projects with Level 3 cost estimates. This includes a capital disallowance of \$13.077 million in the 2025 bridge period and \$11.367 million in the 2026 test year.

- iii. The ALJ and the Commission should reduce the shared asset revenue if Staff's recommended disallowances for IT projects that are shared assets are accepted.**

**[References in the Record:** Company witness Theresa M. Uzenski 4TR 2446-2448.]

Company witness Uzenski filed Rebuttal Exhibit A-37, 15 Schedule BB1, column (f) showing the reduction to the shared asset revenue for each project Staff recommended a disallowance for. (Uzenski, 4TR 2494.) Staff agrees. If the ALJ and the Commission approve the recommended IT project disallowances made by Staff, they should also reduce the shared asset revenue.

**iv. Overhead reduction (Appendix E, Line 55.)**

**[References in the Record:** Staff witness Danielle R. Rogers, 5 TR 5059–5062; S-12.9; S-12.10; Company witness Steven B. Ambrose 4TR 2338; A-24 Schedule N3 Column X; Company witness Theresa M. Uzenski, 4 TR 2499]

The ALJ and the Commission should disallow 100% of the “Projected Capital Overhead and Other Costs (Capital)” for all projects with spend not already approved in Case Number U-21534. This includes \$0.731 million in the 2023 historical year, \$3.231 million in the bridge period (\$0.284 million in 2024 and \$2.947 million in 2025), and \$11.542 million in the 2026 test year. (5 TR 5060.) Staff notes that to avoid duplication with Staff’s other IT investment recommendations, only projects with an actual cost, projects with a Level 3 cost estimate whose projected overhead costs are greater than 10%, and projects with a Level 2 cost estimate whose projected overhead costs are greater than 20% are included. Projects in which Staff has an alternate recommended disallowance are also not included.

Staff does not believe the Company has adequately justified the projected capital overhead expenses. Staff sent numerous audit requests to the Company to understand what the projected overhead expenses are used for and how they are determined. The Company responded with a general list of possible uses for the costs, however was unable to specify which uses applied to which projects or what the costs were. (5 TR 5060.)

Company witness Uzenski rebuts Staff's recommendation, stating that overhead costs are recurring, indirect, and routinely given to all capital projects implemented by the Company (4 TR 2499.) DTE further states that overhead costs are "accumulated in total and then allocated to capital projects, generally by applying an overhead rate to construction charges such as direct labor or materials." (Uzenski, 4 TR 2500.) Staff disputes this explanation. By Staff's calculations, the overhead costs are arbitrary. There is no allocation pattern or method to their application to projects. Some IT projects with projected capital costs and capital labor costs do not have overhead costs. Some IT projects with projected capital costs and capital labor costs do have overhead costs. The percentage of projected overhead costs to total capital cost differs for each project. For example, the Fuel Supply Application Health project has overhead costs that are 38% of the total capital cost, while the IT Service Management Tool project has overhead costs that are 3% of the capital cost. Even projects that are the same but have capital spent in different years, such as the Everyday Daily Plan Application Health project, have different percentages of overhead costs to the total projected

capital costs. (S-12.10) To verify the Company's assertion that overhead costs are determined by an allocation rate to construction charges, Staff also calculated the percentage of overhead costs to the capital labor costs. These percentages also differed. Company witness Uzenski argues Staff's discovery response that overhead costs cannot be traced to a project, but that Staff still expects specific cost information for individual IT projects, is contradictory. (4 TR 2501.) Staff asserts that each individual IT project has a specific and different overhead cost. The Company has the responsibility to demonstrate how that cost was determined to prove reasonableness and prudence.

Staff understands that overhead costs are indirect and are not a material component of the IT investment. Staff also agrees that overhead costs are appropriate for capitalization. However, all costs should be justified, reasonable, and prudent to be passed onto ratepayers. Without knowledge of how overhead costs are determined, they are unable to be deemed justified, reasonable, or prudent.

Company witness Uzenski's statement that overhead costs are allocated "generally by applying an overhead rate to construction charges such as direct labor or materials" sounds ambiguous, (4 TR 2500.) like the allocation is uncertain and there is not an exact methodology. The Company assigns each IT investment overhead costs. That overhead cost varies for each project. With differing overhead costs for each project, the Company must have knowledge of, and should have record of, which possible use applies to each project and/or the allocation of costs

and methodology for each project. If that information is unknown, Staff does not understand how the overhead costs can be accurately projected. Staff has found no correlation between any cost component of an IT investment and the projected overhead. The Company has been unable to provide Staff with an explanation of how the overhead costs are determined. Without this information, these costs are arbitrary and groundless.

For these reasons, the ALJ and the Commission should disallow 100% of the “Projected Capital Overhead and Other Costs (Capital)” for all projects with spend not already approved in Case Number U-21534. This includes \$0.731 million in the 2023 historical year, \$3.231 million in the bridge period (\$0.284 million in 2024 and \$2.947 million in 2025), and \$11.542 million in the 2026 test year.

**b. Category two: Capital spending associated with IT—customer IT should be reduced by \$31.635 million. (Appendix E, Lines 57-63.)**

Staff recommend capital expenditures for IT – customer IT should be reduced by \$31.635 million, which reduces rate base by \$18.785 million. (Appendix E, Line 57-63.) This is composed of six adjustments described below, as described by Staff witness Brittney Klocke. (See section iv. below for a combined adjustment.)

**i. Customer Insight Platform Application Health (Appendix E, Line 58.)**

[References in the Record: Klocke 5 TR 5114-5116, S-12.1, S-17.1, S-17.3, S-17.4.]; Ambrose 4 TR 2265-2266, 2329, 2357-2363, A-12, Schedule B5.7.2, A-24, Schedule N3.]

In direct testimony, Staff witness Brittney Klocke recommended full disallowance of the requested costs for the Customer Insight Platform Application Health project for the test year ending December 31, 2026 in the amount of \$4.275 million in capital expenditures. (5 TR 5114-5116.) The Commission and ALJ should disallow the requested costs for the Customer Insight Platform because the project has low customer usage and the Company has not been able to demonstrate strong customer support for the project. (*Id.*)

The Customer Insight App is a renaming of the Powerley Customer Platform Application health project, which included the DTE Mobile Insight Application Health, Energy Bridges, Bill Management, and the Powerley Portal, recovery of which was disallowed by the Commission in MPSC Case No. U-21297, 12/01/23 Order. (Klocke, 5 TR 5114-5115.) In Case No. U-21534 the Company used increased customer participation in the DTE Insight Program and usage of the Energy Bridge devices as justification for recovery of requested expenses. (*Id.* at 5115.) In that case, the Company sought and received over \$4 million and stated that the number of DTE Insight App and Energy Bridge users would continue to increase. (*Id.*) However, in the instant case the usage rate for the Customer Insight App has been revealed to be just 2.17% of the Company's total electric customer base, an extremely low number for a program that the Company began investing in in 2014. (*Id.*) The Company indicates that downloads of the Customer Insight App have increased from 2023 to 2025, yet downloads do not equal usage and the actual usage of the Insight App remains very low. (4 TR 2358.)

In addition, Staff asserts that the usage of the Energy Bridge devices has declined, with just 29,000 current users having an authenticated Energy Bridge device as opposed to 38,093 by the end of 2022 and 56,519 by the end of 2023. (5 TR 5116.) The Company has been unable to account for the decline in the Energy Bridge devices by over 27,000 customers in the past two years. (*Id.*) And as Staff witness Klocke stated in her direct testimony, the Commission in Case No. U-21297 agreed with Staff that the Company needed to demonstrate increased customer participation and usage with those programs in order to support recovery, and the Company has been unable to achieve that goal. (*Id.*)

In its rebuttal testimony, Company witness Ambrose discusses the benefits of one element of the Customer Insight App, the Bill Management tool. According to the Company, 55% of surveyed customers indicated that they were less likely to call the Contact Center after using the Bill Management tool. (4 TR 2360.) However, the Company never indicated how many customers were surveyed regarding this, and therefore the survey results mean very little when it is unknown how many customers were actually surveyed. (*Id.*) The Company also provided usage of the Bill Management tool, which has remained fairly static at an average of 221,000~ unique yearly users from 2022-present. (*Id.* at 2360-2361.) This is just under 10% of the Company's electric customer base. No purported savings for customers self-serving using the Bill Management tool were tied to this tool or the overall Customer Insight App.

Company witness Ambrose also discussed a new element that was piloted from February 1-August 1, 2025, the BillWise AI tool. This tool offers “AI-driven insights” into customers’ energy bills to help them understand billing changes and explore recommendations to reduce energy costs. (*Id.* at 2361.) However, just 49,000 customers used the BillWise AI during its six month pilot and no customer feedback regarding it was provided by the Company. (*Id.*) There are so many unknowns regarding the accuracy of AI-generated information and Staff is not convinced this AI tool will be an accurate and useful tool that customers will see real benefit from. The Company has provided very little information about this tool, how “intelligent” it will be, where it will aggregate the information from, and any future cost savings that will be realized by the tool. Staff sees very little real benefit for customers in this tool and its addition to the Customer Insight App is certainly not a reason to allow recovery for that greater project.

Since the Company has failed to demonstrate strong customer usage and support of the Customer Insight App and its various elements, Staff maintains that the recovery of the costs for the Customer Insight Platform Application Health project in this instant case be disallowed.

**ii. DTE Mobile App Application Health  
(Appendix E, Line 59.)**

**[References in the Record:** Company Ambrose, 4 TR 2270-2271, 2329, 2368-2370, A-24, Schedule N3, A-12, Schedule B5.7.2; Staff witness Klocke 5 TR 5119-5120, S-17.10.]

In her direct testimony, Staff witness Klocke recommended full disallowance of the requested costs for the DTE Mobile Application (Mobile App or App) for the

test year ending December 31, 2026 in the amount of \$1.100 million in capital expenditures. (5 TR 5119.) The Commission and ALJ should disallow the requested costs for the Mobile App because the App's usage remains quite low and the App itself offers nothing not already available to customers via the Company's website. (*Id.*)

As Staff witness Klocke noted in her direct testimony that the App accounts for just 19% of the Company's total self-service usage and allows customers to report outages, make payments, and access their bill. (5 TR 5119.) However, all these functions can also be done using the Company's website, which is also compatible with mobile devices. (*Id.*) Though the Company points out that between 42-50% of outage interactions are completed using the App, it does not acknowledge that outages can just as easily be reported using the Company's website. (4 TR 2270,2368.) In fact, as Company witness Ambrose himself stated in his rebuttal testimony, the App offers "limited functionality and interaction volume," along with the "same core functionality as the Website." (4 TR 2369.) Customers may indeed prefer to utilize different channels based on their convenience, but the App's overall low usage rate for the 14+ years it has been available means that no further recovery should be granted for it. In the past three years, the App's interactions have grown just 5%. (*Id.*)

Though the Company argues that the costs for the App in the instant case are necessary to keep the App available and functional for customers, it neglects to take into account the over \$6 million granted for the App in Case No. U-21297 to

rewrite, update, and maintain the App and improve its resiliency. (4 TR 2271, 5 TR 5120.) At this point, Staff does not see a compelling argument for allowing more recovery to be used primarily for maintenance and to achieve improved customer experience ratings for a project that does not have strong customer support or usage and offers limited functionality that is duplicative of the Company's website. (4 TR 2369.) There is no evidence that the App will not remain functional and secure for customers without the requested recovery in the instant case. And, since the Company has not proven that this requested spend is reasonable or prudent, all costs requested for the App should be disallowed.

**iii. Payment Merchant Fees (Appendix E, line 60.)**

**[References in the Record:** Ambrose 4 TR 2316-2321, 2330, 2379-2383, A-12, Schedule B5.7.2, A-24, Schedule N3; Klocke 5 TR 5126-5128, S-17.11, S-17.12.]

In direct testimony, Staff recommended full disallowance of the requested expenditures for the Payment Merchant Fees project in the amount of \$9.998 million in capital costs for the bridge period ending December 31, 2025. (5 TR 5126.) The Commission and ALJ should adopt Staff's recommendation and disallow the requested costs for this project because the Company has not proven that the requested costs are justified.

Staff requested a breakdown of the costs requested for this project during the analysis period and was merely directed to the generic program summary for an explanation of the costs. (5 TR 5127.) The Company provided no reasoning behind those costs given, nor was it ever explained why the contractor costs were over \$8

million. (*Id.*) In its rebuttal testimony, the Company explained that they have hired “long-standing business partners of the Company” for this project who have previously undergone vetting. (4 TR 2380.) However, no evidence was given that the contractors and their costs were strictly vetted for this project in particular. Just because the Company has a previous relationship with a contractor does not mean that that contractor is the best, most cost-efficient choice each time.

The Company did provide an estimate from the contractor in its rebuttal testimony, but Staff would argue that this information was received too late for an accurate analysis to be conducted. (4 TR 2381-2382.) Staff also questions why this information was not provided prior to Staff’s direct testimony being filed, when Staff explicitly asked for the contractor costs and reasoning behind them. (5 TR 5127.) At this point, the Company cannot prove that due diligence was done in selecting, vetting, and approving the contractor costs for this project, and therefore the requested costs for it should be disallowed.

**iv. Outage WISMO and Map Sustainment; Outage WISMO, PPS, and Map Enhancements (Appendix E, Lines 61-62.)**

**[References in the Record:** Ambrose 4 TR 2273-2274, 2302-2303, 2313-2315, 2329-2330, 2370-2379, A-24, Schedule N3; Klocke 5 TR 5120-5126, S-17.13, S-17.15, S-17.16.]

In her direct testimony, Staff witness Klocke recommended full disallowance of the requested costs for the Outage WISMO, PPS and Map Application Health project for the bridge year ending December 31, 2025 in the amount of \$3,000,000 in capital, as well as \$5,250,000 in capital expenditures. (5 TR 5120-5121.) Staff also

recommended full disallowance of the requested costs for the Outage WISMO, PPS and Map Enhancement projects for the test year ending December 31, 2026 in the amount of \$1,700,001 in capital expenditures. The Commission and ALJ should disallow the requested costs for these projects because, as part of the Error Free Communication Project, the requested costs for these projects are too premature to be granted at this time.

The requested expenditures for the Outage WISMO, PPS and Map Application Health and Outage WISMO, PPS and Map Enhancement projects are directly tied to the Company's larger Error Free Communication (EFC) project, for which over \$50 million in expenditures from Case Nos. U-21297 and U-21534 has already been granted. (5 TR 5121.) Staff did not make any monetary adjustments to the EFC project in Case No. U-21534 but did request that the Commission order the Company to meet regularly with Staff in the form of biannual meetings and to demonstrate the metrics and progress toward the stated goals of the EFC. (5-TR 5122.) The Commission adopted Staff's recommendations regarding the EFC in Case. No. U-21534 and ordered the Company to meet with Staff biannually to provide detailed status updates on continuous improvements, failures, and metrics of the EFC and its components. (5 TR 5123.) The history of the EFC is important to know as it directly ties to the requested expenditures in the instant case for the Outage WISMO, PPS, and Map Application Health and Outage WISMO, PPS, and Map Enhancements project for the current case.

The January 23, 2025 Order for Case No. U-21534 was issued just before the filing of this instant case, yet the Company is already asking for an additional \$10 million to be spent on elements of the EFC long before they have proven that the past approved expenditures for the EFC have been useful and the goals of the EFC have been met. (5 TR 5124.) As of today's date, the Company has met with Staff for just one biannual meeting regarding the progress of the EFC and many unknowns regarding the success of that project remain. It cannot be overstated how premature and unreasonable the requested costs are, and the Company has never shown why these costs are needed for these projects. (5 TR 5125.)

In its rebuttal testimony, Company witness Ambrose states that \$8.3 million of the requested \$10 million for the Outage WISMO, PPS and Map Application Health project is new and has not been requested in previous rate cases. (4 TR 2371.) However, funding for these elements were specifically called out in the Company's direct testimony in Case. No. U-21534. *See* MPSC Case U-21534, Hatsios, 6 TR 2252-2265. The Company further claims that the funding for Application Health projects is being requested now because the EFC systems have "reached a state of development through previously approved investments by which they can and must be sustained." (Ambrose, 4 TR 2371.) Staff has questions and serious reservations as to why, after being granted a substantial amount of money for the EFC program so recently, this money is already needed to sustain elements of the EFC; seemingly, the Company did not do its due diligence in estimating the costs for the EFC in previous rate cases if so much additional money is already

needed. Also, the Company claims that the Application Health expenditures for these projects will enable customer communications and outage management and without this funding, “performance will decline, leading to slower responses, inaccurate communications, and reduced customer trust.” (4 TR 2375.) However, nowhere does the Company explain how or why these things will happen and this appears to be an empty threat of what *could* happen rather than what will happen.

In addition, Company witness Ambrose is requesting money for the Outage WISMO, PPS and Map Enhancement project to “build and enhance the EFC systems.” (4 TR 2376.) What exactly needs to be built is unclear, as well as why these expenditures are necessary at this time. Moreover, nebulous statements made by the Company that claim this project will “enhance the customer experience” do not give Staff confidence that the requested expenditures are at all reasonable or prudent. (*Id.*)

In sum, the Company has yet to prove significant progress in its stated goals and metrics for the EFC project and therefore has not proven further recovery is prudent for any projects relating to it. The Company may indeed be making progress toward its stated goals and metrics for the EFC, but the Commission would be remiss in allowing additional recovery at this time. For all these reasons, along with those stated in Staff’s direct testimony, the requested expenditures for the Outage WISMO, PPS and Map Application Health and Outage WISMO, PPS and Map Enhancement projects should be disallowed.

v. **Customer Relationship and Billing Program  
(Appendix E, Line 63.)**

**[References in the Record:** Ambrose, 4 TR 2267-2268, 2329, 2363-2367, A-24, Schedules N1, N3; Klocke, 5 TR 5116-5119, S-17.6, S-17.7, S-17.8, S-17.9.]

In its direct testimony, Staff recommended full disallowance of the requested costs for the Customer Relationship and Billing Program (CR&B) for the test year ending December 31, 2026 in the amount of \$6.310 million in capital expenditures. (5 TR 5116-5118.) The Commission and ALJ should disallow the requested costs for the CR&B program because the program's costs are extremely high for an ongoing, fully implemented program and the Company has not demonstrated the necessity of the requested costs.

Despite being asked by Staff to provide a detailed response regarding the high costs requested for the CR&B program in this instant case, the Company only provided basic responses to Staff's questions. (Klocke 5 TR 5117.) Additionally, as testified by Staff witness Klocke, when Staff asked the Company how this project and its updates would benefit customers, Staff was directed back to the Company's exhibits that give basic project summaries. (*Id.* at 5117-5118.) The CR&B is a fully implemented program that requires maintenance costs at this point, so it is hard for Staff to understand why over \$9 million in capital and O&M expense combined is being requested for this program in the instant case. (*Id.*) In his rebuttal testimony, Company witness Ambrose pointed out ongoing maintenance activities that are to be funded and state that those activities "reduce the risk of unplanned outages within the CR&B platform that disrupt critical business operations and

lead to customer dissatisfaction.” (4 TR 2365.) Though the Company listed the various operational and product support activities provided by the CR&B, the Company has not provided information as to *why* the requested costs for this project are so high, nor have they proven that any outages will actually occur if recovery is not granted in this case. (4 TR 2365-2367.)

Staff has a responsibility to ensure that requested expenditures are both reasonable and prudent and nothing provided by the Company in relation to the requested costs for the CR&B program show reasonableness or prudence. Activities the Company names in its rebuttal testimony as reasons for the requested expenditures for this project such as supporting ongoing maintenance, yearly patching, and “minor enhancements” do not rise to the level to justify this amount of money. (*Id.*) For the reasons discussed here and in Staff’s direct testimony, the requested expenditures for the CR&B program should be disallowed.

**c. Category three: Capital spending associated with IT—plant & field should be reduced by \$3.952 million. (Appendix E, Lines 65-67.)**

Staff recommend capital expenditures for IT – plant & field should be reduced by \$3.952 million, which reduces rate base by \$2.161 million. (Appendix E, Line 65-67.) This is composed of two adjustments described below.

**i. The first adjustment is Maximo Engineering Process Automation (Appendix E, Line 67.)**

**[References in the Record:** Staff witness Danielle R. Rogers 5TR 5064–5066; S-12.11 p. 2; Company witness Steven B. Ambrose 4TR

2250; Company witness Steven B. Ambrose 4TR 2347–2349 Line 16; A-12 Schedule B5.7.4]

Staff recommends that the ALJ and the Commission disallow \$2.552 million (Appendix E, Line 67) in the 2024 bridge period for the Maximo Engineering Process Automation project. (5 TR 5064.) This investment will streamline engineering and work management systems at Fermi and reduce manual tasks, resulting in improved reporting and easing the management of multiple system interfaces. (4 TR 2250.)

Staff submits that the Maximo Engineering Process Automation project is an unnecessary and imprudent use of funds. DTE testimony claims that \$4.2 million more was spent in the 24 months ending December 31, 2024, than was approved in Case Number U-21534. This extra \$4.2 million consists of \$1.1 million because of Staff's Level 2 and 3 cost estimate adjustment, and \$3.1 million due to the scope of the Integrated Information Resource (I2R) Replacement being added to this project and to advance the timeline of the project from 2024 and 2025 to 2023 and 2024. In Case Number U-21534, the 2023 projected cost of the I2R project was \$0.595 million, leaving the remaining \$2.552 million for project acceleration. Company testimony stated that the purpose of reallocating the timeline of the project was not only expediting the project but also for cost savings. However, when asked through audit to provide the anticipated cost savings per year, DTE responded that "There are no quantifiable hard savings directly from implementation of this project." Further, it states that this investment sets a foundation for implementation of

future IT investments that are expected to provide greater operational and maintenance efficiencies in Fermi's sustainable staffing levels. (5 TR 5065- 5066.)

Company witness Ambrose rebuts Staff's recommendation, arguing the term "cost savings" was intended to mean reducing total project costs by combining the Maximo Engineering Process Automation project with the I2R project. He claims Staff's audit question was interpreted as operational cost savings or reductions in nuclear operations expenses, which was not DTE's purpose for moving the timeline of the project forward. (4 TR 2348 -2349.) As such, Company witness Ambrose provided no support for his argument that the term "cost savings" was intended to mean the reduction in total project costs by combining two projects.

Staff maintains its position that costs spent to move this project ahead one year were unnecessary and imprudent. Regardless of the Company's purpose for accelerating this project and the interpretation of the term "cost savings", DTE is unable to quantify any reduction in costs from this project and the advancement of its implementation. Spending \$2.552 million solely on moving a project timeline forward without any evidence of cost savings is unreasonable and unfair to pass on to ratepayers. Therefore, the ALJ and the Commission should disallow \$2.552 million for the Maximo Engineering Process Automation project.

**ii. The second adjustment is Corporate Instance -Maximo Application Suite Upgrade Phase 2 (Appendix E, Line 66.)**

**[References in the Record:** Staff witness Danielle R. Rogers 5TR 5062 –5064; S-12.11 pg 1; Company witness Steven B. Ambrose 4TR

2240–2241 ; Company witness Steven B. Ambrose 4TR 2344–2345; A-12 Schedule B5.7.4, Line 22.]

Staff recommends that the ALJ and the Commission disallow \$1.4 million in the 2026 test year for the Corporate Instance-Maximo Application Suite Upgrade investment. (5 TR 5063.) The Corporate Instance-Maximo Application Suite Upgrade supports the Work Asset Management functions at DTE. This investment involves the planning and design of the new version of Maximo, which will support and ensure resiliency for future needs. (4 TR 2240.)

Staff submits that the Company did not support \$1.4 million in the test year. In DTE’s previous electric rate case, Case Number U-21534, the Company projected a 2025 investment of \$3.749 million for the Corporate Instance-Maximo Application Suite Upgrade project. In the instant case, Company testimony reports a variance of \$3 million due to the deferral of the project into 2026. However, the Company’s request of \$8.160 million in the instant case calculates to more than a \$3 million variance, by an amount of \$1.4 million. (5 TR 5063- 5064.)

Company witness Ambrose opposes Staff’s recommendation. He states that Staff’s analysis does not take into consideration the projected 2026 spend, as it was not included in the scope of the Case Number U-21534 case period. (4 TR 2345.)

Staff maintains its position. In testimony, the Company did not support both 2025 and 2026 spend. In fact, testimony explains the 2025 investment in the instant case in a similar way it explains the 2025 investment in U-21534. In the last paragraph of testimony, DTE explains the \$3.0 million variance due to deferral

to 2026, however testimony contains no mention of additional scope from 2026 spend.

Therefore, the ALJ and the Commission should disallow \$1.4 million in the 2026 test year for the Corporate Instance-Maximo Application Suite Upgrade project.

However, if the ALJ and the Commission do not approve Staff's recommendation for a \$1.4 million disallowance in the 2026 test year, an alternative disallowance of \$0.816 million should be made consistent with Staff's recommended 10% adjustment for projects with a Level 3 cost estimate.

- d. Category four: Capital spending associated with IT—information protection security should be reduced by \$370 thousand and \$283,000 in O&M expenditures for the Communication Compliance and Data Loss Prevention (DLP) Diversification project. . (Appendix E, Lines 69-70.)**

**[References in the Record:** Staff witness Zichi, 5 TR 5133, 5135, S-18.0, pages 1-3, pp. 4-5, p. 6; Ambrose, 4 TR 2145-2146, 2356-2357.]

Staff recommends capital expenditures for IT – information protection security – communication compliance and data loss prevention (DLP) diversification should be reduced by \$370 thousand, which reduces rate base by \$232 thousand. (Appendix E, Line 70.)

In Staff's direct testimony, it recommended the Commission disallow \$186,000 in the projected bridge year ending 12/31/2025, in addition to \$184,000 in capital and \$283,000 in O&M expenses in the 12-month test year ending 12/31/2026. (5 TR 5133.) Staff recommended this disallowance because the

Company provided insufficient information to support the immediate need for this project. The Company's testimony, supporting exhibits, and audit responses provided a basis for what would be completed through the project, but failed to support why the added features of this project are necessary for the Company to implement at this time. (5 TR 5133.) This project will expand coverage of communication compliance and data loss prevention to more platforms used by the Company. (4 TR 2145-2146.) Additionally, in audit the Company confirmed with Staff that it plans to expand the current system, not replace it, as a part of this project. (S-18.0, pp. 1-3.)

Through audit Staff inquired about the need to expand the current system, specifically if the Company has experienced any issues with what it currently has that would warrant the need for expansion. The Company stated it has not experienced any issues with the current system's data loss prevention measures. (S-18.0, page 4 and 5.) Additionally, the Company shared the new features it would gain from this project but failed to provide why these features are needed right now. (S-18.1, p. 6.)

In rebuttal testimony, the Company asserts that the project will not implement a new system but expand coverage of the existing system. (4 TR 2356.) This was never a question or part of Staff's position for recommending a disallowance of this project. The Company further details the various areas that will be covered and expected gains from this project, which again was something

already shared with Staff through audit, and not a reason Staff recommended its adjustment.

The Company seems to address two separate systems in rebuttal. From the Company's initial filing it shared coverage would be extended to cloud applications, which encompasses areas like outbound emails, Teams, message chats, one Drive SharePoint, Copilot and channel communication. Similarly, in rebuttal the Company stated these same programs would be receiving the extended coverage and did not provide any additional information. (4 TR 2356.) The Company then shares new information pertaining to additional applications that were installed in the last 12 to 18 months that are part of the Company's operational environment. It further states that due to these additional applications being implemented the current security barrier does not fully cover this new landscape. (*Id.*) It is unclear how these new applications installed relate to the other cloud applications initially identified by the Company as needing extended communication compliance and data protection coverage. Additionally, if these applications, that were installed 12 to 18 months ago, are no longer protected, why was this lack of coverage not addressed immediately? If having complete security coverage was not a priority 12 to 18 months ago when the Company first installed these new features, it is unclear why it is important now.

The Company further states that communication compliance and data loss prevention need to be installed "across all platforms including email, Teams, Viva Engage, SharePoint, and OneDrive". (4 TR 2356.) The Company again provides a

list of areas that must be covered, but this time includes some different applications from the previous list shared in rebuttal and with Staff through audit. Staff finds these inconsistencies confusing and the lack of consistent straightforward information as to what specific areas need to have coverage, and why, is still unclear.

Finally, the Company shares various areas this investment will support. (4 TR 2356-2357.) Again, the outcome of this project was never questioned by Staff. The main concern Staff has is the lack of information supporting the immediate need for this project. Staff would also like to note that the Company shared new information in its rebuttal testimony stating that “these tools are required to maintain compliance across collaborative platforms and prevent violations that could trigger regulatory penalties.” (4 TR 2357.) Through audit, the Company shared this project would bring value through mitigating compliance risk, improving organization’s overall security posture and safeguard its brand reputation. (S-18.0, p. 6.) This information shared in audit and the information presented in the Company’s rebuttal testimony address the issues of compliance but does not provide concrete information as to whether the Company would violate compliance if this project was not completed now. If this was a serious concern, Staff would expect this to be directly addressed in audit when asked about current issues with the system or detailed in rebuttal. Staff does not believe the Company has provided enough information regarding these two issues to support the need for immediate action to prevent known consequences. Additionally, if the Company was

no longer in compliance Staff expects the Company would not wait for a rate case to request funding to fix this and instead address the pressing issue at the time it became known. Considering these factors, Staff notes the new information provided by the Company through its rebuttal but still does not see the immediate need for this project.

The Company failed to provide clear and concrete reasons as to why this project must be completed now. Additionally, they provided inconsistent information as to what systems need additional coverage. The Company detailed security gaps and maintaining compliance but did not address issues the Company is currently facing as a result of these two things or known imminent issues. The Company failed to provide additional information regarding the compliance, such as if the Company is currently violating compliance, when and why this was triggered, and any immediate issues it is experiencing as a result of this. Additionally, the cloud applications identified by the Company have been in use for a while and no issues or problems were reported. Similarly, the new applications addressed by the Company in rebuttal were installed 12 to 18 months ago. (4 TR 2356-2357.) If the issues presented in rebuttal were serious security and compliance concerns the Company would have ensured this gap in coverage was addressed immediately and not wait a year or longer. If they were not serious enough back then, it is unclear why they are now. Therefore, Staff recommends the Commission disallow the Communication Compliance and Data Loss Prevention (DLP) Diversification projects at this time. Additionally, if the Commission does not approve a full

disallowance of this project, Staff recommends a full disallowance of all overhead costs associated with this project. (5 TR 5135.) See Section III.B.4.a.iv. above for Staff witness Rogers discussion of overhead costs.

**e. Category five: Capital spending associated with IT-infrastructure operations should be reduced by \$2.647 million. (Appendix E, Lines 71-75.)**

Staff recommend capital expenditures for IT – infrastructure operations should be reduced by \$2.647 million, which reduces rate base by \$1.465 million. (Appendix E, Line 71-75.) This is composed of four adjustments described below.

**i. Adjustment one: Backup Environmental Growth. (Appendix E, Line 72.)**

**[References in the Record:** Staff witness Danielle R. Rogers 5TR 5066 –5067; Company witness Steven B. Ambrose, 4 TR 2260-2261, 2349–2351 Line 6; A-12 Schedule B5.7.7.]

Staff recommends that the ALJ and Commission disallow \$0.1 million in both the 2025 bridge period and the 2026 test year for the Backup Environmental Growth project. (5 TR 5066.) The Backup Environmental Growth project ensures IT devices have enough capacity for backup creation and secure storage. (4 TR 2161.)

Staff recommends this adjustment because in the two previous electric rate cases, Case Nos. U-21297 and U-21534, DTE has projected higher capital costs than were actually spent for this project. In Case No. U-21297, the Company projected a cost of \$0.5 million in the 2022 bridge period, however, the subsequent rate case, Case Number U-21534, shows an actual cost of only \$0.201 million in 2022. For

2023 costs, Case Number U-21297, includes a projected cost of \$0.507 million in the 11 months ending 11/30/2023, however in Case Number U-21534, the projection was reduced to \$85,000. Further, in the instant case, DTE requests recovery of the actual cost, \$85,000 in the 2023 historical year. Finally, regarding 2024 costs, the Company projected an investment of \$0.624 million in the Case Number U-21297 test year ending 11/30/2024, and in the 2024 bridge year in Case Number U-21534. In the instant case, the Company projects \$0.498 million in the 2024 bridge period. (5 TR 5066 - 5067.)

In rebuttal testimony, Company witness Ambrose disagrees with Staff's recommendation, stating that DTE is on track to meeting its projection for this project. He states that currently, \$0.357 million has been committed in 2025 for software licensing, hardware upgrades, and infrastructure improvements, as well as the associated labor costs. He states the remaining \$0.143 million "will be directed toward continuing migration efforts, including configuration, testing, and deployment activities". (4 TR 2350.)

As for projected costs in 2026, DTE affirms the full projected \$0.5 million cost for the Backup Environmental Growth investment will be used to migrate Avamar filesystem backups and transition from Dell Networker to Power Protect Data Manager (PPDM) to increase data security and backup resiliency. (4 TR 2350.)

Staff maintains its position and remains unconvinced the Company will spend the entire projected cost for its intended purpose. Staff is skeptical of Company witness Ambrose's note that completion of these tasks is critical to

maintain a secure and resilient backup environment and delay could reduce efficiency and increase security risks. If it was truly necessary and the cost was accurate, the Company would not have a history of spending substantially less than projected.

The Company has been approved significantly more than they spent for this project in prior cases. The Commission is unable to perform retroactive ratemaking to correct for this issue. Staff's recommendations aims to prevent this situation from occurring again, and to ensure any excess funds are not spent imprudently. For these reasons, the ALJ and the Commission should disallow 20% of the costs associated with this project, or \$0.1 million, in both the 2025 bridge year and the 2026 test year. If the Company spends the full projected costs, it can provide evidence in its next electric rate case to be reviewed for reasonableness and prudence.

**ii. Adjustment two: Network Hardening and Operations Project (Appendix E, Line 73.)**

**[References in the Record:** Staff witness Danielle R. Rogers 5 TR 5068-5069 ; S-12.11 p. 3; Company witness Steven B. Ambrose 4 TR 2165-2166, 4 TR 2351–2353; A-12 Schedule B5.7.7]

The ALJ and the Commission should disallow \$0.5 million in the 2026 test year for the Network Hardening and Operations project. (5 TR 5068.) This investment occurs annually to assess the Company's networks and implement operational system upgrades to fulfill the hardening requirements of network infrastructure. (4 TR 2166.)

Staff finds the full use of the projected cost in the test year is uncertain at this time. DTE requested recovery of \$0.881 million in the 2023 historical year, \$0.4 million for each of the 2024 and 2025 bridge years and is projecting an investment of \$0.9 million in the 2026 test year. Through audit, Staff asked for the scope of work to be completed each year. The Company responded that in 2023, it implemented LAN redundancy at 10 sites, implemented Power redundancy at 15 sites, and implemented WAN redundancy at two sites. In 2024 and 2025, the Company implemented network robustness that includes LAN redundancy, WAN redundancy, Power redundancy, VOIP changes at 11 and 9 sites, respectively. The 2026 scope also consists of implementing network robustness that includes LAN redundancy, WAN redundancy, Power redundancy, and making VOIP changes at critical sites. The Company did not identify the number of critical sites. Because the scope is nearly the same for 2024-2026, albeit an unknown number of critical sites in 2026, the investment should be similar. (5 TR 5068-5069.)

Although DTE's audit response provided the above project scope by year, Company witness Ambrose disagrees with Staff's recommendation, claiming that Staff's assumption that the scope is similar is incorrect and doesn't recognize the complexity and specificity of the work planned for 2026. (4 TR 2353.) He asserts the increase in costs in 2026 is due to essential enhancements in robustness and redundancy at critical sites supporting Fermi 2. He states Fermi 2 has experienced multiple outages over the past year affecting network communications at these 3 sites. Implementing redundancy will significantly reduce downtime risk and

improve operational resilience. He goes on to detail planned work at the Nuclear Operations Center (NOC) Building, with a projected cost of \$0.3 million, and at the Auxiliary Improvement Building (AIB) and General Training & Orientation Center (GTOC), with a projected cost of \$0.2 million. (4 TR 2352-2353.)

Staff maintains its position. Staff's analysis is limited by the information provided by the Company. It is the responsibility of the Company to provide evidence for all requested expenses. When asked through audit about the scope of this project, the Company provided the same planned work for each year. Staff cannot be aware of complexity or specificity of a project if it is not included in the Company's application or in response to audit/discovery. Providing this information in rebuttal testimony does not allow Staff enough time for a proper analysis. Additionally, the Company did not justify its entire 2026 \$0.9 million request.

For these reasons, the ALJ and the Commission should disallow \$0.5 million in the 2026 test year for the Network Hardening and Operations project.

**iii. Adjustment three: Digital Worker Experience EOL Electric. (Appendix E, Line 74.)**

**[References in the Record:** Staff witness Danielle R. Rogers 5TR 5069–5071; S-12.11 pp. 4-5; S-12.12; Company witness Steven B. Ambrose, 4 TR 2171-2172, 2339-2344; A-12 Schedule B5.7.7.]

The ALJ and the Commission should disallow \$1.596 million in the 2025 bridge year and \$0.215 million in 2026 for the Digital Worker Experience End of Life project. This investment occurs annually to replace devices such as laptops, desktops, monitors, and tablets that have reached their end of life. End of life is determined after five years of service because of degradation due to age and the

versions of the internal components (mother boards and storage & wireless components). (4 TR 2171.) This recommended adjustment is revised from Staff's testimony in which a recommended disallowance of \$1.563 million in the 2023 historical year, \$4.034 million in the bridge period (\$2.825 million in 2024 and \$1.209 million in 2025), and \$0.789 million in the 2026 test year was made. (5 TR 5070.)

Staff finds that DTE has not justified its full projected expense for the replacement of these devices. In testimony, the Company provided the number of laptops, desktops, monitors, tablets, and supplemental field worker devices scheduled to be replaced in 2023, 2024, 2025, and 2026. Through audit, the Company provided the unit cost of each type of device, and in additional audit provided a breakdown of the cost of each docking station, camera, mouse, headset, and dual monitor configuration. Staff analyzed the numbers of each equipment type to be replaced and their costs and found they do not calculate to the Company's projected expense. (5 TR 5070.)

In rebuttal testimony, the Company makes several arguments in disagreement with Staff's recommendation. First, Company witness Ambrose points out that Staff used \$5.201 million in its calculations instead of \$5.021 million, increasing the request by \$180,000. (4 TR 2340.) Staff agrees to this typographical error and has corrected it in future calculations.

Second, he states that Staff calculated the total cost for headsets, docking stations, and dual monitor configurations as only one unit each. Instead, the

projected cost includes varying quantities that calculate to \$0.251 million in 2024, \$0.410 million in 2025, and \$0.250 million in 2026. This would result in an undercalculation of \$0.908 million. (4 TR 2340.) While Staff disagrees with this argument since page 4 of Staff's Exhibit S-12.11 clearly shows the Company stated a count of 1 for this device type, it will agree to the recovery of this cost.

Third, Company witness Ambrose argues that Staff did not include labor costs required for device configuration, deployment, and testing. (4 TR 2340.) Staff agrees labor costs should be accounted for and has revised its calculations to include the Company's full projected labor cost in 2023 and 2025. However, in 2024, DTE has included \$1.597 million more in labor costs than approved in Case Number U-21534 and did not provide evidence for its use. (4 TR 2341, Table 2.) Staff recommends these excess labor costs be disallowed.

Additionally, included in the 2026 projected capital costs, the projected overhead costs are 13% of the total capital projected cost and therefore should be disallowed consistent with Staff's projected overhead cost disallowance.

Finally, Staff finds it necessary to correct the DTE's assertion that "the Commission rejected Staff's proposed disallowance of the Digital Worker Experience EOL project in Case No. U-21534 and approved recovery of the project, including labor costs." (4 TR 2343.) This statement is misleading and false. In that case, Staff revised its recommendation in its initial brief to include labor, however there were remaining dollars in the projected material costs that were unaccounted for. (See Staff's Initial Brief pp. 52-54 in MPSC Case No. U-21534.) The Company

accepted Staff's updated recommendation in its reply brief. (See DTE's Reply Brief p. 61 in MPSC Case No. U-21534). Subsequently, the Commission adopted the updated recommended disallowance that Staff and DTE agreed upon in the January 23, 2025 Order. (MPSC Case No. U-21534,1/23/25 Order, p. 187.)

For these reasons, the ALJ and the Commission should disallow \$1.596 million in the 2025 bridge year and \$0.215 million in 2026 for the Digital Worker Experience End of Life project.

**iv. Adjustment four: Field Worker Device EOL.  
(Appendix E, Line 75.)**

[**References in the Record:** Staff witness Danielle R. Rogers, 5 TR 5071–5073; S-12.11, pp. 6-7; Company witness Steven B. Ambrose, 4 TR 2175; Company witness Steven B. Ambrose, 4 TR 2345–2347 Line 8; A-12 Schedule B5.7.7]

Staff recommends that the ALJ and the Commission disallow \$0.135 million in the 2026 test year for the Field Worker Device End of Life project. (5 TR 5072.)

This project is an annual investment to replace end of life Mobile Data Terminal (MDT) devices. MDT devices are used to communicate with a centralized control system and are equipped with technology to provide maps and information systems for geographic locations, as well as other information important to the tasks performed by the devices they are mounted on. This allows field workers to resolve customer issues and inform customer service representatives so they can respond to customer questions. (4 TR 2175.)

Staff finds \$0.135 million in the test year is uncertain for its intended use within DTE's planned field worker device replacement schedule. Company

testimony states that the projected expense is the same for 2024, 2025, and 2026, however the number of MDTs planned to be replaced decreases over these 3 years. Through audit, the Company states that the projected cost is determined by the number of field worker devices planned to be replaced in a given year. In 2024, 165 field worker devices were replaced. In 2025, 155 field worker devices will be replaced and in 2026, 140 field worker devices are planned to be replaced. If 165 field worker devices were replaced for an actual cost of \$0.902 million, that means each device replacement costs \$5,467. For 155 device replacements, the total cost would be \$0.847 million, \$53,000, or 6%, less than projected in 2025. For 140 device replacements, the total cost would be \$0.765 million, \$0.135 million, or 15%, less than projected in 2026. (5 TR 5072.) Both 2025 and 2026 have Level 3 cost estimates. Since the difference in costs for 2025 is less than 10%, it is included in Staff's Level 3 cost estimate recommendation. The difference in cost is greater than 10% for 2026, hence Staff's alternate recommended adjustment. (5 TR 5073.)

In rebuttal testimony, DTE argues that Staff's cost analysis does not take into account anticipated increases in labor and equipment expenses over time. Company witness Ambrose states the Company's projections include changes in market prices, expected usage, and operational complexities over time. (4 TR 2346-2347.)

Staff maintains its position. Analyzing Table 6 in Company rebuttal testimony, the differences in cost change are well beyond cost increases over time. Between 2024 and 2025, the Company is factoring in a 6% change in the cost of

equipment and labor. Between 2025 and 2026, the Company is factoring in an 11% increase in equipment cost and a 10% change in labor cost. DTE has not justified these arbitrary cost increases.

Therefore, the ALJ and the Commission should disallow \$0.135 million in the 2026 test year for the Field Worker Device End of Life project.

**f. Category six: Capital spending associated with IT—enterprise data analytics should be reduced by \$439 thousand. (Appendix E, Lines 77-78.)**

**[References in the Record:** Staff witness Danielle R. Rogers, 5 TR 5073-5075; S-12.11, p. 8; Company witness Steven B. Ambrose 4TR 2198, 4TR 2353–2355; A-12 Schedule B5.7.8]

Staff recommends to the ALJ and the Commission that capital expenditures for IT – enterprise data analytics – DO productivity center should be reduced by \$439 thousand (\$.439 million) in the 2024 bridge period, which reduces rate base by \$263 thousand. (Appendix E, Line 78; 5 TR 5074.) This investment is for the implementation of a Performance Center for Distribution Operations (DO) to provide an accurate picture of productivity metric measurement and performance for Blue Sky and Grey Sky work. It also allows Distribution Operations to find and measure more productivity improvement initiatives. (4 TR 2198.)

Staff believes the DO Productivity Center might be “nice to have”, however it is an imprudent cost to pass onto ratepayers. DTE did not provide any evidence to show how this investment will increase safety, reliability, or cost savings for customers. This project had a Project Prioritization Score (PPS) of 2.2 on a scale of 1-9, meaning it aligns with only a couple of the Company’s priorities and may only

have a small impact on the seven weighted categories (strategic alignment, customer experience, employee engagement, affordability, cost benefit, operational reliability, and foundational capability). Further, this investment's execution timeline was April 2024-September 2024, however it was not projected or included in the Company's U-21534 rate case, which was filed on March 28, 2024. Staff questions the urgent implementation of this project, which wasn't planned ahead for, and only has a PPS score of 2.2. (5 TR 5074 - 5075.)

Company witness Steven B. Ambrose disagrees with Staff's recommendation and states that this investment is prudent and essential and benefits customers by enhancing operational efficiency, safety, and reliability. He testifies that the DO Productivity Center does this by equipping field crews with a Situational Awareness Dashboard that centralizes real-time data, identifies operational inefficiencies, and supports standardized process improvements, allowing improved customer experience by faster restoration times, reduced rework, and enhanced safety. (4 TR 2354 -2355.)

Staff maintains its position. Aside from stating that the situational awareness dashboard improves customer experience, it does not explain how it increases reliability, safety, or cost savings. Additionally, with a PPS score of only 2.2, this project will not have a large or substantial impact on any of the Company's priorities, one of which is customer experience. The Company also did not explain the urgency of this project's 2024 implementation or the lack of planning prior to the 2024 electric rate case.

For these reasons, the ALJ and the Commission should approve a total disallowance of the expenses associated with the DO Productivity Center project. This includes \$0.439 million in the 2024 bridge period.

**5. The Commission should reduce the Company's corporate staff capital expenditures by \$5.116 million.**

The Commission should reduce the Company's corporate staff capital expenditures by \$5.116 million, which reduces rate base by \$2.769 million. (Appendix E, Lines 81-85.) This is composed of three adjustments described below.

**i. The Commission Should Disallow \$1,362,000 in 2026 for Electric Vehicle Fleet and Maintenance Capital Expenditures. (Appendix E, Line 82.)**

[References in the Record: Staff witness Hansen, 5 TR 5172-5174, S-22.0.]

In direct testimony, Staff recommended a disallowance for the Company's Electric Vehicle Fleet and Maintenance expenses. (5 TR 5173.) Staff recommends this adjustment because the Company is projecting to spend over one million dollars more in 2026 than in any of the three previous years. (*Id.*) The Company claims that this is because it is expecting an increase in repairs on its vehicle fleet due to a lower level of new vehicle deliveries in 2025 and 2026; however, no information regarding how the Company estimated the dollar amount projected was provided. (*Id.*) In rebuttal, no party took issue with Staff's recommendation; therefore, the Commission should make Staff's recommended disallowance.

**ii. The Commission should disallow \$2.3 million of capital expenditures for Facilities-Construction & Upgrades – Courtyard (Appendix E, Line 83.)**

[**References in the Record:** A-12, Schedule B5.8, Line 13. Company witness Uzenski, 4 TR 2451. Staff witness Simmons, 5 TR 5185-5186. AG witness Coppola, 4 TR 3473.]

Staff witness Simmons recommends disallowing \$2.3 million of capital expenditures related to the courtyard space. (5 TR 5186.) As shown on Exhibit A-12, Schedule B5.8, Line 13, the Company has included \$2.3 million of capital expenditures in 2026 for the courtyard space. According to DTE Witness Uzenski, the purpose is to install furniture, a structure to house outdoor AV equipment and power to enable outdoor activities and events. (4 TR 2451.) Per audit response ZSS-1.3b, Exhibit S-23, Page 2, the Company claims that this courtyard space “will allow it to be used for centralized team meetings and events.” Additionally, the Company claims that “providing an additional large gathering space mitigates the need for (and cost of) off-site meetings.” (S-23, p. 3) The Company was asked to provide the benefit to ratepayers and failed to provide sufficient evidence that the costs offset the cost of off-site meetings. (5 TR 5185-5186.) Staff recommends disallowing \$2.3 million of capital expenditures for the courtyard space because it doesn’t provide any direct benefit to ratepayers. (*Id.*) Up until now, the Company has been functioning without this outdoor space. This Courtyard Space is more of a luxury want than a need and will most likely only be used seasonally, so it will be unused for a portion of the year.

In direct testimony, the Attorney General also recommended disallowing the courtyard space capital expenditures, stating “Spending \$2.3 million on this project seems unnecessary when the Company has many higher priority projects that can use that money to improve the electric grid. The Company has not presented any evidence that the use of this space will save costs elsewhere and is economically beneficial.” (4 TR 3473.)

The Company provided no rebuttal, therefore Staff recommends that ALJ and the Commission disallow \$2.3 million of capital expenditures related to the courtyard space.

**iii. The Commission Should Disallow \$700,000 in 2025 and \$800,000 in 2026 for Other Miscellaneous Expenses. (Appendix E, Line 84.**

**[References in the Record:** Staff witness Hansen, 5 TR 5174-5176, S-22.0 and S-22.2.]

In direct testimony, Staff recommended a disallowance for the Company’s Other Miscellaneous expenses. (5 TR 5175.) This recommended adjustment consists of two line items identified by the Company as representing emergent or placeholder spend. (5 TR 5175.) The first line item is labelled “Estimated Emergent/Placeholder Spend” and was described by the Company as, “Emergent and placeholder work is for potential added costs related to underground storage tanks and other currently unplanned/emergent work.” (5 TR 5175.) This line item also has no historic expenses. (5 TR 5175.) The second line item is labeled “Placeholder” and was described by the Company as being for the

placeholder/emergent portion of the human resources department. (5 TR 5176.) Staff recommended disallowance of this line item because the Company provided no basis for the cost estimates and no explanation for what this line item is for. (*Id.*) This line item also has no historic expenses. (*Id.*) In rebuttal, no party took issue with Staff's position; therefore, the Commission should make the disallowance recommended by Staff.

**6. The Commission should reduce the Company's charging forward capital expenditures by \$1.5 million, which reduces rate base by \$1.439 million. (Appendix E, Line 88.)**

[**References in the Record:** Staff witness Allan D. Freeman, 5 TR 5206-5208, S-25; Company witness Neal T. Foley, 4 TR 2640, A-12.]

Staff recommends reducing Charging Forward – EV Charging Hub capital expenditures by \$1.5 million, which reduces rate base by \$1.439 million. (5 TR 5207-5208; Appendix E, Line 88.) The Company should be allowed to recover \$99 thousand of capital that it invested in 2023-24. (5 TR 5208.) The Company undertook this investment in good faith before the federal funding requirements changed. (*Id.*)

Staff supports the Company's request to be able to record EV rebates as a Regulatory Asset beyond the forward test year, but not beyond the Transportation Electrification Plan timeframe of 2028. (5 TR 5206.) This change will ensure there are no interruptions to the Company's various EV programs due to the availability of rebates. (*Id.*)

Staff does not support the Company's request to have the ability to reallocate funding between its different EV programs. (5 TR 5207). Doing so would not allow for proper Commission oversight. The Company can apply any learnings in its next rate case and propose programmatic budget changes. (*Id.*)

Staff supports the Company's Direct Current Fast Charger, Level 2, and business fleet charger rebate requests. (*Id.*) Staff also supports the continuation of DTE's Emerging Technology Fund. (*Id.*) Lastly, Staff requests that the Company include analysis in its next Transportation Electrification Plan on how the One Big Beautiful Bill Act will impact EV adoption and load in its footprint going forward. (5 TR 5205.)

#### **IV. CAPITAL STRUCTURE AND RATE OF RETURN**

[**References in the Record:** Company witness Vangilder 3 TR 1588, 1592; ABATE witness Walters 4 TR 3275-3276; AG witness Coppola 4TR 3492; CUB witness Bandyk 5 TR 4719; Staff witness Ufolla 5 TR 4933, 4941-4942, 4953]

##### **A. Introduction**

In its initial filing, the Company requested an overall cost of capital of 6.03% (3TR 1588) with a return on equity (ROE) of 10.75%. (3TR 1592.) Staff recommends a lower cost of capital of 5.60%. (5 TR 4933.) Staff recommends an ROE range of 9.40% to 10.40% and used 9.80% as its recommended ROE in its overall cost of capital determination. (5 TR 4953.) Staff relied on the guidelines set forth by the Supreme Court in the *Hope* and *Bluefield* decisions in determining a reasonable ROE for DTE Electric. (5 TR 4941-4942.) Likewise, the Attorney

General, ABATE, and CUB<sup>6</sup> recommended lower overall cost of capital and ROE figures as well. The Attorney General suggests an overall cost of capital of 5.61% with an ROE recommendation of 9.85%. (4TR 3492.) ABATE recommends an overall cost of capital of 5.50% with a ROE of 9.50%. (4 TR 3275-3276.) CUB recommends an overall cost of capital of 5.26% with an ROE recommendation of 8.91%. (5 TR 4719) Staff maintains its recommendation of a 5.60% overall cost of capital with a 9.80% ROE, and the Commission should approve Staff's recommendation based on the reasoning provided below.

## 1. Capital Structure

**[References in the Record:** Company witness Lepczyk 4TR 2013, 2909, 2911-2912, 2916, 2918, 2927-2928; ABATE witness Walters, 4TR 3295-3296; AG witness Coppola 4 TR 3482-3493; CUB witness Bandyk, 5 TR 4719, 4738-4743; Staff witness Ufolla 5 TR 4933, 4935-4940.]

Staff did not make adjustments to the Company's recommended balances for short-term debt, preferred stock, job development investment tax credits, or net deferred income tax. Additionally, Staff did not dispute the Company's recommended cost rates for preferred stock, job development investment tax credits, or net deferred income tax.

## 2. Equity Ratio

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<sup>6</sup> CUB stands for Citizens Utility Board.

In its initial filing, the Company requested a 50.75% equity ratio. (4TR 2909.) Staff disagreed with this and recommended that the Commission maintain the Company's currently approved 50.00% equity ratio. (5 TR 4933) Likewise, the AG, ABATE, and CUB also support a 50% equity ratio. (4 TR 3482, 3296; 5 TR 4719.)

The Company argues that it must have a capital structure that is sufficient to maintain financial confidence and allow it to raise funds at reasonable costs. (4 TR 2911.) The Company states that having a highly levered or weak capital structure could result in higher cost of capital and the effects it can have on its credit rating. (4TR 2911-2912.) The Company recommends a 50.75% equity ratio. (4 TR 2013.)

In favor of the 50% equity ratio Staff argues that increasing the equity ratio puts more burden on ratepayers, the Company's credit metrics are robust and do not warrant a rise in equity ratio, the Company issued more debt than forecasted in its initial filing, and the Commission's clear preference for a balanced equity ratio. (5 TR 4935-4938) Similarly, the AG explains the following points support a 50% equity ratio; the Commission has been consistent in its directive for utilities to operate at a 50/50 capital structure, the Company's strong credit metrics, the Company's equity contributions from its parent company, the favorable regulatory environment of Michigan, and the peer group's equity ratio being at 42.5%. (4TR 3483-3492.) ABATE also makes similar points in favor of a 50% equity ratio including the lower equity ratio of the proxy group and the Commission's previous

directives. (4 TR 3295-3296.) Finally, CUB points again to the Commission's previous directives, the increased cost of equity as opposed to debt, the Company's robust credit metrics, and lays out a brief analysis of the Company's interest coverage ratio at a 50% equity ratio. (5 TR 4738-4743.) All these arguments show that the Company's position is not justified by its points as it is not heavily levered and is not in peril of losing its current credit rating.

In rebuttal, the Company restated that maintaining a sound capital structure is essential but did not provide any additional reasoning or provide any substantive evidence disproving the other party's positions. (4 TR 2927.) Thus, the Commission should approve Staff's recommended capital structure with an equity ratio of 50.00%.

### **3. Long Term Debt Rate**

The Company requested a long-term debt rate of 4.24%. (4 TR 2916.) Staff updated the Company's projections and recommended a long-term debt rate of 4.27%. (5 TR 4939-4940) This adjustment stems from both an update to the Company's actual debt issuances being higher and Staff using more recent treasury projection for the new issuances which was a slight reduction to the Company's initial projection. (5 TR 4939-4940.)

In rebuttal, the Company disagreed with Staff's change to the debt rate, increasing its own recommendation further to 4.29%. (4TR 2928) However, the Company did not submit any testimony to actually dispute Staff's rate or to prove it unreasonable. Instead, the Company simply took the opportunity to include only

the updated actual debt issuance figures to increase its cost of debt while ignoring Staff's updated treasury projections and re-iterating its own from its initial case. Thus, the Commission should approve a long-term debt rate of no higher than 4.27%, as recommended by Staff.

### **1. Short Term Debt Rate**

The Company requested a short-term debt rate of 4.75%. (4 TR 2918.) Staff disagreed and recommended a 3.85% rate for short term debt. (5 TR 4940.) The difference between these was that Staff used a Short-term Overnight Financing Rate (SOFR) projection as opposed to the Company which used the current rate. (5 TR 4940; 4 TR 2918.) Likewise, the AG reduced the short-term debt rate to 3.91% by utilizing a projected growth rate found in discovery. (4 TR 3493.) Though they use different sources and thus have different figures, Staff and the AG's adjustments are of the same nature.

In rebuttal, the Company argued against the use of "consistently overly-optimistic forecasts" and advocated for the use of current short-term cost rates in the instant case. (4TR 2928.) The use of projected rates has been the standard used by witnesses in previous cases and better aligns with the test year. The Commission has a precedent of relying on projected rates in past cases, and no compelling argument has been made in favor of using current rates. The Commission should approve a short-term debt rate of 3.85% based on a projected interest rate, as recommended by Staff.

## 2. Return on Equity

[References in the Record: Company witness Nelson, 4TR 2943, 2967, 2973, 2976, 2979; ABATE witness Walters, 4 TR 3275-3276, 3306-3315, 3321, 3330, 3336-3345; AG witness Coppola 4 TR 3492, 3498, 3501-3502, 3507-3511; CUB witness Bandyk, 5 TR 4711, 4721, 4730, 4734-4735; Staff witness Ufolla 5 TR 4941-4943, 4945-4953.]

Staff recommended a ROE range of 9.40% to 10.40% and used 9.80% as its recommended ROE in its overall cost of capital determination. (5 TR 4941) Staff relied on the guidelines set forth by the Supreme Court in the *Hope* and *Bluefield* decisions in determining a reasonable ROE for DTE Electric. (5 TR 4941-4942.) Since DTE Electric is not publicly traded, Staff used a group of sixteen publicly traded electric utility companies to help establish a reasonable cost of equity range for the Company. Staff used six criteria to establish its proxy group; a proxy company must 1) be listed as an Electric Utility by Value Line, 2) have a full Value Line report available, 3) be currently paying dividends to shareholders, 4) must not be the target of a merger or acquisition, 5) must have an investment grade credit rating, and 6) must have a net plant between \$8 billion to \$55 billion. (5 TR 4943) The proxy group's statistics were used to provide a reasonable approximation of the Company's required cost of equity in Staff's DCF and CAPM cost of equity models. Additionally, Staff relied on a risk premium analysis and a review of other state commission ROE decisions to help reach a recommended cost of equity for DTE Electric. (5 TR 4941.)

The Company's cost of capital witness, Jennifer Nelson, sponsored DTE Electric's 10.75% ROE recommendation. (4 TR 2943.) Witness Nelson submitted rebuttal disputing certain portions of Staff's ROE analysis and 9.80%

recommendation. Additionally, the Attorney General recommends an ROE of 9.85%, (4TR 3492.) ABATE recommends an ROE of 9.50%, (4TR 3275-3276) and CUB recommends an ROE of 8.91%. (5 TR 4711.)

### **3. Models**

#### **i. DCF Model**

The DCF model assesses that investors value stocks by ‘discounting’ expected future cash flows, attributed to securities, to present day. This ‘discounting’ process applies a capitalization rate to the future cash flows, both dividends and capital gains.

Staff obtained the data for its DCF analysis using statistics from its proxy group and growth estimates from industry experts. Staff’s DCF analysis yielded an average ROE estimate of 9.61%. (5 TR 4945) The AG performed its own DCF analyses as well. The AG’s models indicated an average required ROE of 9.80%. (4TR 3498) ABATE presented multiple DCF analyses which had results ranging from 8.36% to 10.65%; however further explained that only the models yielding 8.36% to 9.00% were given primary weight (4 TR 3306-3315) CUB performed two DCF analyses with outputs of 8.38% and 9.65%. (5 TR 4721)

The Company presented three DCF analyses using various time frames which ranged from 10.52% to 10.68%. (4 TR 2967) Staff’s testimony also addressed the Company’s DCF analysis and ROE estimate. Staff disagreed with the Company’s DCF models that included 30- and 180-day models; Staff noted that the

90-day model was not objected to, but the Company's model resulted in a higher ROE estimate due to when the input data was acquired. (5 TR 4945-4946)

## **ii. CAPM**

The CAPM model infers that investors are exposed to two types of risk, diversifiable (firm specific) and non-diversifiable (market) risk. The CAPM suggests that an investor is fully invested in a portfolio of stocks and thus eliminates, or greatly reduces, firm specific risk and is only exposed to market risk. The risk of an asset and thus the investor's required return is a function of the risk of that asset compared to the market. This market risk is characterized by the beta coefficient. Therefore, to estimate a cost of equity using the CAPM, one needs a risk-free rate, an estimate of beta for the proxy group, and a market return for a wide portfolio of assets. Staff used a long-term U.S. Treasury bond yield forecast for its risk-free rate, the proxy group betas from Value Line, and a market return from a wide variety of assets from 1928 - 2024. (5 TR 4947-4948.) Staff's CAPM analysis produced an average ROE estimate of 9.86%. (5 TR 4948.) The AG also produced a CAPM which resulted in a 9.97% ROE output. (4 TR 3501) ABATE performed twelve CAPM analyses with outputs ranging from 7.18% to 10.54% with various betas and risk premiums. (4 TR 3330.) CUB performed four CAPM analyses with results ranging from 7.85% - 9.80%. (5 TR 4721.)

The Company presented eight CAPM analyses with various alterations including current and projected risk-free rates, historical and projected methodologies, and an empirical adjustment, ranging from 11.51% to 14.61%. (4 TR

2973, 2976.) Staff's testimony also addressed the Company's CAPM analyses and corresponding ROE estimates. Staff disagreed with the Company's use of current risk-free rates, the Empirical CAPM (ECAPM), and forward looking models. (5 TR 4949-4950.) Staff outright objects to the methodology of using a current risk premium and ECAPM; alternatively, Staff explains that the forward looking CAPM is not academically incorrect, but that the results are a clear outlier and unhelpful for determining a reasonable ROE. (5 TR 4950) Similarly, the AG and ABATE also rejects the Company's forward looking CAPM and ECAPM. (4 TR 3507-3511, 3336-3345.) CUB rejects the ECAPM on the basis that it has not been recognized historically by the MPSC. (5 TR 4730.)

### **iii. Risk Premium**

The risk premium approach examines the spread between historical electric utility realized stock returns and historical bond yields and develops a cost of equity estimate by incorporating the historical data with current bond data. Staff used a return period of 1931 through 2024 to obtain its historical market risk premium. Staff provides a Utility bond-based risk premium model as well as a Treasury bond-based model. (5TR 4951.) The risk premium model produced ROE estimates of 10.31% based on Utility bonds and 10.32% for the treasury-based method. (5 TR 4951.) The AG and ABATE also provide Risk Premium analyses. The AG's Risk Premium model yields a result of 9.86%. (4 TR 3502.) ABATE's Risk Premium analyses show results ranging from 9.87% to 10.06%. (4 TR 3321.)

The Company uses two regression-based Risk Premium models with current and projected treasury rates which output results of 10.20% and 10.37%. (4 TR 2979) Staff addresses the Company's Risk Premium analysis not only rejecting the Company's "current" model for not aligning with the test year but also noting that the use of approved ROEs allows the Company to use less than 50 years of data compared to Staff's nearly a century of market-based data. (5 TR 4952.) CUB also disputed the use of approved ROEs in a Risk Premium. (5 TR 4734-4735.)

#### **4. Other Commissions' Decisions**

Staff reviewed the authorized rate of return decisions rendered by other state commissions from 2024 and 2025. The average authorized ROE from those decisions was 9.74% for 2024 and 9.68% for 2025. (5TR 4953.) The ROE data was provided by the Regulatory Research Associates, which is a unit of S&P Global Market Intelligence.

#### **5. Response to Company witness Nelson's rebuttal critique**

**[References in the Record:** Company witness Nelson, 4 TR 3028, 3040-3041; AG witness Coppola, 4 TR 3503-3504; CUB Witness Bandyk 5TR 4734; Staff witness Ufolla, 5 TR 4950, 4952.]

In rebuttal witness Nelson, on behalf of DTE Electric, criticizes Staff's and other intervenors' ROE analysis. Most critiques are a rehash of her initial testimony and were addressed in Staff's and intervenors testimony. None of this rebuttal should persuade the Commission from approving Staff's Cost of Capital positions. Witness Nelson makes several adjustments to Staff's analysis, the only one of which

makes a difference beyond about 10-15 basis points being the adjustment to Staff's Risk Premium, to which a response is below. (4 TR 3028.)

In rebuttal, witness Nelson states the primary concern with Staff's Risk Premium analysis is that it does not account for the inverse correlation between bond yields and equity risk premium, and secondarily that Staff's analysis is not forward looking. (4 TR 3040.)

To create a forward-looking risk premium, witness Nelson suggests using a DCF of the S&P 500 Utility Index. (4 TR 3040-3041.) This is a similar method to witness Nelson's forward looking CAPM; the same CAPM methodology Staff previously established was out of alignment with any other ROE analysis presented by Staff or DTE. (5 TR 4950.) Again, this method has academic merit, it does not create a reasonable result that is useful for setting a reasonable ROE in the current market. Instead, this adjustment puts the Risk Premium out of alignment with the other models.

Witness Nelson does not give any specific rebuttal on regression analysis aimed at Staff beyond initial testimony but does rehash her position on using authorized ROE for the Risk Premium model. (4 TR 3041.) However, as pointed out by Staff, using authorized ROE as an input to set a reasonable ROE is circular in nature. (5 TR 4952.) CUB also cites the circularity of this methodology. (5 TR 4734.) The AG weighs in on the use of authorized ROE, appropriately explaining that this method uses authorized ROEs as a substitute for investor expectations and has no validity in determining an appropriate ROE in rate cases. (4TR 3503-

3504.) Additionally, Staff's methodology has approximately twice the data stretching near a century for greater statistical accuracy. (5 TR 4952.) For all these reasons above, the Commission should approve an ROE of 9.80% as recommended by Staff.

## **V. NET OPERATING INCOME**

Reduced to its essence, Adjusted Net Operating Income (NOI) is the difference between a company's operating revenues and operating expenses for the projected test year. *In re Detroit Edison's 2010–2011 Rate Case*, MPSC Case No. U-16472, 10/20/2011 Order, p. 41.

### **A. Staff recommends an adjusted net operating income of \$1.219 billion.**

In its initial filing, the Company recommends an adjusted net operating income (NOI) of \$1.108 billion, while Staff recommends an adjusted NOI of \$1.219 billion, which is \$110.895 million greater than the Company's projection. (Appendix A, Line 2.)

Staff initially filed a projected net operating income of \$1.218 billion, an increase of \$110.060 million from the Company's originally filed net operating income of \$1.108 billion found on Exhibit A-1, Schedule A1, Line 2. (5 TR 4881.) In this brief, Staff has updated its case and now projects a net operating income of \$1.219 billion. (Appendix A, Line 2.) A reconciliation of the updates Staff has made in this brief can be found on Appendix F, Lines 14-41.

Differences between the Staff's and the Company's total adjusted NOI are due to Staff adjustments to various Company revenue and expense projections as detailed below.

**1. Staff recommends total operating revenues of \$5.725 billion.**

[**References in the Record:** David W. Isakson, 5 TR 4901-4903, S-3, C3; Uzenski, 4 TR 2421-2422, 4 TR 2494-2495; Kindschy, 5 TR 5105; Ausum, 5 TR 5238.]

DTE projects that its total operating revenues will be \$5.718 billion in the projected test year, which is \$6.486 million less than Staff's projection of \$5.725 billion. (Appendix C, Column e, Line 1, 66 and 67.) Staff's sales revenue, base fuel and purchased power revenue, and other revenue and R2 rider are discussed below in Section V.A.1.b, c and d respectively.

**i. The test year forecast of deliveries and customers should be increased.**

[**References in the Record:** Staff witness Paul Ausum, 5 TR 5235-5239, S-27.0, S-27.1; Staff witness Hunter Hansen, 5 TR 5176-5178, S-22.0; Company witness Markus B. Leuker, A-5, A-15.]

Staff witness Paul Ausum recommends that the test year residential deliveries forecast be increased by 24,159,596 kilowatt-hours (kWh) and the commercial (small commercial & industrial) deliveries forecast be increased by 5,005,610 kWh. (5 TR 5235, S-27.1, page 2, column k, lines 1-2.) Witness Ausum also recommends that the test year forecast for the number of residential customers be increased by 3,944 and the number of commercial customers be increased by 735. (5 TR 5236, S-27.1, page 1, column k, lines 1-2.) Staff's recommended adjustments

are related to the discovery of AMI meters that have been transmitting usage data to the Company but are not registered to a customer account. (5 TR 5176-5178, 5236.) Because of this fact, the Company does not have a customer account to bill for the usage, and the kWh that would otherwise provide revenue to the Company is recorded as a “loss” and contributes to the losses and company use portion of total system output. This is unreasonable, especially because the Company has had knowledge of the issue since 2017, and both the number of unregistered meters and the total usage for those unregistered meters has grown. (5 TR 5236, S-22.0, page 10.) Witness Ausum computed the three-year compound annual growth rate (CAGR) using data from 2021-2024 for both the number of residential and commercial unregistered meters and the kWh usage associated with them and used these growth rates to forecast the number of meters (customers) and their usage in the test year. (5 TR 5237.)

No party to the case filed rebuttal disputing witness Ausum’s sales and customer count adjustment. The ALJ and the Commission should adopt a test year residential deliveries forecast that is 24,159,596 kilowatt-hours higher than the Company’s and a small commercial and industrial deliveries forecast that is 5,005,610 kWh higher than then Company’s. Staff’s sales adjustments affect Exhibit A-15, Schedule E1, page 1, line 3, columns b and c. When added to the Company’s forecast, the 2026 service area test year deliveries forecast with Staff’s adjustment amounts to 15,383 Gigawatt-hours (GWh) for residential customers and 10,849 GWh for small commercial and industrial customers. The ALJ and the

Commission should also adopt a test year residential customer count forecast that is 3,944 customers higher than the Company's, and a small commercial and industrial customer count forecast that is 735 customers higher than the Company's. Staff's customer adjustments affect Exhibit A-15, Schedule E6, page 1, line 8 columns b and c. (5 TR 5235-5236, 5239.) When added to the Company's forecast, the service area 2026 test year customer forecast with Staff's adjustment amounts to a twelve-month average service area customer count of 2,092,452 residential customers and 214,653 small commercial and industrial customers.

Staff made adjustments to 1) sales revenue, 2) base fuel and purchase power revenue, and 3) other revenue and R2 rider as detailed below.

**b. Staff recommends sales revenues of \$4.252 billion.**

Staff recommends an increase in sales and customer count as a result of Staff's sales forecast, which increases present revenue and lowers the revenue requirement, by \$5,722,000. (S-6, Schedule C3, Line 3, column c.) The increased sales forecast is due to the inclusion of unregistered meters. (5 TR 4902.) This amount includes increased revenue from electric sales, customer charges, and PSCR charges. (*Id.*)

**c. Staff recommends base fuel and purchase power revenue of \$1.352 billion.**

[**References in the Record:** Willis, 4 TR 1726-1728, A-13, Schedule C4; Kindschy, 5 TR 5105; Ausum, 5 TR 5235-5238.]

The Company projected that it would receive \$1.353 billion in base fuel and purchase power revenue, which is \$983 thousand less than Staff's projection. (Appendix C, Column c, Line 1, 66, and 67.) Staff witness Paul Ausum recommends an adjustment to the Company sales forecast due to unregistered meters. (5 TR 5235-5238, S-27.1.) Staff witness Ausum's adjustment to the sales forecast results in an increase to power supply revenues that must be offset with a corresponding increase to fuel and purchased power expense. (5 TR 5235-5238; 5 TR 5105.)

Staff witness Lisa M. Kindschy testifies that fuel and purchased power expense must be increased in order to keep the power supply revenues equal to the power supply expenses in the case. She explains that this adjustment is necessary so that power supply expenses do not have an impact on the revenue deficiency since these expenses are reconciled in the PSCR process. Staff witness Kindschy describes that the amount that power supply costs needs to be increased is \$982,576 ( $\$982,576 = \$33.69/\text{MWh} \times 29,165.207 \text{ MWh}$ ) and is calculated by multiplying the Staff's sales adjustment by the PSCR base at sales level. (5 TR 5105.) Staff would note that for this case, Staff is reducing fuel and purchased power revenue instead of increasing fuel and purchase power expense, which has the same effect on the revenue deficiency. Staff recommends a fuel and purchase power expense of \$1.352 billion, an increase of \$982,576.

- d. Staff recommends other revenue and R2 of \$120.076 million.**

**[References in the Record:** Staff witness David W. Isakson, 5 TR 4903,S-3, Schedule C3; Company witness Theresa M. Uzenski, 4 TR 2495.]

Staff recommends other revenue and R2 rider of \$120.076 million, which is \$1.747 million greater than the Company's projection of \$118.330 million. (Appendix C, Column d, Lines 1, 66, and 67.) Staff's recommendation is composed of two adjustments described below.

**i. Staff recommends a \$2.693 million increase to Other Operating Revenue (Appendix C, Line 8.)**

Staff recommends an increase in present revenue by \$2,693,000 to reflect the three-year historical trend in operating revenue. (Isakson, 5 TR 4903.) Staff found that the Company had been collecting increasing revenue in late payment, miscellaneous service, and rent while the Company's other revenues in FERC account 456 were decreasing. (*Id.*) Staff applied the three-year trends for each affected account to the Company's proposed test year amounts. (S-3, Schedule C3, Page 2 of 2.)

The Company disagreed with Staff's adjustment to other operating revenues. The Company argued that the Company set the revenue in the projected test year equal to the historic test year amount, which is consistent with methodology used in prior rate cases. (4 TR 2495.) However, Staff identified trends in certain other operating revenue accounts, which should be incorporated into revenue projections because it is reasonable to assume that those trends will continue in the test year. Therefore, incorporating these trends is appropriate so that present revenue more

accurately reflects what is expected during the test year. For this reason, the Commission and ALJ should approve Staff's adjustment to other operating revenue.

- ii. Staff recommends for the Cost of Service Study (COSS) and Uncollectible Expense Cost Reallocation—a \$947 thousand reduction to uncollectible expense for payment stability plan and a \$947 thousand decrease to present revenue for the Payment Stability Plan. (Appendix C, Line 9.)**

**[References in the record:** DTE witness Jason Sparks 4 TR 2737; DTE witness Theresa Uzenski 4 TR 2474-2475; A-13 C5.8.1; Staff witness Elaina Braunschweig, 5 TR 5215-5225, S-26.0; Company witness Jason Sparks (rebuttal), 4 TR 2742-2743.]

In direct testimony, DTE Energy witnesses Jason Sparks and Theresa Uzenski sponsored testimony proposing cost recovery of \$1,010,841 in Payment Stability Plan pilot expenses. (4 TR 2474-2475, 2737.) The Payment Stability Plan pilot was a two-year residential energy assistance pilot approved by the Commission in its April 21, 2021 Order in MPSC Case No. U-20929. The pilot required participating customers to pay 6% of their income for single-commodity energy service and 10% of their income for dual-commodity service and forgave 1/24th of the customer's arrears each month of the two-year pilot. The pilot has concluded and is now in its analysis and partial cost recovery phase. The Company recorded the expense as uncollectible expense. (A-13 C5.8.1.) Staff argued in direct testimony that the Commission did not previously approve the Company to record the expense in uncollectible expense, rather as a regulatory asset in the short-term. MPSC Case No. U-20929 4/21/2021 Commission Order, p. 3. (S-26.0.) Staff disagreed with recording the expense in uncollectible expense since Federal Energy

Regulatory Commission (FERC) Uniform System of Accounts advises that utilities should book expenses to the account that they would have been booked to in the previous period that it would have been incurred if not for the Commission allowing it to be booked as a regulatory asset. (5 TR 5221.) Staff outlined three different categories of expense that made up the \$1,010,841 in Payment Stability Plan pilot expenses: arrears forgiveness, bill subsidy credits (also known as gap payments), and on-time payment benefit credits. (5 TR 5222.) Based on FERC accounting guidance, Staff contends that arrears forgiveness could plausibly be incurred in uncollectible expense, but since gap payments and on-time payment credits are similar bill payment assistance credits like the incumbent Residential Income Assistance (RIA) Credit, Low Income Assistance (LIA) Credit, and Residential Senior Citizen (RSC) Credit, they should receive the same cost allocation treatment as the credits; as a revenue offset in the cost of service study. (5 TR 5222-5223.) Since the Company provided no evidence through direct testimony nor audit responses that all assistance costs associated with the PSP pilot would have resulted in recorded uncollectible expense, Staff's position is better supported than that of the Company's. (5 TR 5223; S-26.0).

In summary, Staff's adjustment is: a \$946,779 reduction to line 12 "Low Income Payment Stability Plan Pilot Amortization Expense" on Schedule C5.8, Uncollectible Expense, sponsored by Staff witness, Shannon Rueckert. A \$946,779 reduction to present revenue, recorded in the "Revenue Credits" section and "Provision for Rate Refunds (RIA/LIA)" account in the Input1 tab of the COSS,

sponsored by Staff witness Mark Pung. \$946,779 is the total of on-time payment benefits and gap payments (\$945,364+\$1,414.50). (5 TR 5224.) This adjustment does not impact the revenue requirement.

In rebuttal testimony, the Company stated that it did not object to Staff witness Braunschweig’s proposal to allocate PSP expenses through the COSS calculations and removing \$1.0 million from uncollectible expense. (4 TR 2742-2743.)

**2. Staff recommends total operating expenses of \$4.566 billion for the projected test year.**

Staff’s recommended total operating expenses of \$4.566 billion is \$104.409 million less than the Company’s projection of \$4.671 billion. (Appendix C, Column n, Lines 1, 66, and 67.) Staff breaks down this \$104.409 million difference, by category, and explains the difference below:

	(millions)
Other O&M	\$ (112.468)
Depreciation & Amortization	(28.453)
Property Tax	(3.698)
State & Local Income Tax	9.639
Federal Income Tax	<u>30.570</u>
<b>Total Difference in Operating Expense</b>	<b>\$104.409</b>

**a. Staff recommends a fuel and purchase power expense of \$1.353 billion.**

Staff recommends fuel and purchase power expense of \$1.353 billion, which is equal to the Company's initially filed projection. (Appendix C, Column f, Line 67.)

**b. Staff recommends an Other O&M expense of \$1.280 billion.**

Staff's initially filed projected operations and maintenance expense is \$1.285 billion, a decrease of \$107.686 million from the Company's originally filed projected operations and maintenance expense of \$1.393 billion found on Exhibit S-3, Schedule C1, Line 4. In this brief, Staff has updated its case and now projects an operations and maintenance expense of \$1.280 billion. (Appendix C, Column g, Line 67.) A reconciliation of the updates Staff has made in this brief can be found on Appendix F, Lines 21-32.

Staff recommends Other O&M expense of \$1.280 billion, which is \$112.468 million less than the Company initially filed projection of \$1.393 billion. (Appendix C, Column g, Lines 1, 66, and 67.) Staff proposes the following adjustments to Other O&M Expense:

i.	GENERATION	(millions)
	1. Steam Power Generation	\$(20.158)
	2. Fuel Supply & MERC Fuel Handling	(0.092)
	3. Nuclear Power Generation	(1.354)
	4. Hydraulic Power Generation	(0.131)
	5. Other Power Generation	(5.512)
ii.	DISTRIBUTION	
	1. Inflation	(3.223)
iii.	UNCOLLECTIBLES	

1.	Payment Stability Plan	(0.947)
2.	Uncollectibles	(0.614)
iv.	REGULATED MARKETING	
1.	DR Call Center	(0.300)
2.	Inflation	(0.244)
v.	CORPORATE SUPPORT	
1.	Incentive Compensation	(35.838)
2.	Restricted Stock	(7.730)
3.	Communication Compliance & DLP	(0.283)
4.	Customer Insight Platform App Health	(0.100)
5.	Customer Relationship and Billing Program	(2.695)
6.	DTE Mobile App Application Health	(0.170)
7.	Outage WISMO and Map Sustainment	(0.249)
8.	Outage WISMO, PPS, and Map Enhancement	(0.525)
9.	Projects with level 2 cost estimates	(0.016)
10.	Projects with level 3 cost estimates	(2.086)
11.	Inflation	(23.065)
vi.	PENSION AND BENEFITS	
1.	Employee Pension and Benefits	(7.136)
	<b>Total difference in O&amp;M Expense</b>	<b>\$(112.468)</b>

**i. Staff recommends reducing generation O&M expense by \$27.246 million.**

Staff recommends reducing generation O&M expense by \$27.246 million.

(Appendix C, Column g, Lines 11-33.) This is composed of four categories of adjustments described below.

**ii. Staff recommends reducing Steam Power Generation O&M expense by \$20.158 million. (Appendix C, Line 12-19.)**

**[References in the Record:** Guillaumin, 3 TR 647, A-13 Schedule C5.1; Kindschy, 5 TR 5093-5102, 5105-5106, S-15.0-15.3, S-15.6; Coppola, 4 TR 3528-3532, AG-45-47]

Staff recommends reducing Steam Power Generation O&M expense by \$20.158 million. (Appendix C, Line 12-19.) Staff witness Lisa M. Kindschy recommended eight adjustments to Steam Power Generation O&M expenses.

Staff's first four adjustments to the Company's Steam Generation O&M expenses are for projects that Staff identified as being one-time or infrequent projects. Under footnote 7 on Exhibit A-13 Schedule C5.1, the Company made several adjustments to the adjusted historical test period to arrive at its projected test period. (3 TR 655-658.) Through discovery, Staff witness Kindschy determined that many of these adjustments under footnote 7 are for one-time or infrequently performed projects. (5 TR 5095, S-15.1.) Since rate cases are filed at the discretion of the Company, witness Kindschy determined that one-time and infrequent expenses should be recovered over a period of two years to protect rate payers from unreasonable future rates as well as providing the Company recovery of its expenses. Therefore, Staff witness Kindschy divided all one-time and infrequent expenses in half to allow recovery over two years. Staff recommends the following reductions to Steam Power Generation O&M expense for projects that are one-time or infrequent: a reduction of \$2,333,500 for the Belle River Power Plant (BRPP) Unit 2 Turbine Support Restoration (Appendix C, Line 12), a reduction of \$250,000 for the BRPP Unit 1 Operational Improvements Post Conversion – Belle River

Startup Study and Tuning (Appendix C, Line 13), a reduction of \$800,000 for the BRPP Unit 1 Operational Improvements Post Conversion – Belle River Chemical Resin Replacements (Appendix C, Line 15), and a reduction of \$3,843,000 for the Monroe Reliability Maintenance (Appendix C, Line 16). (5 TR 5095-5095, S-15.0, S-15.1, pp. 3-4.)

Based on the information at the time, Staff witness Kindschy determined that spreading one-time and infrequent O&M expenses over two years is the most reasonable option for both ratepayers and the Company. Witness Kindschy stated that DTE Electric has been filing rate cases recently on a one-to-two-year cadence; however, there have been announcements that DTE Electric is in discussions with several data centers for up to seven gigawatts of new load. She explained that this new load growth potential combined with all other considerations that go into a rate case has the possibility to change the frequency of future rate case filings. (5 TR 5104.) As such, witness Kindschy recommended that it may be appropriate for the Commission and the ALJ to spread the one-time and infrequent costs identified in this case for Steam Power Generation and Other Power Generation over a longer number of years, such as 3 or more, if the dynamics of rate case filings change during the course of this case. Witness Kindschy asserted that this strikes a balance between giving the Company recovery of its expenses but ensuring that they do not over-recover a one-time expense if rates are in effect for more than one year. (5 TR 5104-5105.)

Staff's fifth adjustment is a reduction of \$3,000,000 for the BRPP Unit 1 Operational Improvements Post Conversion – Belle River Unit 1 Boiler Chemical Cleaning. (Appendix C, Line 14.) Through discovery, Staff witness Kindschy learned that this project is moving from 2026 to 2027 and that \$2.4 million of O&M expense will transition out of the test period. (5 TR 5096, S-15.1, p. 1.) For the same reasons previously described for one-time projects, Staff witness Kindschy reduced the remaining expenses in the test year of \$1,200,000 by half. Staff recommends the Belle River Unit 1 Boiler Chemical Cleaning be reduced by \$3,000,000 which is the sum of \$2,400,000 that the Company identified would transition out of the test period and \$600,000 by reducing the remaining expenses in half. (5 TR 5096.)

In rebuttal, Company witness Margaret E. Guillaumin stated that the Commission should either provide full recovery in this case for one-time expenses or provide recovery of the other half of the O&M expenses adjusted for the time value of money in the Company's next rate case. (3 TR 667-668.) Staff disagrees.

First, this assumption is predicated on DTE Electric filing another rate case shortly after the current one is concluded. Staff highlighted the ambiguity of potential new load which could ultimately impact the frequency of the Company's next rate case. (5 TR 5104-5105.) Second, DTE Electric's proposal to include what it considers the missing half of its O&M expenses for one-time projects assumes that the projections will be spent exactly as proposed in this case. Staff would argue that the actual amounts could be higher, lower, or not incurred at all for a

variety of reasons, and thus, automatically including half of a projected amount in future rates is not reasonable. For these reasons, the Commission and the ALJ should adopt Staff's reductions for one-time and infrequent O&M projects and reject DTE Electric's proposal to automatically include half of the time-adjusted one-time O&M expenses in the Company's next rate case.

Staff's sixth adjustment is a recommended reduction to Belle River fuel handling O&M expenses. (Appendix C, Line 17.) Staff witness Kindschy testified that Belle River fuel handling O&M expenses should be reduced by 1/4 since Belle River Unit 2 will be out of service for its conversion to natural gas and no longer using coal during the last quarter of 2026. In addition, witness Kindschy recommended that the remaining amount of fuel handling expenses should be reduced by half since the Company should be ramping down spending at its Belle River coal facilities, as well as only spending O&M that is absolutely necessary to support operations. (5 TR 5097-5098.)

To make these adjustments, Staff witness Kindschy began with 2024 actual Belle River fuel handling expenses and applied Staff's inflation factors to arrive at a 2026 projected amount. Next, witness Kindschy recommended an adjustment of \$2,190,000, which is the inflated 2026 amount multiplied by 1/4, representing the last quarter of the test year that both units at Belle River will not be consuming coal. Finally, witness Kindschy recommended an additional adjustment which is to allow for recovery of half of the remaining expenses after subtraction of 1/4, resulting in an additional reduction of \$3,280,000. (5 TR 5098-5099; S-15.2 p. 2.)

The total reduction for Belle River fuel handling recommended by witness Kindschy is the sum of these two amounts and is \$5,470,000. (5 TR 5097-5099.)

In rebuttal, Company witness Guillaumin disagreed with Staff's adjustment to Belle River fuel handling, stating that the Company already included a 25% reduction to the labor portion of Belle River fuel handling in its initial filing. (3 TR 671.) DTE Electric asserts that it included a 25% reduction to Belle River fuel handling in its original filing, despite being asked several times both in a discovery and an audit request if the Company made any reductions to Belle River fuel handling. (S-15.2, pp. 3-4.) Company witness Guillaumin states that the Company already included a reduction of \$1.95 million for Belle River fuel handling. (3 TR 671.) Assuming the record supports that the Company made that adjustment, Staff is now recommending a reduction of \$3.52 million for Belle River fuel handling, which is Staff's original adjustment of \$5.47 million less \$1.95 million that the Company states was included in the original filing.

Staff's seventh adjustment to Steam Power Generation O&M expenses is a reduction of \$4,372,000 to the Company's Periodic Outage Normalization adjustment. (Appendix C, Line 18.) Staff witness Kindschy testified that she has several concerns with the Company's periodic outage normalization in the historical test year as shown on Exhibit A-13, Schedule C5.1 under footnote 5. First, the historical years that DTE Electric used in its normalization include O&M expenses to maintain all four of the Monroe units through a later plant retirement date. Now that DTE Electric is planning to retire Monroe Units 3 and 4 in 2028, the historical

periodic outage expenses include amounts that will not be spent in the future.

Second, none of the Company's actual spending in previous years supports the level of forecasted periodic outage expenses in the projected test year. For example, DTE Electric's actual periodic outage spending in 2024, which includes reductions for the earlier retirement of Monroe Units 3-4, was \$17,498,655, while the projected amount for the 2026 test period is \$26,940,000. (5 TR 5100; S-15.3, p 4.)

Furthermore, the 2020-2022 historic periodic outage spending adjusted for CPI that the Company used for its normalization are all higher than the actual amount spent in 2024 that includes more recent spending and inflation. (5 TR 5100; S-15.1, p. 5; S-15.3, p. 4.)

Witness Kindschy testified that Staff's third issue with the calculation of the periodic outage normalization is that the Company presented a different calculation for its 2023 periodic outage normalization in its previous electric rate case. In response to a discovery request in MPSC Case No. U-21534, witness Kindschy testified that Staff obtained updated test year O&M projections that began with a 2023 historic test year. (5 TR 5101; S-15.3, pp. 5-6.) The Company calculated a periodic outage normalization adjustment of \$7,232,000 when beginning with a 2023 historic test year in Case No. U-21534. (S-15.3, p. 6.) However, in the current rate case when beginning with the same 2023 historic test year actual expenses, the periodic outage normalization for 2023 increases to \$11,604,000. (A-13, Schedule C5.1, under footnote 5.)

Witness Kindschy requested that the Company explain the differences to the historical adjustments to 2023 between what was provided in Case No. U-21534 and the current case, but the explanations did not resolve the inconsistencies. (5 TR 5101; S-15.3, p 1.) Witness Kindschy testified that she could not resolve why the historical adjustments to the same historical test year as the starting point for O&M expenses would vary both in the types of historical adjustments as well as the amounts. For all of these reasons, witness Kindschy testified that she did not find the periodic outage normalization presented by the Company reasonable. (5 TR 5101.)

Staff witness Kindschy explained that the Company calculated the periodic outage normalization using the same 2023 historical test year in Case No. U-21534 to be \$7,232,000. Witness Kindschy noted that the difference between the actual 2024 and 2023 periodic outage spending was \$7,668,108, and this amount is closer to the amount that DTE Electric calculated in its previous rate case using the same adjusted 2023 historic test year as its starting point. (5 TR 5101; S-15.3, p. 6.)

From this information, witness Kindschy determined that the periodic outage normalization that the Company presented in its previous rate case for the same 2023 historical test year is more reasonable than the one in the current rate case. The difference between \$7,232,000 and the Company's periodic outage normalization under footnote 5 of \$11,604,000 results in a reduction of \$4,372,000. (5 TR 5101-5102.) Staff recommends that the Commission and ALJ adopt Staff's

\$4,372,000 reduction to DTE Electric's periodic outage normalization adjustment to the historical test year.

In rebuttal, Company witness Guillaumin disagrees with Staff's reduction to the periodic outage adjustment in the historical test year, stating that the Company's proposed periodic outage spending in 2026 is already \$3 million less than what it anticipates spending in 2026. (3 TR 676-677.) While Staff can appreciate that the Company believes, and possibly wants, to spend \$26 million on periodic outages in the 2026 test year, Staff is charged with setting reasonable rates. And Staff's position is that the Company has not shown that it in fact will spend that level of O&M on periodic outages based on all previous spending. (5 TR 5100, S-15.3, pp. 3-4.) Furthermore, as the Company's coal fleet continues to shrink with the expected retirement of Monroe Units 3 and 4 in 2028, periodic outage spending should be decreasing over time, not increasing. Similar to Staff's concern with one-time O&M projects being included in the projected test period if rates are in effect for more than one year, a higher level of periodic outage O&M if included in the projected test period may not be incurred if rates are in effect for more than one year. For all of these reasons, Staff recommends that the Commission and the ALJ adopt Staff's \$4,372,000 reduction to the Company's periodic outage normalization to the historic test year.

Staff's eighth adjustment is a reduction based on the application of Staff's inflation rates. (Appendix C, Line 19.) Staff witness Joseph E. Ufolla testified to different inflation rates than the Company that Staff used in the development of its

case. (5 TR 4954.) Using Staff's recommended inflation rates, Staff witness Kindschy testified that Steam Power Generation O&M expense should be reduced by \$2,039,000. (5 TR 5105-5106; S-15.6, p. 1.) Staff recommends that the Commission and the ALJ adopt Staff's \$2,039,000 reduction to Steam Power Generation O&M expenses for Staff's inflation rates.

**iii. Staff recommends reducing Fuel Supply & MERC Fuel Handling O&M expense by \$92 thousand. (Appendix C, Line 22.)**

Staff recommends reducing Fuel Supply & MERC Fuel Handling O&M expense by \$92 thousand. Staff witness Joseph E. Ufolla testified to different inflation rates than the Company that Staff used in the development of its case. (5 TR 4954.) Using Staff's recommended inflation rates, Staff witness Kindschy testified that Fuel Supply & MERC Fuel Handling O&M expense should be reduced by \$92,000. (5 TR 5105-5106; S-15.6, p. 2.) Staff recommends that the Commission and the ALJ adopt Staff's \$92,000 reduction to Fuel Supply & MERC Fuel Handling O&M expenses for Staff's inflation rates.

**iv. Staff recommends reducing Nuclear Power Generation O&M expense by \$1.354 million. (Appendix C, Line 25.)**

Staff recommends reducing Nuclear Power Generation O&M expense by \$1.354 million. (Appendix C, Line 25.) Staff witness Joseph E. Ufolla testified to different inflation rates than the Company that Staff used in the development of its case. (5 TR 4954.) Using Staff's recommended inflation rates, Staff witness

Kindschy testified that Nuclear Power Generation O&M expense should be reduced by \$1.354 million. (5 TR 5105-5106; S-15.6, p. 3.) Staff recommends that the Commission and the ALJ adopt Staff's \$1.354 million reduction to Nuclear Power Generation O&M expenses for Staff's inflation rates.

**v. Staff recommends reducing Hydraulic Power Generation O&M expense by \$131 thousand. (Appendix C, Line 28.)**

Staff recommends reducing Other Power Generation O&M expense by \$131 thousand. (Appendix C, Line 28.) Staff witness Joseph E. Ufolla testified to different inflation rates than the Company that Staff used in the development of its case. (5 TR 4954.) Using Staff's recommended inflation rates, Staff witness Kindschy testified that Hydraulic Power Generation O&M expense should be reduced by \$131,000. (5 TR 5105-5106; S-15.6 p. 4.) Staff recommends that the Commission and the ALJ adopt Staff's \$131,000 reduction to Nuclear Power Generation O&M expenses for Staff's inflation rates.

**vi. Staff recommends reducing Other Power Generation O&M expense by \$5.512 million. (Appendix C, Line 30-33.)**

**[References in the Record:** Guillaumin, 3 TR 659-661, A-13 Schedule C5.5; Kindschy, 5 TR 5102-5106, S-15.4-15.6.]

Staff recommends reducing Other Power Generation O&M expense by \$5.512 million. (Appendix C, Line 30-33.) Staff recommends three adjustments to Other Power Generation O&M expenses.

Staff's first adjustment to Other Power Generation is a reduction of (\$917,472) for the Trenton Channel Battery Energy Storage System (BESS). (Appendix C, Line 31.) Company witness Margaret E. Guillaumin explained that the BESS operation adjustment on Exhibit A-13 Schedule C5.5 under footnote 4 included expenses for the Slocum BESS that went into service in February 2025 and also included some expenses for the Trenton Channel BESS that is projected to reach commercial operation in 2026 with no month specified. (3 TR 660.) Staff witness Kindschy testified that supporting information received through discovery stated that the commercial operation date (COD) for the Trenton Channel BESS will be at the end of 2026. (5 TR 5102-5103, S-15.4 p. 3.) Witness Kindschy also explained that this information showed that DTE Electric included the equivalent of a half year of O&M expenses for several categories of expenses related to the Trenton Channel BESS that total \$914,472. (5 TR 5102-5103.) Subsequent discovery responses confirmed that DTE Electric continues to expect the COD of the Trenton Channel BESS to be in December 2026. (5 TR 5103; S-15.4 p. 7.) With only the month specified, witness Kindschy determined that the COD for the Trenton Channel BESS would be beyond the test period, and therefore, it is not reasonable to include any O&M expenses. For this reason, Staff recommends that the Commission and the ALJ remove all O&M expenses for the Trenton Channel BESS which is reduction of \$914,472. The Company did not file rebuttal testimony on Staff's recommended reduction to the Trenton Channel BESS O&M expenses.

Staff's second adjustment to Other Power Generation O&M expenses is a reduction for Peaker Increased Maintenance. Appendix C, Line 32.) Witness Kindschy requested additional information for the increase to the test period for Peaker Increased Maintenance as well as if the projects that encompassed this adjustment were one-time or annual expenses. (5 TR 5103, S-15.4, p. 1 and p. 4.) In response, the Company stated that the Peaker Increased Maintenance category of projects are all either one-time projects or expected to occur at varied intervals that were not specified as annual. (5 TR 5104; S-15.5.) For the same reasons previously discussed for Steam Power Generation O&M projects in section V.A.2.i, Witness Kindschy determined that a reasonable time period for recovery of one-time and infrequent O&M projects is two years and therefore recommended that Peaker Increased Maintenance O&M expenses be reduced by half. As previously noted, if the frequency of rate cases changes, witness Kindschy stated it may be appropriate for the Commission and ALJ to spread one-time and infrequent expenses over a longer period, such as 3 years or more. (5 TR 5104.) Staff recommends that the Commission and the ALJ reduce the Company's Peaker Increased Maintenance O&M expenses by \$4,302,500.

Staff's third adjustment is a reduction of (\$295,000) for the application of Staff's inflation rates. (Appendix C, Line 33.) Staff witness Joseph E. Ufolla testified to different inflation rates than the Company that Staff used in the development of its case. (5 TR 4954.) Using Staff's recommended inflation rates, Staff witness Kindschy testified that Other Power Generation O&M expense be

reduced by \$295 thousand. (5 TR 5105-5106; S-15.6 p. 5.) Staff recommends that the Commission and the ALJ adopt Staff's \$295,000 reduction to Other Power Generation O&M expenses for Staff's inflation rates.

**vii. Staff recommends reducing Distribution O&M expense by \$3.223 million. (Appendix C, Line 33)**

**[References in the Record:** Staff witness Shannon M. Rueckert, S-24.5, (Amended) 5 TR 5195. Company witness Bruzzano, 3 TR 995.]

Staff recommends reducing Distribution O&M Expense by \$3,223,000.

(Appendix C, Column G, Line 36.) Staff witness Rueckert supports utilizing the inflation factors developed and supported by Staff witness Ufolla of 2.73% for 2025 and 2.66% for 2026. The Company used bifurcated inflation rates that contain a wage component the Company is partially in control of. The Commission has historically rejected use of this "blended rate" in prior general rate cases. Staff recommended utilizing the inflation factors developed and supported by Staff witness Ufolla of 2.73% for 2025 and 2.66% for 2026 shown on Exhibit S-24.5. Staff witness Rueckert noted the Company's composite inflation rate contains a wage component the Company is partially in control of. (5 TR 5195.)

Company witness Bruzzano rebutted Staff's rejection of composite inflation rates. Witness Bruzzano cited Collective bargaining agreements obligated to increase pay rates by 3% annually. However, the Company did not include offsetting reductions to O&M based on efficiency gains that accompany experience. (3 TR 995.)

Staff recommends that the Commission approve a total Distribution expense projection of \$502,290,000 using Staff's inflation rates supported by witness Ufolla. This is a downward adjustment of \$3,223,000 from the Company's request of \$505,513,000.

**viii. Staff recommends reducing Uncollectibles O&M expense by \$1.561 million. (Appendix C, Line 38-40)**

**[References in the Record:** Staff witness Shannon M. Rueckert, 5 TR 5192, S-24.1, S-6, Schedule F2.]

Staff recommends reducing Uncollectibles O&M expense by \$1.561 million. (Appendix C, Column g, Line 39-40.) This is composed of two adjustments described below.

The first adjustment is for \$947 thousand reduction for payment stability plan sponsored by Staff witness Rueckert. (Appendix C, Line 39.) Staff proposed several updates to the Company's UCX projection. Staff witness Rueckert requested the Company update its projection to include 2024 expenses, as shown on Exhibit S-24.1. Although the Company used Staff's preferred direct write-off method, it applied an excessive revenue figure to calculate uncollectible expense via the Bad Debt Loss Ratio (BDLR). Staff recommends using the present revenue figure from Staff Exhibit S-6, Schedule F2, supported by witness Isakson. Staff Exhibit S-24.1 reflects this revenue adjustment in its projection.

The second is a \$614 thousand reduction for uncollectible expense sponsored by Staff witness Braunschweig. (Appendix C, Line 40.) Staff witness Braunschweig

supports disallowing the Low-Income Payment Stability Plan Pilot Amortization Expense (line 15).<sup>7</sup> Staff witness Revere supports using the PSCR Factor revenue (line 21) of Staff Exhibit S-24.1. (5 TR 5192.) Staff recommends the Commission approve a UCX expense projection of \$46,469,000. This is a downward adjustment of \$1,561,000 from the Company's request of \$48,030,000.

**ix. The power supply sales determinant forecast approved by the Commission should be used to calculate the uncollectibles expense (UCX) adjustment proposed by the Company.**

**[References in the record:** Staff witness Nicholas M. Revere, 5 TR 5303-5305; Company witness Jason Sparks, 4 TR 2737-2738; Company witness Aaron Willis, 4 TR 1775-1778; Company witness Shawn L. Burgdorff, 4 TR 2077-2078.]

While Staff does not oppose the Company's newly-proposed UCX adjustment related to power supply cost recovery (PSCR) factor revenues, as discussed elsewhere in this brief, Staff witness Nicholas M. Revere recommended using a different sales forecast than that utilized by the Company in its initial filing. (5 TR 5303-5304.) The Company does not object to Staff's proposal regarding the sales forecast, for the reasons outlined below. (4 TR 1775.)

As described by Staff witness Revere, the Company's calculation relied on the net system requirement (with volumes associated with D8 buythrough, third-party sales, and R10 removed) projection from the Company's filing in MPSC Case No. U-

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<sup>7</sup> This revenue-neutral adjustment is detailed and supported in section V(a) of this initial brief and reflects a reallocation of recording PSP expenses instead of a disallowance of the expense.

21594 (the Company's 2025 PSCR plan case) multiplied by the unit cost from the same case which incorporates the base unit cost and the unit cost above the base (PSCR factor), which is not included in the proposed PSCR base amount in the instant case. (5 TR 5303, referencing Company witness Sparks, 4 TR 2737-2738.) Staff Witness Revere did not take a position on the inclusion of estimated PSCR factor revenue in the UCX projection, and did not take issue with the PSCR factor projection method for purposes of the instant case. (5 TR 5305.) However, Staff witness Revere recommended using the projected power supply sales (with the same volumes removed as in the Company's proposal) from the instant case rather than the net system requirements from the PSCR case, stating power supply sales from the instant case are "a more appropriate basis for projecting PSCR factor revenue over the test period than that proposed by the Company" as they match the Company's forecast in the instant case while the PSCR net system requirements do not. (5 TR 5304.) Company witness Aaron Willis stated the Company's non-objection to Staff witness Revere's proposal. (4 TR 1775.) For these reasons, Staff's proposal to use the power supply sales from the instant case in the calculation of the projected PSCR revenue included in the UCX calculation should be approved.

Should the Commission approve the inclusion of projected PSCR revenue in the UCX calculation (which Staff did not oppose), it should be updated for any changes to sales approved by the Commission.

- x. **The Company should continue examining its PSCR factor to ensure that costs are properly allocated in rate cases.**

Staff witness Revere recommended in direct testimony that the Commission require the Company to reset its PSCR base in its next rate case, for several reasons: first, it would obviate the need for the PSCR factor revenue estimation the Company proposed to include in the instant case, discussed elsewhere in this brief; second, and more importantly, a reset would ensure costs are appropriately allocated to the classes, as the implicit allocation of these costs through the PSCR factor differs from the explicit allocation that occurs in a rate case such as the instant case. (5 TR 5304-5305.) Company witness Willis opposes the recommendation, claiming that, outside of the COVID times and “energy market upheaval in response to geopolitical events”, that “the billed factor has consistently remained within a relatively narrow band around zero,” illustrating with a graph. (4 TR 1776-1777.) Staff notes that, based on the graph presented, the PSCR factor does not appear to have returned to the “relatively narrow band around zero” since the disruptions mentioned by Company witness Willis, and has instead remained elevated. However, Staff admits it is possible that the factor may yet return to that band, and waiting for more information may be prudent. Company witness Willis also notes that, as the PSCR allocation is relatively weighted towards energy, the allocation impact may not be very significant. (4 TR 1777-1778.) Staff posits that 1% of PSCR costs is not an insignificant amount of costs, and the Company did not present the impact of the differing allocations, so the overall impact is not clear on the record. Company witness Shawn L. Burgdorf also responds to Staff’s recommendation, claiming the amount of work that would be required to implement

the recommendation is significant. (4 TR 2077-2078.) Staff does not necessarily agree the work would be as substantial as claimed by Company witness Burgdorf (see description at 5 TR 5305.) Company witness Willis also implies that Staff's proposal is mainly for the purpose of improving the UCX calculation. (4 TR 1776.) As discussed above, this is one goal, but not the main or most important reason for Staff's proposal. However, in order to see if future data bears out the Company's implicit claim that the PSCR factor will return to hovering around zero in the future, Staff retracts its recommendation that the Company be required to propose resetting its PSCR base in its next rate case for the purposes of the instant case.

Staff recommends the Company continue examining the amount of PSCR costs flowing through the PSCR factor to determine whether the PSCR factor returns to historical trends or not, and Staff reserves the right to present a similar proposal in future cases should the data support it.

**xi. Staff recommends reducing Regulated Marketing O&M expense by \$544 thousand.**

Staff recommends reducing Regulated Marketing O&M expense by \$544 thousand. (Appendix C, Column g, Line 43-44.) This is composed of two adjustments described below.

**xii. The Commission and ALJ should adopt Staff's recommendation to disallow \$300,000 for the support of a demand response (DR) call center. (Appendix C, Line 43)**

**[References in the Record:** Towslee 5 TR 5157-5163, S-20.1; Leuker 3 TR 1363, 1379-1381.]

Staff witness Joshua S. Towslee summarized Staff's position regarding DTE's DR-specific call center. Staff recommends disallowance of the projected costs to support this call center. (5 TR 5160-5161.)

In its filing, the Company requests approval for costs of its "Pilots and Other Projects" category, in which a dedicated call center to specifically handle customer calls related to DR is included. (3 TR 1363.) The Company projects annual O&M expenses of \$300,000 to support this call center. (S-20.1, p 5.)

Witness Towslee explains the Company failed to provide sufficient support to justify this cost. (5 TR 5160-5161.) In response to Staff's discovery request, the Company stated it does not track the number of DR-related calls it receives through its general call center, and the Company did not respond to questions about recent trends regarding the volume of DR-related call it receives. Additionally, the Company failed to identify the existence of any problems or deficiencies that the DR call center is intended to address. (S-20.1, pp. 3, 5.) Because of this lack of information about DR-related call volume, any realized or anticipated trends related to DR calls, or a stated problem which the DR call center is intended to remedy, Staff cannot find the cost prudent.

In rebuttal, Company Witness Leuker refutes Witness Towslee's assertion that the Company had not previously sought approval of the call center, stating that it was included in the \$1.27M requested for "Other DR Projects" in the Company's previous electric rate case, Case No. U-21534. Witness Leuker also explains in

rebuttal that through the DR call center, “(DR) calls can be resolved more quickly, which reduces the number of escalations to program managers, improving first call resolution metrics.” (3 TR 1380.) Because of this, the Company claims the overall DR customer experience is enhanced, resulting in greater customer retention for its DR programs. Witness Leuker includes in rebuttal that the dedicated call center received through July 2025 6,594 direct calls, with another 2,530 calls transferred from the general call center. Finally, Witness Leuker asserts that the Company anticipates future growth for residential DR and the forecasted spend should be approved to ensure the Company can deliver a positive experience to customers. (3 TR 1379-1381.)

Staff acknowledges the call center was included in a broad category of expenses approved in the prior case, though specific amounts for the call center were not identified therein. Staff appreciates the DR call volume information included in Witness Leuker’s rebuttal, but the absence of data for baseline comparison remains, as does the lack of support for the Company’s implication that these calls cannot sufficiently be handled by DTE’s general call center. Because the Company has not yet adequately supported the proposed expense, Staff cannot determine the necessity or prudence of the call center and stands by its recommended disallowance.

**xiii. The Commission and ALJ should adopt Staff’s recommendation to defer decisions about changes to the DR regulatory construct.**

**[References in the record: Towslee 5 TR 5157-5163]**

Staff Witness Towslee provides Staff's response to DTE's suggestions regarding changes to the current three-phase approach for handling DR. Staff recommends consideration of the regulatory construct be handled exclusively in MPSC Case No. U-21637, In the matter, on the Commission's own motion, to investigate opportunities for improving the process by which it reviews applications filed under MCL 460.6a, which is currently before the Commission. (Towslee 5 TR 5160-5163.) This issue was not addressed in rebuttal.

In Case No. U-21637, the Commission sought several rounds of comment on multiple topics, one of which is potential changes to the current DR framework. Comment periods in that case are currently closed, and the case is pending. Staff maintains the assertion that MPSC Case. No. U-21637 is the appropriate venue for consideration of this topic.

**xiv. Staff recommends reducing Regulated Marketing O&M expense by \$244 thousand for inflation (McMillan-Sepkoski).**

**[References in the record:** Staff witness Robert F. Nichols, II, CPA, Appendix C, Col. g, Lines 43-45; Company Witness Foley 4 TR 2653, A-13, Schedule C5.9; Staff witness Ufolla, 4 TR 4954, S-4 D-3a; Staff witness McMillan-Sepkoski 5 TR 4984, S-9.4]

In its initial filing, the Company proposed that the Commission include a \$32,097,000 for regulated marketing O&M expense in the revenue requirement. (4 TR 2653.)

Staff witness Theresa McMillan-Sepkoski's recommended disallowance resulting in a decrease to the Company's projected marketing O&M expense was made by updating the Company's Exhibit A-13, Schedule C5.9 with Staff witness Ufolla's inflation percentages and projecting forward to the test year. (5 TR 4984; S-9.4.) Staff recommends that the Commission approve a reduction of \$244,000 for inflation for regulated marketing O&M expense for the projected test year.

**xv. Staff recommends reducing Corporate Support O&M expense by \$72.757 million.**

**[References in the Record:** Staff witness Nichols, Appendix C, Column g, Line 47; Company witness Fix 3 TR 1482; Company Witness Uzenski 4 TR 2474; Staff witness McMillan-Sepkoski 5 TR 4982, S-9.1; DTE Electric Rate Case, MPSC Case No. U-21534, 1/23/25 Order, pp. 278-279; AG Witness Coppola 4 TR 3562; ABATE Witness York 4 TR 3250-3251.]

Staff recommends reducing Corporate Support O&M expense by \$72.757 million. (Appendix C, Column g, Lines 47-57.) This is composed of eleven adjustments described below.

**Staff recommends reducing Incentive Compensation O&M expense by \$35.838 million. (Appendix C, Line 47.)**

Staff witness Theresa McMillan-Sepkoski recommends reducing Incentive Compensation O&M expense by \$35.838 million. (Appendix C, Line 47.) In its initial filing, the Company proposed that the Commission include a \$56,369,000 incentive compensation O&M expense in the revenue requirement. (3 TR 1482) However, portions of this expense should be disallowed by the Commission as compensation tied to the Company's financial metrics.

Staff's recommended disallowance is the portion of the Company's employee incentive compensation plan (EICP) expense that is tied to achieving financial metrics. (5 TR 4982; S-9.1.)

The Company has incentive compensation programs that are, in part, based on achieving financial metrics. Staff does not dispute the overall reasonableness of employee compensation but instead argues that there should be a distinction on who pays based on the metrics included. For example, ratepayers benefit from operational metrics that promote reliability and safety. Stockholders benefit from financial metrics based on earnings per share and operating cash flow. The Commission has long held that shareholders, not ratepayers, must pay for incentives related to increasing profits, and no party has given a reason for the Commission to reverse that stance. (5 TR 4980-4982.)

Staff's recommendation to the Commission is based on the Commission's Order in Case No. U-21534. In that case, the Commission disallowed employee incentive compensation tied to financial measures. *In re DTE Electric Rate Case*, MPSC Case No. U-21534, 1/23/25 Order, p. 278. This is consistent with prior Commission orders finding that when incentive compensation plans are tied to Company earnings and cash flow, the plans largely benefit shareholders. (*Id.*) Applying the same reasoning to the instant case, Staff aligned the cost of financial performance measures within the incentive compensation plan to the group that benefits from those financial performance measures-shareholders.

The Attorney General (AG) recommends that the Commission disallow \$35.8 million of the financial metrics portion of incentive compensation and only approve 49.4% of the remaining \$20,531,000 or \$10,142,000 of the incentive compensation tied to operational metrics for a total disallowance of \$46,277,000. (4 TR 3562.)

ABATE recommends that the Commission disallow \$35,838,000 of incentive compensation related to financial measures (4 TR 3250.) and disallow \$9.33 million of incentive compensation related to operational measures. (4 TR 3251.)

Staff recommends to the ALJ and Commission to disallow the modification to the incentive compensation deferral mechanism that has again been proposed by the Company. (4 TR 2474.)

The Company proposed that the mechanism should include payout amounts above 100% of target. (4 TR 2474.) As previously stated, the Commission has repeatedly disallowed the financial portion of incentive compensation for recovery in rates, and the level of payout approved by the Commission for operational measures has been at 100% of target level. In MPSC Case No. U-21297, Commission Order dated December 1, 2023, p. 239, and in MPSC Case No. U-21534, Commission Order dated January 23, 2025, the Commission approved the Company to use deferral treatment on actual incentive payout amounts for operational metrics achieved, up to 100% of target level.

For the reasons presented above, Staff urges the ALJ and Commission to remove \$35,838,000 from the Company's proposed O&M EICP expense. This is the portion tied to achieving financial metrics. Excluding these expenses is reasonable

and consistent with Commission precedent. For the proposed modification to the incentive compensation deferral mechanism, the Company did not address Staff's recommendations in rebuttal, therefore Staff assumes the Company is in agreement. For the reasons presented above, Staff urges the ALJ and Commission to disallow the proposal by the Company for the modification to the incentive compensation deferral mechanism.

**Staff recommends reducing Restricted Stock O&M expense by \$7.730 million. (Appendix C, Line 48.)**

[References in the record: Staff witness Nichols, Appendix C, Line 48; Company Witness Fix 3 TR 1497; Staff witness McMillan-Sepkoski, 5 TR 4984; S-9.2, p. 4.]

Staff witness Theresa McMillan-Sepkoski recommends reducing Restricted Stock O&M expense by \$7,730,000. (Appendix C, Line 48.) The value of the awards granted is dependent on the DTE Energy Company stock price. According to Company witness Fix, "...the cost to the Company is recognized at the value of those shares on the date of grant..." (3 TR 1497.) The booklet provided as Exhibit S-9.2, pp. 4, explains that these awards "provide greater value when the stock price increases and dividends are authorized by the Company." Therefore, restricted stock rewards [recipients] for sustaining the Company's profitable growth, and link [recipients] rewards to long-term financial results. (Exhibit S-9.2.)

As the Company's Restricted Stock awards are tied to sustaining profitable growth, and rewarding financial results, excluding this expense would be consistent with the Commission's long-standing position of disallowing compensation expenses related to financial metrics.

**The Commission should disallow the \$283,000 in O&M expenses associated with the Communication Compliance and Data Loss Prevention (DLP) Diversification project. (Appendix C, Line 49.)**

As addressed in section 1.A, the Commission should disallow the O&M expense associated with the Communication Compliance and Data Loss Prevention (DLP) Diversification project because the Company failed to provide information to support the need for this project at this time. (5 TR 5133.) Through audit the Company did not report any issues with the current system. (S-18.0; pp. 1-3.) In rebuttal the Company provided the same information Staff already had received through audit response and included some new information. The Company addressed multiple different areas, some new and some installed within the last year or longer, as part of this project. Staff is confused about what specific applications the Company plans on expanded coverage to, and why it must be done now. The Company shared coverage issues with security barriers and staying in compliance but did not elaborate more. (4 TR 2356-2357.) The Company did not provide sufficient detailed information to support the immediate need for this project in its rebuttal. Staff does not see the immediate need to address the security gaps and compliance if the Company has gone 12 to 18 months with the new applications, and likely longer with the cloud solutions, without doing anything, if it was a pressing issue the Company would not have waited. Additionally, the Company did not include information in audit or rebuttal as to any changes that have warranted the need to address these two concerns now. The Commission should disallow the \$283,000 in O&M expenses associated with this project.

**Staff recommends reducing Customer Insight Application Health O&M expense by \$100 thousand. (Appendix C, Line 50.)**

Staff recommends reducing customer insight platform application health O&M expense by \$100 thousand. (Appendix C, Line 50.) Consistent with the above discussion regarding the recommended disallowance for capital expenditures for the customer insight platform application health project, Staff recommends disallowance of the requested O&M costs for this project for the test year, resulting in a proposed disallowance of \$100,000.

**Staff recommends reducing Customer Relationship and Billing O&M expense by \$2.695 million. (Appendix C, Line 51.)**

Staff recommends reducing customer relationship and billing O&M expense by \$2.695 million. (Appendix C, Line 51.) Consistent with the above discussion regarding the recommended disallowance for capital expenditures for the customer relationship and billing project, Staff recommends disallowance of the requested O&M costs for this project for the test year, resulting in a proposed disallowance of \$2.695 million.

**Staff recommends reducing DTE Mobile App Application Health O&M expense by \$170 thousand. (Appendix C, Line 52.)**

Staff recommends reducing DTE mobile app application health O&M expense by \$170 thousand. (Appendix C, Line 52.) Consistent with the above discussion regarding the recommended disallowance for capital expenditures for the DTE mobile app application health project, Staff recommends disallowance of the requested O&M costs for this project for the test year, resulting in a proposed disallowance of \$170,000.

**Staff recommends reducing Outage WISMO and Map Sustainment O&M expense by \$249 thousand. (Appendix C, Line 53.)**

Staff recommends reducing outage WISMO, PPS and map application health O&M expense by \$249 thousand. (Appendix C, Line 53.) Consistent with the above discussion regarding the recommended disallowances for capital expenditures for the outage WISMO, PPS and map application health project, Staff recommends disallowance of the requested O&M costs for this project for the test year, resulting in a proposed disallowance of \$249,000.

**Staff recommends reducing Outage WISMO, PPS, and Map Enhancement O&M expense by \$525 thousand. (Appendix C, Line 54.)**

Staff recommends reducing outage WISMO, PPS, and map enhancement O&M expense by \$525 thousand. (Appendix C, Line 54.) Consistent with the previously discussed recommended disallowance for capital expenditures for the outage WISMO, PPS and map enhancement project, Staff recommends disallowance of the requested O&M costs for this project for the test year, resulting in a proposed disallowance of \$525,000.

**Staff recommends reducing Projects with level 2 cost estimates O&M expense by \$16 thousand. (Appendix C, Line 55.)**

The ALJ and the Commission should disallow \$16,000 in O&M expenses associated with IT projects with Level 2 cost estimates. Level 2 cost estimates are given to an investment more than a year, sometimes more than two years, prior to implementation. They are immature and imprecise. Please also see Section III.B.4., which addresses capital expenditure disallowances in detail.

**Staff recommends reducing Projects with level 3 cost estimates O&M expense by \$2.086 million. (Appendix C, Line 56.)**

The ALJ and the Commission should disallow \$2.086 million in O&M expenses associated with IT projects with Level 3 cost estimates. This O&M recommended disallowance is updated from Staff's testimony in which a reduction of \$2.488 was recommended. (Rogers, 5 TR 5056, Lines 16-19.) The original adjustment included costs also included for disallowance under Staff's individual IT project recommendation. Removing those amounts from the 10% Level 3 cost estimate disallowance updates Staff's recommended O&M disallowance to \$2.086 million. (A-44 JJ1, p. 13)

Level 3 cost estimates are inaccurate in nature and incomplete in the overall process of project development to implementation. This recommendation is consistent with Staff's recommended Level 3 cost estimate capital expenditure disallowance. Please see Section III.B.4 for corresponding capital expenditure disallowances, as testified to by Staff witness Rogers.

**Staff recommends reducing Corporate Support and Inflation O&M expense by \$23.065 million. (Appendix C, Line 57.)**

[References in the record: Staff witness Shannon M. Rueckert, S-24.2, 5 TR 5192; Company witness Bruzzano, 3 TR 995, A-13, Schedule C5.10.]

Staff recommends reducing Administrative & General Expenses (corporate support and inflation) by \$23,065,000. (Appendix C, Line 57.) Administrative & General Expenses are shown in Company Exhibit A-13, Schedule C5.10, supported by Witness Uzenski projections for accounts 920 through 931. The Company applied a composite inflation rate based on labor and non-labor factors. These rates are 3.5% for 2024, 3% for 2025, and 3.1% 2026. Staff requested the Company

update its historic base year to 2024, eliminating the need for the Company to adjust its base year higher than actual expenses. The Commission has historically rejected use of this “blended rate” in prior general rate cases. (5 TR 5192.)

Company Witness Bruzzano rebutted Staff’s rejection of composite inflation rates. Witness Bruzzano cited Collective bargaining agreements obligated to increase pay rates by 3% annually. However, the Company did not include offsetting reductions to O&M based on efficiency gains that accompany experience. (3 TR 995.)

Staff recommends utilizing the inflation factors developed and supported by Staff witness Joseph Ufolla of 2.73% for 2025 and 2.66% for 2026. Staff witness Rueckert noted the Company’s composite inflation rate contains a wage component the Company is partially in control of. Staff recommends that the Commission approve a total Administrative & General expense projection of \$200,995,000 based on the most current information available to the Company and Staff’s inflation rates supported by Witness Ufolla. This is a downward adjustment of \$23,065,000 from the Company’s request of \$224,060,000.

**xvi. Staff recommends reducing Pension and Benefits O&M expense by 7.136 million.**

**[References in the Record:** Staff witness Shannon M. Rueckert, S-24.4, 5 TR 5194. Company witness Cooper, 3 TR 1565.]

Staff recommends reducing Pension and Benefits O&M expense by \$7.136 million. (Appendix C, Column g, Line 59.) Staff recommends reducing total account 926 Employee pensions and benefits expenses by \$7,136,000. (Appendix C,

lines 59.) The Company's applied an "Average True Up" adjustment to increase its historic test year basis of VEBA expense increasing the 2023 basis and obfuscating two consecutive years of decline. Then applied a growth rate that is above what the Company has experienced. Staff Witness Rueckert applied a five-year average annual growth rate to the Company's undusted 2024 expense producing a fair and reasonable projection. (5 TR 5194.) The Company rebutted Staff and the AG's use of an unadjusted 2024 VEBA expense basis.

Witness Cooper argued that increasing the Company's historic basis by an average annual True Amount is necessary. (3 TR 1565.) However, applying the "Average True Up" to 2024 increases the basis unreasonably higher than the prior three years of actual expenses.

Staff witness Rueckert used the same method of projection for the Company's Employee Savings Plan (ESP) and Other Benefits components of account 926 expenses applying a five-year average annual growth rate to the Company's undusted 2024 expense producing a fair and reasonable projection. Staff Exhibit S-24.4 shows that using an unadjusted 2024 basis for all components is fair and reasonable when compared to historic expense levels. The 2024 basis for all components is not unreasonably low as portrayed by the Company. (5 TR 5194.) Therefore, Staff recommends a total account 926 expense projection of \$60,679,000. This is a reduction of \$7,136,000 to the Company's projection of \$67,815,000.

- c. Staff recommends a depreciation and amortization expense of \$1.331 billion.**

**[References in the Record:** Staff witness Hecht, 5 TR 4888-4889, S-3, Schedule C1.1, A-13, Schedule C1, A-13, Schedule C6, C; Company witness Vangilder, 3 TR 1603-1606, A-56, Schedule XX1.]

In its initial filing, DTE projected that its depreciation and amortization expense would be \$1.360 billion. Staff's depreciation expense of \$1.331 billion is \$28.453 million less than the Company's projection. (Appendix C, Column h, Lines 1, 66 and 67.) Staff's depreciation and amortization expense is less than the Company's because of the impact of Staff's capital expenditure disallowances on depreciation expense. See Section III.B. for Staff's capital expenditure disallowances.

In Staff's testimony, Staff witness Hecht proposed a reduction to depreciation expense as a corresponding adjustment from the capital expenditure reductions. (5 TR 4888-4889.) In the Company's rebuttal testimony, Company witness Vangilder pointed out several inaccurate calculations used by Staff to calculate the net rate base and depreciation expense adjustment that were inconsistent with the methodology the Company utilized to calculate depreciation expense in this case. (3 TR 1603-1606.)

Staff's brief takes into consideration the Company's concerns and has updated the corresponding impacts to net rate base and depreciation expense from Staff's capital expenditure adjustments accordingly. (Appendix E, Column f.) Based on the record evidence in this case, and Staff's agreement to the Company's rebuttal on this matter, Staff recommends the ALJ and the Commission adopt its adjustments to reduce depreciation expense by \$28.453 million.

Staff recommends property tax expense of \$344.320 million.

**[References in the Record:** Staff witness Hecht, 5TR 4889-4890, S-16.0, S-3, Schedule C1.1, Company witness Wisniewski, 4 TR 3140, 4 TR 3152-3154, A-13, Schedule C1, A-13, Schedule C7, C7.1, Company witness Vangilder 3 TR 1603-1606, A-56, Schedule XX1]

Staff recommends property tax expense of \$344.320 million, which is \$3.698 million less than the company's projection. (Appendix C, Column i.) Staff's property tax expense is less than the Company's because of the impact of Staff's capital expenditure disallowances on depreciation expense. See Section B for Staff's capital expenditure disallowances.

In Staff's testimony, Staff witness Hecht proposed a reduction to property tax expense as a result of two adjustments. First, was a corresponding adjustment from Staff's capital expenditure reductions. (5 TR 4889.) This adjustment is discussed further below. Second, was an adjustment removing property tax expense from distribution plant capital expenditures classified as intangible plant that were included in the calculation of the Company's property tax expense for the test period. (5 TR 4889-4890.) The Company did not specifically address this adjustment in their rebuttal. Staff's brief maintains this adjustment.

In the Company's rebuttal testimony, Company witness Wisniewski pointed out elements of the methodology used by Staff to calculate the proposed property tax expense adjustment that were inconsistent with the methodology the Company utilized to calculate property tax expense in this case. (4 TR 3153-3154.)

Staff's brief takes into consideration the Company's concerns and has updated the corresponding impacts to property tax expense from Staff's capital expenditure adjustments accordingly. (Appendix E, Column g.)

Based on the record evidence in this case, and Staff's agreement to the Company's rebuttal on this matter, Staff recommends the ALJ and the Commission adopt its adjustments to reduce property tax expense by \$3.698 million.

**d. Staff recommends other tax expense of \$52.064 million.**

Staff recommends the ALJ and the Commission adopt the company's projected other tax expense of \$52.064 million. (Appendix C, Column j, Line 67.)

**e. Staff recommends state and local income tax expense of \$71.176 million.**

Staff recommends state and local income tax expense of \$71.176 million, which is \$9.639 million greater than the Company's projection of \$61.537 million. (Appendix C, Column k, Line 1, 66 and 67.) Staff's state and local income tax is different than the company's due to Staff's adjustments to the Company's projected revenues and expenses.

**f. Staff recommends federal income tax expense of \$139.943 million.**

Staff recommends federal income tax (FIT) expense of \$139.943 million, which is \$30.570 million greater than the company's projection of \$109.372 million. (Appendix C, Column l, Line 1, 66 and 67.) Staff's adjustments to the Company's projected revenues and expenses are responsible for the difference.

**g. Staff recommends adoption of the Company's projected other utility income of \$6.425 million. (Appendix C, Column m, Line 67.)**

Staff recommends the ALJ and the Commission adopt the company's projected other utility (income)/deductions of \$(6.425) million. (Appendix C, Column m, Line 67.)

**3. Staff recommends a total allowance for funds used during construction (AFUDC) of \$62.659 million.**

Staff recommends the ALJ and the Commission adopt the company's projected AFUDC of \$62.659 million. (Appendix C, Column p, Line 67.)

**4. Staff recommends loss on reacquired securities \$2.435 million.**

The Company projected Other Operating Income reduction of \$2.435 million for loss on reacquired securities. Staff recommends the ALJ and Commission adopt the Company's projection. (Appendix C, Column q, Line 67.)

**5. Staff recommends return on tree trim surge regulatory asset revenue requirement of \$4.854 million.**

[References in the Record: Staff witness Rueckert, S-24.6, 5 TR 5196.]

Staff recommends return on tree trim surge regulatory asset revenue requirement of \$4.854 million, which is \$7.062 million less than the company's projection of \$11.916 million. (Appendix A, Line 9; Appendix 1.1, Line 6.)

The Company used its Rate of Return on Permanent Capital of 9.45% supported by witness Vangilder. This produced a return on the Tree Trim regulatory asset of \$11,916,000 shown on Company Exhibit A-1 S-24.6, Schedule A1.1. The Company has not been approved to use the Rate of Return on Permanent

Capital. In its Order in case U-21297, the Commission stated that the “ALJ noted that the surge program is currently successful and recommended that the program should remain as is with interest at the short-term debt rate...” Consistent with the Commission’s Order in MPSC Case No. U-21297, Staff witness Rueckert used the short-term debt rate of 3.85% supported by Staff witness Ufolla. (5 TR 5196.) *In re DTE Electric’s 2023 Rate Case*, MPSC Case No. U-21297, 12/1/2023 Order, p. 280. Witness Rueckert’s original Exhibit S-24.63 contained an error. A cell reference outside of the print area was excluded. However, Staff’s filed revenue deficiency included the correct amount. The correct calculation is shown in Appendix A1.1. This creates a return on Tree Trim regulatory asset of \$4,854,000, a reduction of \$7,062,000 from the Company’s request of \$11,916,000.

**6. Staff recommends return on Monroe regulatory asset revenue requirement of \$139.817 million.**

Staff recommends return on Monroe regulatory asset revenue requirement of \$139.817 million, which is \$1.253 million less than the company’s projection of \$141.070 million. (Appendix A, Line 10; Appendix A1.2, Line 4.)

Staff’s Monroe regulatory asset – return on is \$1,253,000 less than the Company’s projection because Staff applied its 6.52% projected pre-tax cost of capital in lieu of the Company’s projected pre-tax cost of capital of 6.58% for the Monroe regulatory asset – return on. (5 TR 4880.) Both Staff and DTE’s pre-tax weighted average cost of capital applied to the Monroe regulatory asset are recalculated from the overall cost of capital using 9% ROE in accordance with the

MPSC's U-21193 order dated July 26, 2023. (5 TR 4880; A-14, Schedule D1; S-4, Schedule D1.) Staff recommends that the Monroe regulatory asset – return on should be recalculated based upon the cost of capital decisions made by the ALJ and the Commission. (*Id.*)

## **VI. COST OF SERVICE AND RATE DESIGN**

### **A. Electric Rate Design**

[**References in the Record:** Staff witness David Isakson, 5 TR 4904-4913, 5 TR 4920-4923; Company witness Christopher J. Hartley, 3 TR 1412, 1416, (Rebuttal), 3 TR 1452-1453; Company witness Anthony Turner, 4 TR 2597, 4 TR 2601-2608; Willis, 4 TR 1728-1735, 4 TR 1785-1789, 4 TR 1791; ABATE witness Brian C. Andrews 4 TR 3212-3220, 3229-3232; Kroger witness Justin Bieber, 4 TR 4445-4457; MNC<sup>8</sup> witness Douglas B. Jester 5 TR 4782-4786.]

### **B. The Commission should require the Company to develop an explicitly calculated discount for Rate D1.1 power supply rates that reflect their value as a demand response resource.**

Residential Rate D1.1 is the Company's interruptible space-conditioning rate that applies to separately metered air conditioning load. This rate differs from the standard residential service rate because Rate D1.1 has a reduced monthly service charge and a discounted power supply charge that does not vary by season or time-of-day. (5 TR 4909.) Rate D1.1 pays about half the amount per kWh than Rate D1.11 for on-peak summer usage, when air conditioning load is mostly likely to occur. (5 TR 4910.) The discounts afforded to Rate D1.1 are to reflect the

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<sup>8</sup> Michigan Environmental Council, Natural Resources Defense Council, and Citizens Utility Board of Michigan, is collectively identified as MNC.

interruptible nature of the service, and because service only requires an extra meter but not an additional service drop or other customer-related costs. (*Id.*)

All residential power supply rates are calculated by allocating the class's revenue requirement to each rate based on present revenue. (5 TR 4910.) This method is inappropriate for rate D1.1 because it is a demand response (DR) rate that provides a benefit to all power supply customers. The benefit of interrupting D1.1 customers' load during peak times can and should be quantified and used to determine an appropriate discount. (5 TR 4910-4911.) For example, Consumers Energy Company offers a similar interruptible air conditioning program but provides customers with a \$5 bill credit per summer month. This method quantifies how much interruptions are worth in offsetting power supply costs by multiplying locational marginal price estimates times expected load reductions. (5 TR 4911.) In this fashion, the customer's bill credit is tied directly to the value of actual load reductions. This is superior to offering a discount which is technically based on the rate's present revenue in relation to other residential rates, like how Rate D1.1's discount is currently established. Basing the discount on actual performance data reflects the actual purpose of Rate D1.1, which is to reduce costs for all power supply customers.

Staff recommends that the Company develop a new discount for Rate D1.1 that reflects the actual cost savings produced by interruptible customers. Decoupling charges from present revenue by rate would make the cost-benefit analysis for this DR resource easier to determine by making the discount explicitly

tied to a measure of cost savings, rather than an implied measure based on years of self-perpetuating rate designs. (5 TR 4912.) No parties provided rebuttal on Staff's recommendation.

For these reasons, the Commission and ALJ should approve Staff's recommendation that the Company provide the data necessary and to develop a discount for Rate D1.1 that is explicitly calculated to reflect the value provided by interruptible load.

**C. The non-interruption fee adder for Rate D8 must be updated for inflation.**

Rate D8 is the Company's interruptible supply rate for primary customers in which the Company may request that the customer reduce their load under certain economic or reliability conditions, rather than interrupting the customer directly like on Rate D1.1. (5 TR 4912.) The Rate D8 customer may avoid interruption by paying for the cost of replacement energy plus \$0.00576 per kWh (the "non-interruption fee adder" or "adder") plus a voltage level charge. Staff found that the non-interruption fee adder has not been updated in the Company's tariffs since at least 2003 when it was initially set. (5 TR 4913; S-13.2.) For this reason, Staff recommends that the adder be updated to reflect inflation since 2009, which is when the earliest version of the current adder appears in the Company's tariffs available on the MPSC website. Relying on the Bureau of Labor Statistics' inflation calculator Staff determined that the new adder should equal \$0.00880 per kWh. (*Id.*) In order to avoid rate shock for Rate D8 customers wishing to "pay-through"

interruptions, Staff recommends increasing the adder halfway to its full 2025 level by setting the non-interruption fee adder to \$0.00728 in the instant case and to the full \$0.00880 in its next general rate case. No parties provided rebuttal on Staff's recommendation. For these reasons the Commission and ALJ should approve Staff's recommendation to update the non-interruption fee adder for Rate D8.

**D. Demand and energy charges for primary power supply rates should maintain the currently-approved ratio.**

The Company proposes to design primary power supply rates by maintaining the currently approved ratio between demand and energy revenues. (4 TR 2591.) The Company determined its capacity and non-capacity revenue requirements in the same fashion as the previous case by relying on the SRM charge method, but the result of that determination was markedly different in the instant case. (5 TR 4963.) Staff identified that the cause of the large shift in revenue requirement is due to the reconciliation of 2024 projected energy sales revenue net of fuel costs with the actual amounts. (*Id.*) The effect of this large shift, along with the Company's maintenance of the split between demand and energy charges, created an unusual primary power supply rate design that produces a \$0.00 non-capacity demand charge and an increase of nearly double the Company's present capacity demand charge.<sup>9</sup> (A-16, Schedule F3, Page 27, lines 1, 17.) This also required the Company to create a capacity energy charge in order to maintain the previously

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<sup>9</sup> Present capacity and non-capacity demand charges are \$9.74/kW and \$7.25/kW, respectively. Staff relied on the same method as the Company and proposes capacity and non-capacity demand charges are \$17.05/kW and \$0.00/kW, respectively.

approved split between demand and energy charges. (4 TR 2585.) In previous cases the capacity revenue requirement was recovered exclusively through the demand charge.

The current Commission approved method of determining demand and energy charges for Rate D11 customers (and other primary customers with demand charges) is to set them based on present demand and energy charge revenue. (4 TR 2602.) In the instant case, 47% of present power supply revenue for the relevant primary customers comes from demand charges, while the remaining 53% comes from energy charges because that was the ratio set two cases ago. (5 TR 4449.) Therefore, the Company and Staff designed proposed power supply rates using the same ratio.

Essentially there are two related issues regarding primary power supply rate design: the large swings between capacity and non-capacity revenue requirements and the ratio between demand and energy revenue requirements. In cases prior to U-21297 the former determined the latter, so the ratio of capacity to non-capacity revenue was used to set the ratio of demand to energy revenue. (5 TR 4447-4449.) However, beginning in MPSC Case No. U-21297 the volatility between capacity and non-capacity revenue requirement made it so that it was no longer appropriate to rely on that ratio to set the demand/energy ratio. (Andrews, 4 TR 3215, Figure 2, 5 TR 4449.) Thus, in Case U-21297 the Commission approved Staff and ABATE's proposal to set the demand/energy charge ratio to the ratio approved in the previous case. (Turner, 4 TR 2604.) *In re DTE Electric's 2023 Rate Case*, MPSC Case No. U-

21297, 12/1/2023 Order, pp. 323-328. The Commission made the same determination in the Company's next rate case U-21534. (Turner, 4 TR 2604.) *In re DTE Electric's 2024 Rate Case*, MPSC Case No. U-21534, 1/23/2025 Order, p. 380.

ABATE argues that the SRM charge method to determine capacity and non-capacity revenue requirements can have a volatile effect on rate design; Staff agrees. (Isakson (Rebuttal), 5 TR 4922.) Staff identified a potential solution to the issue of large differences between forecasted and reconciled net energy sales. (*Id.*) In short, while it may have been appropriate in the past (i.e. before MPSC Case No. U-21297) to rely on the ratio of capacity to non-capacity revenue requirements to determine demand and energy charges, the difference between forecasted and actual sales *should* not be related to rate design. A better forecast or a different reconciliation process will alleviate these issues going forward.

ABATE takes issue with the fact that the Company and Staff's primary rate design resulted in a new capacity energy charge. (4 TR 3216.) ABATE argues that the creation of said charge required the Company to alter its tariff language for Rate R3. ABATE is concerned that the new tariff language is ambiguous and that the new capacity energy charge should only apply to back-up and maintenance power, and not self-supplied power. (4 TR 3216-3217.)

ABATE proposes to use an unorthodox method of determining power supply demand and energy charges. (4 TR 3217-3220.) ABATE proposes to determine power supply costs as either fixed or variable and to then recover all fixed costs via demand charges and variable costs via energy charges. (4 TR 3217-3218.) ABATE

deems total fuel costs less transmission, purchased power less purchased capacity, and total O&M expense less total labor costs are all variable (i.e., they vary with the energy used by customers) and therefore all other production costs are fixed.

ABATE's method suggests that 63% of power supply costs are fixed, with the remaining 37% are variable. (*Id.*) ABATE made the same proposal in Case U-21297. (4 TR 3219.) *In re DTE Electric's 2023 Rate Case*, MPSC Case No. U-21297, 12/1/2023 Order, p. 324.

Kroger notes that rate designs with higher demand charges and lower energy charges are favorable to customers with higher load factors, all else being equal. (5 TR 4450.) Therefore, ABATE's proposed method would result in higher demand charges than the Company and Staff's method and thus favor higher load factor customers. For reference: ABATE's method results in collecting 63% of revenue via demand whereas Staff and the Company use 47%. (5 TR 4921-4922.)

The Company argues that ABATE incorrectly conflates the allocation of revenue requirement between capacity and non-capacity with the split between demand and energy charges. (4 TR 2603.) Staff agrees, because the Commission has already fixed the demand/energy ratio to a historic amount, so technically the two issues are currently separated.

The Company disagrees with ABATE's fixed/variable method. (4 TR 2604.) The Company shows that ABATE's method results in a large under collection of capacity revenue and an over collection of non-capacity revenue. This creates a mismatch between how costs are allocated between capacity and non-capacity in the

cost of service study and how they are collected via rate design. (4 TR 2605.) The Company found that ABATE's method represents a significant departure from established cost of service methods previously approved by the Commission. (*Id.*) Staff agrees.

Staff argues that the cost of service study functionalizes, classifies, and allocates costs, but it does not deem those costs as fixed or variable. (5 TR 4920.) The Commission recognizes that a portion of power supply costs, namely production plant, should be allocated to energy. This means that some of the costs that ABATE considers as fixed and thus only recoverable via demand charges are currently allocated to energy. (5 TR 4920-492.) Staff further notes that costs are rarely ever fixed in the long run, so it is inappropriate to set rates as if they were. (*Id.*)

In MPSC Case No. U-21297 when the Commission approved the current method of setting the ratio between demand and energy charges the Commission also ordered that the issue should be revisited in the future. *In re DTE Electric's 2023 Rate Case*, MPSC Case No. U-21297, 12/1/2023 Order, p. 328. If the Commission approves Staff's proposal to enhance the forecast of energy market sales and thus dampen the large swings in revenue requirements created by reconciling the forecast to actuals, then perhaps in future rate cases it will be appropriate to revert to the previous method of allowing the capacity and non-capacity revenue requirements to inform the ratio of demand and energy charges. However, in the instant case it is obvious that the currently approved method of designing primary power supply rates is superior.

For the reasons explained by Staff and the Company, ABATE's proposal for primary power supply rate design by using its fixed/variable cost method should be rejected.

Kroger proposes to update the calculation of demand/energy ratio to also include present revenue derived from the non-capacity power supply on-peak charge premium. (Bieber, 5 TR 4456.) Kroger defines the on-peak premium as the difference between on- and off-peak energy charges for non-capacity power supply on Rate D11 (\$0.01 per kWh) times the present on-peak energy sales. (5 TR 4454-4455.) According to Kroger, the premium paid for on-peak energy can be considered demand-related, and thus appropriate to include in setting the demand/energy charge ratio. (*Id.*) The result of Kroger's proposed method is a ratio of 51% demand and 49% energy, as compared to the currently approved ratio of 47% demand and 53% energy. (5 TR 4457.)

Staff disagrees with Kroger's proposal to include on-peak premium revenue in the demand/energy ratio calculation. Kroger's assumption implies that non-capacity energy charges can be construed as capacity demand-related capacity costs. As explained in this brief, the previous method of using the ratio between capacity and non-capacity revenue requirements to determine the ratio of demand and energy charges worked reliably until reconciling energy market sales with inaccurate forecasts became an issue two cases ago.

Taking Kroger's argument that the premium paid for non-capacity on-peak energy is actually demand-related, then it makes more sense to apply the same

premium to the newly created capacity energy charge proposed by the Company. The Company proposes a flat per kWh energy charge in order to maintain the demand/energy ratio, so instead Kroger's proposal should create an on- and off-peak capacity energy charge in order to maintain the appropriate ratio. This would maintain the approved premium while still considering said premium as demand-related and collected in the same fashion as non-capacity revenue. Staff does not recommend the Commission approve Kroger's proposal to include on-peak premium non-capacity energy revenue to calculate demand and energy charges, nor the more appropriate application of Kroger's argument by creating on- and off-peak capacity energy charges. The overarching issue at hand is that the large difference between forecasted and actual energy market sales and their reconciliation has downstream effects on rate design, so fixing the root problem will solve the issue of rate design ratios without necessitating new methods of rate design.

For these reasons Kroger's proposal to include non-capacity on-peak premium revenue in determining demand and energy charges should be rejected.

**E. Universal lighting rates are more appropriate than technology-specific rates.**

The Company currently offers lighting rates for each specific lighting technology and wattage. (5 TR 4906.) Universal lighting rates are not tied to any specific lighting technology and vary only by the luminaire's wattage. (*Id.*) The Company no longer offers non-LED lighting to new customers, no longer services non-LED luminaires, and replaces out-of-service luminaires with LEDs. (*Id.*;

Hartley, 3 TR 1412, 1416.) Because lighting customers will soon all use the same lighting technology, it is appropriate to discontinue designing rates for every other technology individually. Consumers Energy Company began transitioning to LED-only lighting service earlier than the Company and currently offers universal lighting rates. (Isakson, 5 TR 4906.)

Furthermore, Staff testified that the Company's current method of determining lighting rates is overly complex compared to any of the Company's other rates, and that Staff does not have the necessary software capability necessary to precisely follow the Company's method. (Isakson, 5 TR 4906-4907.) Staff made certain adjustments to the Company's lighting rate design model in order to circumvent the software issue and recover Staff's proposed revenue requirement. Staff further explained that its alternative method will not adversely affect customers. (5 TR 4907-4908.) Implementing a universal lighting rate design model will simplify the rate design process and allow Staff to avoid making broad adjustments to the Company's model in order to produce the correct revenue requirement. (5 TR 4908-4909.) The Company agrees with Staff's recommendation to require the Company to file a proposal for universal lighting rates in its next rate case because that approach "aligns with broader goals of rate simplification and transparency." (3 TR 1452.)

For these reasons, the Commission and ALJ should approve Staff's lighting rate design and Staff's recommendation regarding a future proposal for universal lighting rate design.

**F. Staff's Recommendations Concerning the State Reliability Mechanism (SRM) Capacity Charge Revenue Requirement and True-up method.**

**[References in the Record:** Company witness Goyanes, 4 TR 2562-2566, A-16, Schedule F1.5; Company witness Burgdorf, 4 TR 2065-2071, A-26, Schedules P3-P4; Staff witness Pung, 5 TR 4962-4965, S-6, Schedule F1.5; Energy Michigan witness Zakem, 5 TR 3883-3919, EM-2 (AJZ-2), EM-3 (AJZ-3), EM-4 (AJZ-4), EM-5 (AJZ-5), EM-6 (AJZ-6), EM-7 (AJZ-7), EM-8 (AJZ-8); Company witness Burgdorf, 4 TR 2076-2077.]

The Company filed a SRM capacity revenue requirement and charge calculation in compliance with the Commission Order in Case No. U-21534. (4 TR 2562.) This included a true-up calculation that is included in the Company's proposed capacity charge in this case. DTE Electric, MPSC Case No. U-21534, January 23, 2025 Order, p. 390.

Energy Michigan witness Zakem in his direct testimony addresses the SRM calculation and true-up method. Concerning the SRM calculation, witness Zakem points out that the Company has included the variable component of purchased power costs in its determination of energy market sales revenue net of fuel costs and that no other Company currently includes this in its calculation. However, he stops short of making a recommendation on this topic. (5 TR 3901-3902.)

Concerning the true-up mechanism, he points out that the true-up is intended to help ensure that neither the utility collecting the SRM charge nor a customer paying it are at risk to forecast errors in the projecting of the revenues from the market price of energy and other electric services which serve as offsets to the capacity charge. (5 TR 3887-3888.) Witness Zakem then explains that due to timing flaws in the SRM statute and a formulaic method for true-ups, all future

true-ups using the present method will be in error. He states that under the present true-up method, the customer and the utility can be trued-up only if the customer pays an SRM charge in one year and also pays the charge in later years and that the true-ups end up infinitely pancaked. (5 TR 3902-3903.)

Concerning flaws in the current formulaic method submitted by the Company, Energy Michigan points out that the time period for actuals for the offsets value of energy market sales net of fuel have not exactly matched the test period. The actual period should be the same as the test year period. 5 TR 3898-3899. In addition to this flaw, witness Zakem also claims that the Company has erroneously included additional adjustments from prior cases U-18248 and U-20531 in its current formulaic true-up calculation. These adjustments total approximately \$329 million. (5 TR 3907-3908.) The amount can also be found on Company Exhibit A-26, Schedule P4, line 11.

Next, witness Zakem argues that there is flexibility in the SRM statute to allow for workable true-up methods and that the Commission is also guided by the cost-of-service statute, MCL 460.11(1). (5 TR 3911-3912) For these reasons witness Zakem recommends the Commission suspend the current formulaic true-up method in this proceeding. (5 TR 3913.) He also recommends that a customer specific true-up be implemented only when and if a customer is subject to the SRM charge. (5 TR 3914-3916.) This would be done by determining the difference between what the customer initially paid with projected energy market sales net of fuel compared to what the customer should pay with actual amounts. When actual amounts became

available, they would be substituted for projected amounts in recalculating the SRM capacity charge and the customer would be billed for or refunded the difference between the two calculated charges. (5 TR 3914.)

Staff witness Pung in his direct testimony points out that the Company's capacity revenue requirement in this case has increased by \$1.19 billion and the SRM capacity charge has increased by \$256.24 per MW-Day as a result. (5 TR 4963) Staff then points out that the main driver behind this massive increase is the Company's Reconciliation of Net Sales Benefit Difference in which it reconciles 2024 projected Energy Sales Revenues net of fuel costs from Case No. U-21297 with the actual amounts that occurred in that year. (*Id.*) This calculation can be found on Company Exhibit A-26, Schedule P4. This method has been referred to in this brief previously as the formulaic true-up method. The result of this method is a \$1.12 billion increase to the capacity revenue requirement, the largest factor being a \$877 million difference between the Company's 2024 projected energy market sales revenues and the actual revenues that occurred in 2024. (*Id.*) Staff then expressed concerns with the Company's energy market sales forecast in this case and recommended that the Commission require the Company to provide all the data it uses, including third party projections, to make its energy market sales forecast as part of its initial filing in its next rate case. This would include a calculation of its forecast in excel format with all formulas intact. (5 TR 4964-4965.)

In rebuttal, Company witness Burgdorf addresses Energy Michigan's discussion of variable costs from Power Purchase Agreements (PPAs) being included

in the projected fuel costs for the energy revenue sales net of fuel cost calculation. (4 TR 2076-2077.) First the Company points out that the issue of whether to include a variable component of PPAs as an offset to energy sales revenue was approved in Case No. U-21534. (4 TR 2077.) The Company also responds by again stating that it does not matter whether a portion of the PPA is considered variable or not. If these costs are not considered an offset, then they will be considered capacity-related and result in the same exact SRM capacity charge. (*Id.*) cNo other parties filed rebuttal testimony on the SRM calculation or true-up method.

Staff recognizes that the current formulaic true-up method has significant flaws. Up to this point, no customer has ever been charged the capacity charge because a load serving entity failed to meet their capacity obligations and therefore, no revenue has been collected because of it. There are no actual revenues to true-up. However, the formulaic true-up method is throwing the capacity and non-capacity revenue requirements far off the cost-to-serve. Approximately \$1.12 billion of revenue requirement is being shifted from non-capacity to capacity due solely to the formulaic true-up method which relies on accurate energy market sales forecasting. This is producing a result that does not adhere to cost-of-service principles in Staff's opinion. Staff agrees that there is flexibility in how the Commission provides for a true-up mechanism under Section 6w (4) of PA 341. This is evidenced by the fact that no other Company has an approved formulaic true-up in its SRM calculation up to this point and DTE did not originally include one in its previous case, Case No. U-21534. Staff also agrees that the Commission is also

guided by the cost-of-service statute MCL 460.11(1) which requires the establishment of electric rates equal to the cost of providing service to each customer class. For these reasons, Staff agrees that the current formulaic true-up method should be discontinued and removed in this case and the Company ordered to perform a true-up only if a customer is actually subject to the capacity charge and there is actual revenue to reconcile.

Concerning Energy Michigan's proposal to implement a customer-specific SRM true-up, Staff recommends a calculation that is more consistent with how the initial SRM capacity charge is implemented even though the result will be the same. If a customer is assessed the capacity charge, it is charged for the amount of MW-Days the customer requires the Company to serve them capacity. Staff recommends that if a true-up became necessary, that it would also be calculated and applied in this manner. First, the capacity charge would be recalculated for the applicable period using actual energy market sales data net of actual fuel costs. Then you would take the difference between the original capacity charge using projected amounts and the capacity charge produced using actual amounts and apply it to the amount of MW-Days the customer was charged.

Staff recommends that the current formulaic true-up method be discontinued in this case, but if the Commission elects to retain it, Staff would then recommend that approximately \$329 million from prior years true-ups in Cases U-18248 and U-20561 be removed from the capacity revenue requirement. These amounts have already been trued-up previously and should not be in the formulaic true-up in this

case. In this scenario, Staff also would agree with Energy Michigan that the actual period match the test period for the formulaic true-up.

Finally, regardless of which true-up method is approved by the Commission, Staff recommends that the Commission require the Company to provide all the data it uses, including third party projections, to make its energy market sales forecast as part of its initial filing in its next rate case. This would include a calculation of its forecast in excel format with all formulas intact. An accurate energy sales forecast net of projected fuel costs is critical to having an accurate capacity charge calculation and Staff needs the ability to review this forecast with the Company's initial filing.

**G. The Company should include Coincident Peak tests in its next rate case**

**[References in the Record:** Staff witness Kevin Krause 5 TR 5248.]

Staff witness Kevin Krause proposed that the Company in its next rate case present the coincident peak tests and comment on how it sees the outcome of these tests potentially changing in the future based on seasonal load forecasts (5 TR 5248). No one opposed this recommendation. Staff recommends that the Commission and ALJ find that the company should include coincident peak tests with comments about how the production allocator could potentially change over time.

**H. Transportation and Electric Vehicle (EV) Funding should be focused on maximizing benefits to customers**

**[References in the Record:** Company witness Neal Foley, 4 TR 2629, 4 TR 2661; Company witness Aaron Willis 4 TR 1790; Staff witness Kevin Krause, 5 TR 5247-5248; 5 TR 5246-5247; MEIU witness Sophia Schuster 5 TR 3989-3991, 5 TR 4005-4007, Walmart witness Matthew Lyon, 5 TR 4099.]

The Company in its direct filing proposed shifting funds within the Transportation Electrification Plan (TEP) in order to respond to demands for rebates (4 TR 2629). Staff witness Krause responded that funds should be shifted within the framework of maximizing benefits for customers. (5 TR 5247-5248.) Witness Schuster on behalf of the Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United (collectively MEIU) agreed in her direct testimony that shifting funding was problematic but proposed that it could possibly be done with “guardrails”. (5 TR 3989-3991.) Further, MEIU Witness Schuster in rebuttal also quibbled with Staff’s position suggesting that responding to market pressures has merit. (5 TR 4005-4007.) The Company through the rebuttal testimony of witness Foley, agreed with MEIU’s “guardrail” recommendation. (4 TR 2661.) However, Staff notes that no party in rebuttal testimony argued that Staff’s desire to maximize customer benefits was in error, preferring to stand firm on the ideas that it is appropriate to respond to market pressures on the demand for rebates. Therefore, Staff recommends that the arguments surrounding responsiveness to market pressures be rejected and asserts that the guardrail recommendation is vague and should be rejected as well. Moreover, Staff recommends that shifting in funding, if allowed, should be for the purpose of increasing customer benefits from the program. (5 TR 5247-5248.) Since

the original TEP is designed for customer benefits, any deviation from spending proposed in the TEP should be only considered with appropriate caution.

**I. Rate D3 should be closed to fast charging on June 1, 2028.**

Staff through witness Krause proposed closing Rate D3 to fast charging stations with demands over 1,000 kW on June 1, 2028. (5 TR 5246-5247.) Staff's principal reasoning is that allowing customers onto Rate D3 if their demand is over 1,000 kW is a subsidy. (5 TR 5246.) In conjunction with this proposal, Staff also proposed two additional items, that the Company file a fast charging tariff in its next rate case and that the rolling two-year provision be terminated, such that the June 1, 2028 date is made a firm deadline. (*Id.*) The Company, through the rebuttal of Aaron Willis, responded that it was on track to propose a cost-of-service based charging rate by December 2026 as previously directed by the Commission (4 TR 1790.) Staff would like to highlight that the Company position is not opposed to firmly ending the demand charge holiday on June 1, 2028.

In rebuttal, MEIU witness Schuster, disagreed with Staff, responding with a desire to have interested party meetings to discuss the components of the new fast charging tariff. (5 TR 4005-4006.) Walmart witness Lyons makes similar recommendations. (5 TR 4099.) MEIU even tries to call the timing into doubt, stating that "DCFC deployment and usage are not yet to the point to yield sufficient data that would allow the Company to develop, or the Commission to rule on, an informed D\*CFC-specific rate". (5 TR 4006.) The implied recommendation for MEIU is that we should wait until there is market stability or steady state

usage until a fast charging tariff is adopted. Staff is currently working on implementing tariffs for large users based on potential data centers, and there is no stability in the data center market. The idea that there should be stability before a tariff should be rejected.

Staff would also like to point out that the end of the demand charge holiday does not necessarily have to coincide with the implementation of a new fast charging tariff. Fast charging customers with a demand over 1,000 kW could be moved from Rate D3 to Rate D4 when the demand charge holiday ends. There would not necessarily need to be a new fast charging rate at that time. However, the Commission order in U-21534 could be interpreted to understand that the two are linked together. *In re DTE Electric's 2024 Rate Case*, MPSC Case No. U-21534, 1/23/2025 Order, p 418-425.

Lastly, Staff is not confident that interested party discussions will lead to a consensus tariff. Discussions will allow parties to express their ideas and concerns and could result in greater understanding, however, Staff expects parties to continue arguing for their various positions in future rate cases no matter how those interim discussions proceed.

Staff's recommendation remains that the demand charge holiday firmly conclude on June 1, 2028. Whether or not a new tariff is in place at that time is of limited concern for Staff, however, what is a concern for Staff is that any proposed rate be based on cost-of-service. All other elements of the rate can be open to further discussion.

**J. Residential Income Assistance (RIA), Low Income Assistance (LIA), Residential Senior Citizen (RSC), and Payment Stability Plan Pilot (PSP) Expenses Should be Reallocated in the Cost of Service Study**

**[References in the Record:** DTE witness Jason Sparks 4 TR 2737; DTE witness Theresa Uzenski 4 TR 2474-2475; A-13 C5.8.1; Staff witness Elaina Braunschweig, 5 TR 5215-5225; ABATE witness Brian Andrews (rebuttal), 4 TR 3226-3229

As outlined in section V (a) of this brief, Staff proposed recording the gap payments and on-time payment credits associated with the PSP pilot (totaling \$947 thousand) as a revenue offset in the COSS instead of in uncollectible expense. Related but ancillary to this proposed accounting adjustment is the issue of how the costs associated with the referenced energy assistance/lifeline credits are allocated (RIA, LIA, RSC). Staff raised the issue in direct testimony by stating that the Company currently allocates the revenue shortfall on a customer count basis, which assigns costs based on each customer class's share of the total customer base. (5 TR 5217.) Staff stated that other utilities, like Consumers Energy, allocate the revenue shortfall on total cost of service in the rate design models. (*Id.*) Staff therefore proposed to change the allocation method in the instant case and going forward to allocate RIA, LIA, RSC, and PSP pilot expenses on total billed revenue in the COSS as a temporary solution until the Commission responds to Staff's proposal in its Energy Affordability Report regarding energy assistance program cost allocation. (5 TR 5218, 5222.) Staff argued that this cost reallocation is supported by MCL 460.11(2) requiring costs associated with energy assistance/low-income rates to be allocated to all customer classes and that the cost of energy assistance is not attributable to any particular customer's service, rather it is a general cost of

business and unrelated to serving them energy. (5 TR 5218). Staff provided the table below to outline the percentage difference in allocators. (5 TR 5219.)

	<b>Residential Secondary</b>	<b>Commercial Secondary</b>	<b>Primary</b>	<b>Sub-transmission</b>	<b>Transmission</b>	<b>D-9 OPL Residential</b>	<b>D-9 OPL Commercial</b>	<b>E-1 St Lght</b>	<b>E-2 Signals</b>
<b>Total Billed Revenue (402)</b>	52.3344	26.1406	19.6296	0.1788	0.2163	0.0384	0.1769	1.1854	0.0997
<b>Distribution Number of Customers (800)</b>	90.5475	9.2745	0.1257	.0039	.0030	-	-	.0453	-

This issue is also present in the MPSC Staff Energy Affordability Report filed in MPSC Case No. U-20757 and the Commission should consider aligning its decision in the instant case with its decision in the U-20757 case docket and the impact on energy assistance program alignment across all regulated utilities. Energy Affordability Report, 9/10/2025, MPSC Case No. U-20757, pp. 186-193.

The Company did not respond in rebuttal testimony to Staff’s recommendation to change the allocation factor on the RIA, LIA, RSC, and PSP expenses in the COSS.

In rebuttal testimony, the Association for Businesses Advocating for Tariff Equity rebutted Staff in stating that the RIA, LIA, and RSC credit costs are attributable only to residential customers and are not a general cost of business. (4 TR 3226-3227.) ABATE witness Andrews claims that no other customer class benefits from the cost and that MCL 460.11 requires cost-based rates. (4 TR 3227.) ABATE witness Andrews argues that because the current allocation method

allocates 90.5% of the cost to the residential class, it more closely reflects his claim that residential customers cause 100% of the cost. (*Id.*) Witness Andrews recommended the Commission reject Staff's allocation proposal. (4 TR 3229.)

Staff notes the MCL 460.11 statute states, in relevant part:

(1) Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. [...]

(2) Notwithstanding any other provision of this act, the commission may establish eligible low-income customer or eligible senior citizen customer rates. Upon filing of a rate increase request, a utility shall include proposed eligible low-income customer and eligible senior citizen customer rates and a method to allocate the revenue shortfall attributed to the implementation of those rates upon all customer classes. As used in this subsection, "eligible low-income customer" and "eligible senior citizen customer" mean those terms as defined in section 10t.

The language in the statute is clear when in states in general that rates must be "equal to the cost of providing service to each customer class." The statute also states that low-income and eligible senior customer rates should be established and that a shortfall for those costs shall be recovered according to a method "upon all customer classes." In other words, the costs associated with energy assistance programs authorized under MCL 460.11(2) have to be recovered from all customer classes, and subsection 2 is exempt from the clause requiring cost-based rates.

The statute does not state by which allocator the costs must be recovered except that they must be recovered from all customer classes. Without providing assistance to customers, unpaid bills could result in being recorded in uncollectible expenses, as the Company proposed doing with PSP pilot expenses and Staff argued should only be applicable to arrears forgiveness, as discussed previously in this

brief. A decrease in uncollectible expenses could be beneficial to all customers. Therefore, Staff's proposal is consistent with the statute and, being that it has already been accepted by the Commission in the past, is reasonable and should be approved.

## VII. TARIFF ISSUES

**[References in the Record: Isakson, 5 TR 4913-4917; Turner, 4 TR 2597-5299; Willis, 4 TR 1749-1751.]**

### **A. The Company's proposed definition of residential minimum service should be removed.**

The Company proposes to update its tariff language in Section C6.1(16) of its rate book to define residential minimum service. (4 TR 1750.) The purpose of the update is to define when additional charges may be applicable to residential customers connecting loads greater than 10 kW or 9.6 kW for electric vehicle charging. Staff took issue with the wording of the proposed tariff language because it was accidentally defining minimum service instead of maximum service before additional fees would apply. (5 TR 4914.) Staff recommended the removal of the phrase "residential minimum service is 10 kW of connected load" in order to remove any confusion. (*Id.*) The Company agreed to the removal of the identified language on rebuttal. (4 TR 1791.) For these reasons the Commission and ALJ should approve Staff's recommendation to remove "residential minimum service is 10 kW of connected load" from proposed tariff language on Tariff Sheet No. C-27.00. This removal will not change the desired effect of the tariff. (5 TR 4914.)

**B. Tariffs should include a description of the D13 facilities allowance.**

Staff recommends that the Company, in its next general rate case, propose an exhibit, defining the calculation of the facilities allowance for Rate D13 and to include that calculation in its proposed tariffs in that case. (5 TR 4915.) The Company currently offers Rate D13 customers a facilities allowance, which is akin to contribution in aid of construction allowances or line extension allowances, which are both clearly available in the Company's current rate book. Staff reasons that "enshrining Commission-approved procedures which rely on rates into the rate book allows customers to be certain of fair treatment by the Company." (*Id.*) No parties provided rebuttal of Staff's proposal, which would not affect the charges or cost to serve customers. For these reasons, the Commission and ALJ should approve Staff's recommendation to require the Company to include the Rate D13 facilities allowance calculation in its proposed tariff sheets in its next general rate case.

**C. The Company should reformat its tariffs to make miscellaneous charges easier to identify.**

Staff recommends that the Company propose tariffs in its next general rate case that reformat any sections or pages that contain specific charges within the body of a text block. (5 TR 4915.) Staff argues that it is difficult for readers of the tariffs to identify minor charges that appear as part of a text block rather than clearly delineated among other charges. (*Id.*) Listing specific charges within descriptive text also makes them more difficult to update regularly, such as the Rate D8 non-interruption fee adder which had not been updated for over twenty

years. (S-13.2.) No parties provided rebuttal of Staff's recommendation. For these reasons the Commission should direct the Company to, as much as practicable, propose tariffs in its next case that move miscellaneous charges out of bodies of text and on to separate line items or some other reasonable method of distinguishment.

## **VIII. INFRASTRUCTURE RECOVERY MECHANISM**

**[References in the Record:** Staff witness Nicholas Evans, 5 TR 5284-5288, 5290, 5293-5294.]

### **A. Overview of IRM**

The Company is proposing to extend the IRM for three years, so that it includes 2027-2029, with the following capital programs included:

- Subtransmission Redesign and Rebuild
- Breaker Replacement
- URD Replacement
- System Cable
- Distribution Automation
- PTMM

The Company is also proposing additional amounts for 2026, which was already approved for inclusion in the IRM. Specifically, the Company wants to increase spending in the Subtransmission Redesign and Rebuild, Distribution Automation, and PTMM programs. (5 TR 5284-5285.)

Finally, the Company is proposing an enhanced stakeholder engagement process. (5 TR 5286.)

For 2026, Staff recommends keeping Subtransmission Redesign and Rebuild amounts the same at \$53.8 million, because the Company needs to provide a realistic and detailed actionable plan and additional data per the Commission's

order in MPSC Case No. U-21305. Staff recommends keeping the Distribution Automation amounts the same at \$24.4 million due to a disallowance being recommended by Staff. Finally, Staff agrees that \$200 million for Pole and Pole Top Maintenance and Modernization (PTMM) should be removed from rate base and added to the IRM for 2026. (*Id.*)

Staff recommends approving the three-year extension of 2027-2029. As far as specific programs, Staff is recommending the following:

1. Subtransmission Redesign and Rebuild – Staff recommends the alternative amounts of \$52.5 million for 2027, \$57.5 million for 2028, and \$60.0 million for 2029, because the Company needs to provide a plan and more data as directed by the June 12, 2025 order in Case No. U-21305.
2. Staff supports the Breaker replacement, URD replacement, and System Cable amounts proposed.
3. Distribution Automation – Staff recommends approving the amounts proposed by the Company, but the 2028 and 2029 amounts are contingent on meeting the requirements of the June 12, 2025 order in Case No. U-21305. On page 36 of that order, the Commission requested that DTE submit the Company’s strategy for improving safety and reliability to its 4.8 kV system prior to conversion. The Commission also requested that the plan describe planned timing for Viper recloser installation on the 4.8 kV for safety and reliability and

include an assessment that compares tree trimming and other alternative measures.

4. Staff supports adding PTMM to the IRM and supports the proposed investment amounts. (5 TR 5287-5288.)

Staff has additional recommendations for the Commission regarding the 2027-2029 IRM spending and the IRM review process: 1) If the Commission believes three years is too long a time period to approve, it can always approve only one year or two; 2) Staff is of the opinion that the Commission can reduce a year's approved amounts later in a subsequent rate case prior to that year occurring; and 3) Staff supports the Company's proposed IRM Technical Conference and Initial Stakeholder meetings. (5 TR 5290.)

Intervenor witnesses had various recommendations for the IRM in direct testimony. As summarized by Staff witness Nicholas M. Evans in his rebuttal testimony:

ABATE witness James Dauphinais recommends the Commission completely reject DTE's proposed alternative option for Year 3 (2026), IRM Year 5 (2028), IRM Year 6 (2029), and addition of the Pole and Pole Top Maintenance & Modernization (PTMM) IRM cost category. He also recommends limiting Year 4 (2027) investments. ABATE witness Colin Fitzhenry recommends reducing capital expenditures in the 2027-2029 IRM period for PTMM and Distribution Automation. Witness Curt Volkmann, testifying on behalf of the Clean Energy Organizations, recommends the Commission decline the inclusion of Subtransmission Redesign and Rebuild (SRR) investments in the IRM until the Company develops a BCA for SRR and identifies which projects have customer benefits that exceed customer costs. Witness Paul Alvarez, testifying on behalf of the AG, MEC, and NRDC, recommends the Commission terminate the IRM as of December 31, 2026. Witness Dennis Stephens, also testifying on behalf of the AG, MEC, and NRDC, recommends no IRM funding for Distribution

Automation for 2027-2029 and recommends rejecting the alternative proposal for 2026. For Subtransmission Redesign and Rebuild, he recommends rejecting DTE's request for 2027-2029 and recommends the Commission not consider the alternative proposal for 2026. For PTMM, he recommends rejecting DTE's request for 2027-2029. [5 TR 5293-5294.]

In his rebuttal testimony, Staff witness Evans recommended the Commission reject these proposals and adopt Staff's adjustments to the IRM. (5 TR 5294.)

**B. Distribution Infrastructure Recovery Mechanism (IRM) Rate of Return to be used for calculating incremental surcharge for years 2027, 2028, 2029**

[**References in the Record:** Staff witness Gerken, 5 TR 4972-4974, S-8.0, S-8.1, S-8.2, S-8.3, Staff witness Evans, 5 TR 5824-5290, Company witness Willis, 4 TR 1735-1749, 1755-1774, A-33, Schedule X1, A-33, Schedule X2, Company witness Vangilder, 3 TR 1595-1599, A-33, Schedule X4, A-33, Schedule X-5, Staff witness Gerken, 5 TR 4973, S-8.0 page 4 of 5, S-8.1.]

The Company proposes for the new IRM years being proposed in this rate case (2027 through 2029) its pre-tax rate of return rate of return (ROR) from Exhibit A-14, Schedule D-1, line to calculate the incremental revenue requirement. (3 TR 1597.)

Staff witness Evans recommends for 2027-2029 the rate of return associated with the IRM surcharge should be lower than the pretax rate of return as ordered in the instant case, but no lower than the short-term debt rate ordered in the instant case. Once these investments are found to be prudent and reasonable for inclusion in base rates in a future rate case, Staff intends for the normal ROR to apply. (5 TR 5288.)

In rebuttal, the Company witness Willis states in summary, the Company recommends the Commission reject the Staff IRM ROR proposal. (4 TR 1763.) Staff is recommending a lower rate of return for the 2027-2029 IRM because, for numerous years, it appears the Company under-invested in its distribution system. This is evident when comparing Company spending in the mid-2010s to the much higher amounts it is projecting to spend now and over the next several years. While Staff is not claiming the projections for the late 2020s are the correct amounts, they are probably closer in magnitude to what the distribution system requires than the amounts that were spent in the mid-2010s. This indicates past under-investment in the distribution system that the Company has only recently begun to turn around. In addition, the Liberty report found large inspection backlogs for some components of DTE's system, which also points to insufficient past investment in the system. Due to this previous under-investment, Staff believes that a lower rate of return should be built into the IRM surcharge. (5 TR 5288-5290.)

Finally, Staff recommends the rate to be used should the Commission approve any IRM amounts for years 2027, 2028, and 2029, be that as decided by the Commission in its final order. (5 TR 4974.) The Company confirms in response to audit question JSG-3.1c. (S-8.3, p. 3.)

## **IX. STAFF'S OTHER ISSUES**

### **A. The Commission Should Adopt Staff's Adjusted Line Loss Factor of 7.73%**

**[References in the Record:** Staff witness Hansen, 5 TR 5176-5178, S-22.3, S-22.4; Staff witness Isakson, 5 TR 4903-4904.]

In Staff's direct testimony, it recommended the adoption of an updated line loss factor. (5 TR 5178.) Staff made this recommendation because it finds the Company's line loss factor has been artificially inflated due to the Company's unregistered meters. (*Id.*) The Company's unregistered meters are communicating usage data to the Company, however, due to various reasons, these meters are not connected to a customer account, therefore, no customer is receiving a bill for this usage. (5 TR 5177.) As of July of 2025, the Company reported to Staff that there were 3,431 unregistered meters. (*Id.*) Because line loss is calculated using electricity sales, and because these sales are lower than they should be due to the unregistered meters, the Company's line loss factor of 7.76% is higher than it should be. (5 TR 5178.) No party took issue with Staff's position in rebuttal, therefore, the Commission should adopt Staff's calculated line loss factor of 7.73%.

The Company may recover unregistered meters and thus lead to the Company charging affected customers for some portion of their uncollected bills. (5 TR 4904.) In order to properly account for revenue collected in this manner in the future Staff recommends that the Company track the revenue as a regulatory liability until such time as it can be included as an offset to rates in future rate cases. (*Id.*) This will ensure that revenue is not double counted nor inappropriately excluded in future proceedings. No party disagreed with Staff's recommendation. For these reasons the Commission and ALJ should approve Staff's recommendation that the Company track future revenue collected resulting from uncollected bills due to unregistered meters as a regulatory liability.

**B. The Commission should reject the Company’s request to allow for contingency cost allowances in future proceedings.**

**[References in the Record:** Staff witness Hansen, 5 TR 5178-5180.]

In the Company’s direct testimony, witness Ludlow recommended that the Commission explicitly allow for the inclusion of contingency in cost allowances in future proceedings. (4 TR 2103.) In Staff’s direct testimony, it asserts that the Commission has made its position clear regarding contingency in prior proceedings. (5 TR 5179.) In the Commission’s December 9, 2021 Order in MPSC Case No. U-20940 the Commission states, “contingency is a forward looking, forecasted amount added to a budget to address unknown and unforeseen events. Once an amount has been spent, however, it is no longer a contingency but rather an actual expenditure and becomes subject to the reasonableness and prudence review that all actual expenditures undergo.” The Staff quoted this in testimony. (5 TR 5177.) Staff submits because it is unknown what contingency dollars will be used for before they are spent, it is impossible to review them for reasonableness and prudence in a rate case. No party took issue with Staff’s position in rebuttal; therefore, the Commission should not adopt the Company’s recommendation to allow for contingency cost allowances in future proceedings.

**C. The Company should provide more sales forecasting data with its next rate case filing, as witness Leuker has offered to do in response to Staff’s request.**

**[References in the Record:** Staff witness Paul Ausum, 5 TR 5238-5240, S-27.2; Company witness Markus Leuker (Rebuttal), 3 TR 1377-1379.]

Staff witness Paul Ausum recommends that, in all future general rate case filings, the Company include a modified Part III Attachment 3 (1) with actual historical customer class level sales, customers and monthly use per customer. Witness Ausum also recommends that the historical data included in Part III Attachments 3 (1) and 3 (2) be extended to correspond with the sample of data used to construct the models that the Company utilizes to forecast monthly sales and customer counts. Finally, witness Ausum requests that the data included with Part III Attachments 3 (1) and 3 (2) be reasonably inclusive of data extending beyond the historical test year. (5 TR 5238-5239.)

In rebuttal, Company witness Markus Leuker states that witness Ausum's recommendation to adjust the amount of data provided with the rate case filing attachments is an unreasonable one, on the basis that "rate case filing requirements extend to all Michigan utilities. Therefore, any changes should be made through the appropriate regulatory docket to allow all utilities and interested parties to have a voice." (3 TR 1378.) Witness Leuker also states that witness Ausum's recommendation is "not feasible and does not align with the Company's forecasting methodology." (*Id.*) As witness Leuker explains, both because sales and customers are forecasted on a class level and the advent of Advanced Metering Infrastructure, there exists potential alignment issues if class level sales and customers are included alongside the rate schedule data currently provided. (*Id.*) If Staff seeks the Company's forecasting inputs, witness Leuker states that "those inputs are provided regularly through Audit and in this instant case the Company provided

complete model inputs as well as forecasting project files when requested by Staff.” (3 TR 1378.) Witness Leuker closes by offering that “[t]he Company is willing to provide its forecasting model inputs as workpapers if desired by the Commission in its next Rate Case Filing.” (3 TR 1379).

Because the Company forecasts sales (load) and customers at the customer class level, and actual recorded sales and customers are the direct inputs to the load and customer forecasting models, it is important that any party that intervenes in the case be able to access those inputs. In sponsoring Part III Attachment 3 (1) as Exhibit S-27.2, witness Ausum simply provided a reference to the Commission as an example of the level of granularity and periodicity sought. Staff does not wish to prematurely reopen MPSC Case No. U-18238 for changes to the rate case filing requirements, but rather, all that Staff is seeking is to have the Company provide the raw data used to produce the forecast, in a format that is available to all intervenors. Staff commends the Company for providing the inputs and project files in this instant case. Witness Ausum’s request is a corollary to the data that is already provided in response to Staff audit or intervenor discovery. From the date that the Company files its rate case application, Staff (and other intervenors) have roughly four months to analyze the Company’s request and determine whether that request (and the inputs that comprise it) are reasonable and prudent. Data requests via audit and discovery impose additional temporal constraints to an already constrained timeline. Witness Ausum’s recommendation for more data in

future rate cases is simply an attempt to improve the efficiency of the rate case auditing process.

Staff is amenable to witness Leuker's offer to include all load and customer forecasting inputs as workpapers in all cases going forward. This should include the Company's Itron project files, as well as separate Microsoft Excel or comma separated value (csv) files that allow intervenors without access to Itron's proprietary software the ability to assess the forecasting inputs and construct their own models if needed. Forecasting is a complex task with a simple goal, i.e. to predict the future with the highest degree of accuracy. If the Company's data becomes accessible to all participants to a rate case, it only increases the probability that the forecast of load and customers adopted by the Commission is the most realistic depiction of the future.

The ALJ and Commission should order the Company to include the Itron project files related to the load and customer forecast as workpapers in all future cases. Additionally, the input data contained within those project files should be included separately in a universally accessible manner, subject to future protective orders.

**D. Staff agrees with the Company's proposal regarding outages.**

[References in the record: Staff witness Nicholas Evans, 5 TR 5284. Company witness Leslie, 3 TR 1037-1038.]

In the Company's last electric rate case, MPSC Case No. U-21534, the Commission agreed with Staff that:

[f]or credits paid for outages that exceed the duration limit, only those outages caused by a transmission operator or another utility should be recovered from ratepayers.

For credits paid to customers for exceedance of the outage frequency limit, the recoverable portion of the total credit amount provided to ratepayers should correspond only to outages caused by the transmission operator, another utility, or public interference. [MPSC Case No. U-21534, 1/23/25 Order, p. 357.]

Under the Company's cost recovery proposal in the instant case, the deferred costs would be reviewed in a subsequent rate case, and if approved by the Commission, the costs would be included in rates. The Company anticipates that the expense approved for recovery in rates would be amortized over a three-year period. (3 TR 1037.)

According to recent data, for the years 2022 through 2024, fewer than 110 customer outages in total would have qualified for cost deferral. Due to the small expense involved, the Company does not plan on pursuing cost recovery for these outage credits unless the expense becomes material. (3 TR 1037-1038.)

The Company has not included any expense in this rate case for customer outage credits. The Company's proposal is consistent with the Commission's order in U-21534, and Staff is supportive. (5 TR 5284.) No party filed rebuttal to Staff's position.

**E. Tree Trimming Recommendations.**

[References in the Record: Company witness Rachel C. Steudle, 4 TR 2847-2901; Staff witness Jessica Duell, 5 TR 5260-5266; Ann Arbor

witness Melissa Stults, 4 TR 3718-3724; CUB-NRDC<sup>10</sup> witness Rick Bunch, 5 TR 4849-4850.]

### **1. Tree Trimming Overview**

Staff has several recommendations regarding tree trimming that the Commission and ALJ should adopt, each of which is discussed below. Staff witness Duell supports the Company's proposal to spend \$180,000,000 in Base O&M expenses for the projected test year for tree-trimming. (5 TR 5261.) Company Witness Steudle recommends the Company go towards a risk-based tree trim cycle after the Company completes the surge program.

### **2. Staff does not recommend that the Company move to a risk-based tree trimming cycle.**

Company witness Steudle testified that with a risk-based/variable cycle approach the Company would be adjusting cycle lengths based on tree species growth rates, risk of outages, and cost of trimming using LiDAR technology. (4 TR 2859.) Staff witness Duell recommends the Company not move towards a variable risk-based cycle for tree trimming. Staff points to the Commission's June 12, 2025 Order in MPSC Case No. U-21305 at page 22 where a cautious approach is discussed. Staff is concerned that extending some line miles to cycles that are 6 or 7 years may result in the Company experiencing an increase in vegetation, which could cause an increase in trimming backlog for their distribution circuits. As witness Steudle acknowledges in her testimony, Staff recommends caution to

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<sup>10</sup>Natural Resources Defense Council and Citizens Utility Board of Michigan is abbreviated NRDC-CUB.

prevent DTE from losing progress in their reliability efforts, so Staff recommends the Company continue on their second round of a 5-year trimming cycle. (5 TR 5263.)

Dr. Melissa Stults, a witness for the City of Ann Arbor and Mr. Rick Bunch, a witness for CUB-NRDC do not support the Company moving towards a risk-based tree trimming cycle as well. Witness Stults states in her testimony that DTE's plan to purposefully fall behind their 5-year cycle on over half of their circuits following the surge ignores Audit findings and the Commission recommendation. She also goes on to state that rate payers paid for the surge through increased rates in hopes for a better reliable service once DTE completed their 5-year cycle and ratepayers should get the benefit of that bargain. (4 TR 3723.) Witness Bunch testified that the Company should not adopt a risk-based trimming cycle but instead follow the Commission's Order in the Liberty Audit case, which is MPSC Case No. U-21305, and maintain the five-year trim cycle for all circuits. Witness Bunch further testified that no substantive information has surfaced since the Commission's Order on June 12, 2025, indicating that its decision needs to be revised and trim cycles lengthened. (5 TR 4849-4850.)

DTE testified in rebuttal regarding Staff's recommendation of not supporting the Company moving towards a risk-based cycle after the surge program is completed. Company witness Steudle testified that in the Liberty Audit report part one and two, Liberty recommended the Company examine shifting towards a 4-year cycle and complete a study of cycle changes as soon as the Company can. Witness

Steudle bases her rebuttal off of these findings in the Liberty report to argue that the Company is doing this by moving towards a risk-based cycle. (4 TR 2891-2892.)

DTE testified in rebuttal regarding witness Stults's recommendation of not supporting the Company moving towards a risk-based cycle. Witness Steudle argues that the premise that witness Stults uses is flawed for two reasons. First, the Liberty audit did not provide an endorsement of 4- or 5-year tree trimming cycle as an end point but should be interpreted instead as a step toward a more mature and refined tree trim program which DTE will utilize with a risk-based approach. Second, the Liberty Audit suggests there may not be a discernable reliability benefit associated with the incremental cost in moving from a 5-year cycle to a 4-year cycle. Witness Steudle testified that in reality the risk-based approach enables the Company to shorten the cycle length for some circuits. Witness Steudle further testified that almost 40% of DTE's customers reside on circuits that will move to an accelerated 4-year cycle and over two-thirds of customers will be on circuits with a 4 or 5-year cycle. (4 TR 2892-2894.)

DTE testified in rebuttal regarding witness Bunch's recommendation of not supporting the Company moving towards a risk-based cycle because of the potential of falling back on progress gained by the Surge program. Witness Steudle testified that risk-based will relatively cost less than a 5-year cycle but will maintain a significantly higher base budget than historically forecasted for post-Surge. She further testified that the Company's requested funding for 2026 is in line with investment levels during the Surge program (4 TR 2900).

After reviewing DTE's rebuttal testimony and other parties' testimony, as outlined above, Staff maintains its position that the Company should not move towards a risk-based cycle approach and continue onto their second round of a five-year cycle. Staff recommends that the Company not move towards a risk-based cycle because Staff does not recommend that cycle lengths extend past 5 years. For the reasons outlined above, Staff recommends that the ALJ and Commission adopts its recommendations.

**3. Staff recommends that a report regarding tree trimming be filed within 2 years of the Commission's final order in this rate case.**

Company witness Steudle recommends an alternative method to study the incremental benefit and cost of expanding the trimming on Zone 2 and Zone 3. Company witness Steudle testified that the Company engaged with a third-party consultant with industry expertise in utility vegetation management and found that it would be better for the Company to remove softwood overhang past the first protective device (4 TR 2871-2872). Staff witness Duell supported the Company's proposal to remove softwood overhang beyond the first protective device (5 TR 5264). DTE did not rebut witness Duell's support.

Staff recommends, and Staff witness Duell testified that the Company should provide a report within two years of the completion of this rate case on softwood overhang removal. The following data should be included in the report: how much softwood overhang was cleared each year since beginning this practice (in miles or another appropriate unit), how much zone overhang was removed over

those same years, how many outages occurred due to overhang damage, and lastly, the change in all weather SAIDI and SAIFI due to softwood overhang removal. Staff recommends this report be filed within two years of the completion of this rate case (5 TR 5264.)

DTE agreed with Staff witness Duell's recommendation but had a few recommended changes to the report. DTE would like to collaborate with the MPSC Staff to refine the proposed study. The Company believes it's important to consider the benefits and cost of the proposed overhang expansion along with other two proposed changes to the specification (underbrush removal and outside? ROW removals) (4 TR 2887). Staff agrees with the Company's proposal and will work with the Company on the expected contents of the report.

Staff witness Duell also recommends DTE complete an analysis of moving towards a 4-year tree trimming cycle. Staff recommends the Company provide the costs associated with moving towards an effective 4-year tree trimming cycle and explain in detail the advantages and disadvantages of moving towards a 4-year tree trimming cycle (5 TR 5264). DTE did not rebut Witness Duell's recommendation. Thus, Staff recommends that the ALJ and Commission adopt its recommendations regarding a tree trimming report.

#### **F. Staff's Storm Restoration Recommendation**

**[References in the Record:** Company witness Allen J. Kryscynski, Jr., 3 TR 1250. Staff witness Duell, 5 TR 5265.]

Staff has a recommendation regarding Storm Restoration that the Commission and ALJ should adopt, which is discussed below. Staff witness Duell

supports the Company's proposal to spend \$94,979,000 for the projected test year O&M expense in service restoration, except for any adjustments recommended by Staff witness Shannon Rueckert. (5 TR 5265).

Staff witness Duell recommends DTE provide a description in future rate cases of what the Company defines as storm restoration expenses and describe what the Company plans on spending their projected storm restoration O&M expenses on. Staff also recommends DTE provide a detailed explanation of what the Company has spent storm restoration O&M expenses on in the most recent three calendar years as well. (5 TR 5265.) Company witness Kryscynski replied in his rebuttal testimony, agreeing with Staff and stating the company will provide added support and increased detail for storm restoration O&M expenses in future rate cases as requested. (3 TR 1250.) Thus, Staff recommends that the ALJ and Commission adopt its recommendation regarding added support for storm restoration O&M expenses in future rate cases.

**G. Staff recommends accounting approval regarding the Inflation Reduction Act (IRA) 1706 loan program.**

**[References in the Record:** Staff witness Rueckert, 5 TR 5195.]

The Company requested approval for the use of account 182.3 for issuances costs related to the 1706 loan program if financing from the program does not close. Staff recommends approval for accounting purposes only. Recovery of reasonable and prudent costs should be considered in future rate proceedings. This does not reduce the evidentiary burden the Company must meet before it may recover these costs in a future rate proceeding.

## H. Energy Assistance Program Reform

[References in the Record: DAAO witness Yunus Kinkhabwala 5 TR 4210, 4249, DAAO witness Toyia Watts 5 TR 4176; DAAO witness Justin Schott 5 TR 4416-4418; Staff witness Elaina Braunschweig (Rebuttal), 5 TR 5227- 5229.]

In direct testimonies of the Detroit Area Advocacy Organizations (DAAO), Witnesses Yunus Kinkhabwala, Toyia Watts, and Justin Schott proposed increasing energy assistance funding and for the Commission to approve a percentage of income payment plan (PIPP) and community-wide affordability program (CWAP). (5 TR 4210, 4249; 5 TR 4176; 4416-4418.) In rebuttal testimony, Staff witness Braunschweig cited the MCL 460.11(2) statute with its energy assistance program eligibility criteria outlined in MCL 460.10t(6)(b). (5 TR 5227.) This statute is important to keep in mind when considering proposals like the CWAP, in which DAAO witness Schott proposed enrolling customers in assistance based on census tracts instead of ensuring eligibility criteria are met. Staff additionally quoted the DTE Electric rate case order issued by the Commission in MPSC Case No. U-21534, in which the Commission states:

Therefore, the Commission finds that the LIA credit should be increased to \$50. However, the Commission finds that after final decisions and recommendations are provided by the EAAC, the Commission may continue to refine the LIA program in the future, including potentially changing the amount of this credit. [MPSC Case No. U-21534, 1/23/25 Commission Order, p. 405.]

EAAC stands for the Energy Affordability and Accessibility Collaborative. (5 TR 5228.) As quoted in Staff testimony, the Commission reaffirmed its position in Consumers Electric's rate case, MPSC Case No. U-21585, by disallowing large-scale energy assistance reform as well in stating:

However, the Commission agrees with the Staff that the instant rate case is not the appropriate forum for such policy modifications. As already noted by the ALJ, the Commission is currently reviewing low-income programs in numerous forums, including in the EAAC and EWR plan proceedings. [MPSC Case No. U-21585, 3/21/25 Commission Order, p. 391.]

EWR stands for energy waste reduction. (5 TR 5228.) As a fulfillment of the cited low-income energy assistance program work, Staff filed an Energy Affordability Report in MPSC Case No. U-20757 on September 10, 2025. (*Id.*) Staff acknowledged that many topics and recommendations made in the instant case could overlap with the Energy Affordability Report. (*Id.*) Since the Commission's last stated position directed energy assistance and affordability reform to emanate from that report, Staff recommends the Commission take a consistent approach in aligning its decisions in the instant case with those it concludes from the report. (5 TR 5229.)

**I. Residential Shutoff Protections: Staff recommends that all extreme weather conditions and critical care customer policies be addressed in their respective dockets.**

**[References in the Record:** Staff witness Anne Armstrong, 5 TR 5308-5318; Schott, 5 TR 4399-4411; DAO-409, DAO-415, DAO-418, DAO-421, DAO-432, DAO-455, DAO-456, DAO-457, DAO-458, DAO-459, DAO-460, DAO-461, DAO-462, DAO-463, DAO-464, DAO-465, DAO-467, DAO-468, DAO-469, DAO-470, DAO-471, DAO-472, DAO-473, DAO-474.

In rebuttal testimony, Staff references the Commission's current dockets on extreme weather and critical care protections in response to several of witness Schott's recommendations on residential shutoff protections for the Commission. (Schott, 5 TR 4399-4411.) Staff asserts that there are Commission directed

processes in specific dockets for Staff and interested parties to voice concerns and provide recommendations in these areas of residential shutoff protections.

In testimony, witness Schott recommends to the Commission seasonal summer shutoff protections that account for both extreme heat and wildfire smoke and expanded condition-based summer shutoff protections that set a conservative heat index threshold for all utilities. (5 TR 4404-4408, 4411) In rebuttal testimony, Staff states that the Commission directed comments on issues related to extreme weather through MPSC Case Number U-20140, August 7, 2025 Order. Staff contends that the appropriate forum to address witness Schott's extreme weather concerns could be in that forum. (Armstrong, 5 TR 5313-5314).

Regarding witness Schott's recommendation on a permanent medical / critical care protection for households with documented conditions, Staff states that in MPSC Case No. U-20757, June 12, 2025 Order, the Commission acknowledged the work of the Critical Care Collaborative (Collaborative) which detailed the goal of the Collaborative to discuss possible rule changes while focusing on the journey of a customer seeking the critical care shut off protection. (Schott, 5 TR 4400-4403, 4411; Armstrong, 5 TR 5316-5317) Staff states that Soulardarity and We Want Green, Too, were invited to the Collaborative and did not voice their concerns or make the recommendation that witness Schott professes in his testimony. Staff opines that for witness Schott to ask the Commission to review his recommendation in the instant case is dismissive of previous opportunities provided by the Commission for formal input. (Armstrong, 5 TR 5316 - 5317)

Staff recommends that extreme weather conditions and critical care customer policies be addressed in their respective dockets. More specifically, Staff recommends that the Commission take note of the current work in MPSC Case No. U-20140, August 7, 2025 Order seeking comment on topics related to extreme weather condition policies when responding to witness Schott's recommendations on residential shutoff protections; and take note of the previous work in U-20757 of the Critical Care Collaborative directed by the Commission when reviewing witness Schott's recommendations on shutoff protections for critical care / medical customers.

## **X. CONCLUSION**

Staff recommends that the ALJ and Commission find that DTE Electric's total revenue deficiency will be \$251.955 million. Staff recommends that the ALJ and Commission adopt Staff's lower rate base, return on equity and operating expenses, as well as Staff's proposed cost of service, rate design and tariff revisions. Staff's recommendations strike the right balance between DTE Electric's interests and its ratepayers' interests.

Respectfully submitted,

**MICHIGAN PUBLIC SERVICE  
COMMISSION STAFF**

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Dated: October 24, 2025

Michigan Public Service Commission  
DTE Electric Company  
Projected Revenue Deficiency (Sufficiency)  
Projected 12 Month Period Ending December 31 , 2026  
(\$000)

Case No.: U-21860  
MPSC Staff Initial Brief  
**Appendix A**

Line No.	(a) Description	(b) Source	(c) Applicant Projection	(d) Staff Adjustment	(e) Staff Projection
1	Rate Base	Exh. A-12, Sch. B1	\$ 23,560,071	\$ (390,346)	\$ 23,169,725
2	Adjusted Net Operating Income	Exh. A-13, Sch. C1	\$ 1,107,875	\$ 110,895	\$ 1,218,770
3	Overall Rate of Return	Line 2 ÷ Line 1	4.70%	0.56%	5.26%
4	Required Rate of Return	Exh. A-14, Sch. D1	6.03%	-0.42%	5.60%
5	Income Requirements	Line 1 x Line 4	\$ 1,419,871	\$ (121,610)	\$ 1,298,261
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	\$ 311,996	\$ (232,506)	\$ 79,491
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	<u>1.3496</u>	<u>-</u>	<u>1.3496</u>
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	\$ 421,081	\$ (313,797)	\$ 107,284
9	Return On - Tree Trim Regulatory Asset	Exh. A-11, Sch. A1.1	11,916	(7,062)	4,854
10	Return On - Monroe Regulatory Asset	Exh. A-11, Sch. A1.2	<u>141,070</u>	<u>(1,253)</u>	<u>139,817</u>
11	Revenue Deficiency / (Sufficiency)-Total	Sum Lines 8, 9, 10	<u>\$ 574,067</u>	<u>\$ (322,113)</u>	<u>\$ 251,955</u>

Michigan Public Service Commission  
DTE Electric Company  
Tree Trim Regulatory Asset - Return On  
Projected 12 Month Period Ending December 31 , 2026  
(\$000)

Case No.: U-21860  
MPSC Staff Initial Brief  
Appendix A1.1

Line No.	(a) Description						(b) Test Period Amount	(c) Reference		
1	<b>Return on Tree Trim Regulatory Asset</b>									
2	Average Balance Regulatory Asset						170,100	Line 16		
3	Deferred Tax Liability						(44,056)	- Line 2 x 25.9% Composite Tax Rate		
4	Average Net Rate Base						126,044			
5	Authorized Rate of Return on Short Term Debt (pretax)						3.85%	Exhibit A-14, Schedule D1		
6	Return on Tree Trim						4,854			
		<b>2019-A</b>	<b>2020-A</b>	<b>2021-A</b>	<b>2022-A</b>	<b>2023-A</b>	<b>2024-A</b>	<b>2025</b>	<b>2026</b>	
7	<b>Tree Trim Regulatory Asset</b>									
8	Approved Tree Trim - Surge Funding	43,300	74,100	70,500	58,200	67,000	54,438	128,962	-	Exhibit A-13 C5.6.1, Line 2
9	Carrying Charges through April 30, 2020 1/		1,200							
10	Regulatory Liability Balance Transfer 4/	-	-	-	-	-	(601)	-	-	
11	Total Tree Trim Reg Asset Deferral	43,300	75,300	70,500	58,200	67,000	53,838	128,962	-	
12	Total Tree Trim Reg Asset Cumulative	43,300	118,600	189,100	247,300	314,300	211,238	340,200	340,200	Cumulative Line 11
13	Securitization Amount 2/ 3/					(156,900)			(340,200)	
14	Cumulative Balance at December 31					157,400	211,238	340,200	-	
15	Cumulative Balance at December 31							340,200	-	Assumes 100% of annual spend
16	Average Balance								170,100	

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

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

3/ The Company plans to securitize \$340M in 2026

4/ Remaining balance of regulatory liability transferred to regulatory asset per U-21128

**Michigan Public Service Commission**  
**DTE Electric Company**  
**Monroe Regulatory Asset - Return On**  
**Projected 12 Month Period Ending December 31 , 2026**  
**(\$000)**

Case No.: U-21860  
 MPSC Staff Initial Brief  
**Appendix A1.2**

Line No.	(a) Description	(b) Test Period Amount	(c) Reference
1	<b><u>Return on Monroe Regulatory Asset</u></b>		
2	Monroe Regulatory Asset - Average Balance	2,143,277	Exhibit A-12, Schedule B4.4, Line 8
3	Pre-tax Weighted Average Cost of Capital 1/	<u>6.52%</u>	Exhibit S-4, Schedule D1
4	Return on Monroe Regulatory Asset	<u>139,817</u>	

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

**Michigan Public Service Commission**  
**DTE Electric Company**  
**Projected Rate Base**  
**Periods Ending December 31, 2023 and December 31 , 2026**  
**(\$000)**

Case No.: U-21860  
MPSC Staff Initial Brief  
**Appendix B**

	(a)	(b)	(c)	(d)	(e)
<b>Line No.</b>	<b>Description</b>	<b>Source</b>	<b>Applicant Projection</b>	<b>Staff Adjustment</b>	<b>Staff Projection</b>
			(13 Month Average)	(13 Month Average)	(13 Month Average)
1	<u>Utility Plant in Service:</u>				
2	Plant in Service	Exh. A-12, Sch. B2, L6	26,185,184	(407,432)	25,777,752
3	Plant Held for Future Use	Exh. A-12, Sch. B2, L7	224	-	224
4	Construction Work in Progress	Exh. A-12, Sch. B2, L8	2,637,403	-	2,637,403
5	Acquisition Adjustments	Exh. A-12, Sch. B2, L9	<u>77,542</u>	<u>-</u>	<u>77,542</u>
6	Total Utility Plant	Sum Lines 2 thru 5	28,900,353	(407,432)	28,492,921
7	Depreciation Reserve	Exh. A-12, Sch. B3, L6	<u>(6,922,615)</u>	<u>22,910</u>	<u>(6,899,705)</u>
8	Net Utility Plant	Line 6 + Line 7	21,977,738	(384,522)	21,593,216
9	Net Capital Lease Property	Exh. A-12, Sch. B4.1, col. (c), L10	5,735	-	5,735
10	Property under Operating Leases	Exh. A-12, Sch. B4.1, col. (c), L11	-	-	-
11	Net Nuclear Fuel Property	Exh. A-12, Sch. B4.1, col. (c), L12	<u>207,030</u>	<u>-</u>	<u>207,030</u>
12	Total Utility Property and Plant	Sum Lines 8 thru 11	22,190,503	(384,522)	21,805,981
13	Less: Capital Lease Obligations	Exh. A-12, Sch. B4.1, col. (c), L85 + L100	<u>5,815</u>	<u>-</u>	<u>5,815</u>
14	Net Plant	Line 12 - Line 13	22,184,688	(384,522)	21,800,166
15	Allowance for Working Capital	Exh.A-12, Sch. B4	<u>1,375,383</u>	<u>(5,824)</u>	<u>1,369,559</u>
16	Total Rate Base	Line 14 + Line 15	<u>23,560,071</u>	<u>(390,346)</u>	<u>23,169,725</u>

DTE Electric Energy Company  
 Development of Projected Net Operating Income  
 for the Test Year Ended December 31, 2026  
 (\$000)

Line No.	(a) Description (Witness)	Revenue				Expenses								NOI				
		(b) Sales Revenue	(c) Base Fuel & Purchase Power Rev.	(d) Other Revenue and R2 Rider	(e) Total	(f) Fuel and Purchased Power	(g) Other O&M Expense	(h) Depreciation & Amort.	(i) Property Taxes	(j) Other Taxes	(k) State & Local Income	(l) FIT	(m) Other Utility (Income) / Deductions	(n) Total	(o) NOI	(p) AFUDC	(q) Loss on Reacquired Securities	(r) Adjusted NOI
1	<b>Company Filed</b>																	
	<b>Operating Income (Initial Filing)</b>	4,246,558	1,353,470	118,330	5,718,358	1,353,470	1,392,755	1,359,917	348,018	52,064	61,537	109,372	(6,425)	4,670,708	1,047,651	62,659	(2,435)	1,107,875
	<b>Staff Adjustments</b>																	
2					-													
3	Sales Adjustment (Isakson)	5,722			5,722						355	1,127		1,482	4,240			4,240
4					-													
5	PSCR Offset (Isakson)		(983)		(983)						(61)	(194)		(255)	(728)			(728)
6					-													
7	<u>Other Revenue</u>																	
8	Other Operating Revenue (Isakson)			2,693	2,693						167	530		698	1,996			1,996
9	Payment Stability Plan (Braunschweig)			(947)	(947)						(59)	(186)		(245)	(702)			(702)
10					-													
11	<u>Steam Power Generation</u>																	
12	BRPP U2 Turbine Support Restoration (Kindschy)						(2,334)				145	460		(1,729)	1,729			1,729
13	Belle River Startup Study and Tuning (Kindschy)						(250)				16	49		(185)	185			185
14	Belle River Unit 1 Boiler Chemical Cleaning (Kindschy)						(3,000)				186	591		(2,223)	2,223			2,223
15	Belle River Chemical Resin Replacements (Kindschy)						(800)				50	158		(593)	593			593
16	Monroe Reliability Maintenance (Kindschy)						(3,843)				239	757		(2,847)	2,847			2,847
17	Belle River Fuel Handling Post Natural Gas Conversion (Kindschy)						(3,520)				219	693		(2,608)	2,608			2,608
18	Steam Generation Periodic Outage Normalization (Kindschy)						(4,372)				272	861		(3,239)	3,239			3,239
19	Total Steam Power Generation - Inflation (Kindschy)						(2,039)				127	402		(1,511)	1,511			1,511
20					-													
21	<u>Fuel Supply &amp; MERC Fuel Handling</u>																	
22	Total Fuel Supply & MERC Fuel Handling - Inflation (Kindschy)						(92)				6	18		(68)	68			68
23					-													
24	<u>Nuclear Power Generation</u>																	
25	Total Nuclear Power Generation - Inflation (Kindschy)						(1,354)				84	267		(1,003)	1,003			1,003
26					-													
27	<u>Hydraulic Power Generation</u>																	
28	Total Hydraulic Power Generation - Inflation (Kindschy)						(131)				8	26		(97)	97			97
29					-													
30	<u>Other Power Generation</u>																	
31	Trenton BESS Operation (Kindschy)						(914)				57	180		(678)	678			678
32	Peaker Increased Maintenance (Kindschy)						(4,303)				267	847		(3,188)	3,188			3,188
33	Total Other Power Generation - Inflation (Kindschy)						(295)				18	58		(219)	219			219
34					-													
35	<u>Distribution</u>																	
36	Total Distribution - Inflation (Rueckert)						(3,223)				200	635		(2,388)	2,388			2,388
37					-													
38	<u>Uncollectible Accounts Expense</u>																	
39	Payment Stability Plan (Braunschweig)						(947)				59	186		(702)	702			702
40	Uncollectible Accounts Expense (Rueckert)						(614)				38	121		(455)	455			455
41					-													
42	<u>Regulated Marketing</u>																	
43	DR Call Center (Towslee)						(300)				19	59		(222)	222			222
44	Regulated Marketing Inflation (McMillan-Sepkoski)						(244)				15	48		(181)	181			181
45					-													
46	<u>Corporate Support</u>																	
47	Incentive Compensation - Financial Measures (McMillan-Sepkoski)						(35,838)				2,226	7,059		(26,554)	26,554			26,554
48	Restricted Stock (McMillan-Sepkoski)						(7,730)				480	1,522		(5,727)	5,727			5,727
49	Communication Compliance and Data Loss Prevention (DLP) Diversification (Zir)						(283)				18	56		(210)	210			210
50	Customer Insight Platform Application Health (Klocke)						(100)				6	20		(74)	74			74
51	Customer Relationship and Billing Program (Klocke)						(2,695)				167	531		(1,997)	1,997			1,997
52	DTE Mobile App Application Health (Klocke)						(170)				11	34		(126)	126			126
53	Outage WISMO and Map Sustainment (Klocke)						(249)				15	49		(185)	185			185
54	Outage WISMO, PPS, and Map Enhancement Klocke)						(525)				33	103		(389)	389			389
55	Projects with level 2 cost estimates (Rogers)						(16)				1	3		(12)	12			12
56	Projects with level 3 cost estimates (Rogers)						(2,086)				130	411		(1,545)	1,545			1,545
57	Corporate Support and Inflation (Rueckert)						(23,065)				1,432	4,543		(17,090)	17,090			17,090
58					-													
59	Employee Pension and Benefits (Rueckert)						(7,136)				443	1,405		(5,287)	5,287			5,287
60					-													
61	Impact of Cap Ex Adj on Prop. Tax & Depr. (Hecht)								(28,453)	(1,955)	1,888	5,989		(22,530)	22,530			22,530
62					-													
63	Remove Prop. Tax Exp. From Intangible Plant Cap Ex								(1,743)		108	343		(1,291)	1,291			1,291
64	Proforma Interest (Nichols)										255	810		(1,065)	(1,065)			(1,065)
65	Interest Synchronization (Nichols)										(0)	(0)		(1)	1			1
66	<b>Total Adjustments</b>	5,722	(983)	1,747	6,486	-	(112,468)	(28,453)	(3,698)	-	9,639	30,570	-	(104,409)	110,895	-	-	110,895
67	<b>Staff NOI - Test Year</b>	<u>4,252,281</u>	<u>1,352,488</u>	<u>120,076</u>	<u>5,724,844</u>	<u>1,353,470</u>	<u>1,280,288</u>	<u>1,331,464</u>	<u>344,320</u>	<u>52,064</u>	<u>71,176</u>	<u>139,943</u>	<u>(6,425)</u>	<u>4,566,299</u>	<u>1,158,546</u>	<u>62,659</u>	<u>(2,435)</u>	<u>1,218,770</u>

Michigan Public Service Commission  
DTE Electric Company  
Projected Rate of Return Summary  
For the 13-Month Average Period Ending Dec. 31, 2026

Case No.: U-21860  
MPSC Staff Initial Brief  
Appendix D

Line No.	(a) Description	(b) Amount (\$000)	Capital Structure		(e) Cost Rate %	Weighted Costs			
			(c) Percent Permanent Capital	(d) Percent of Total Capital		(f) Permanent Capital	(g) Total Cost %	(h) Conversion Factor	(i) Pre-Tax Return
1	Long-Term Debt	9,213,994	50.00%	39.11%	4.27%	2.13%	1.67%	1.0000	1.67%
2	Preferred Stock	0	0.0%	0.00%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Shareholders' Equity	<u>9,213,994</u>	<u>50.00%</u>	39.11%	9.80%	<u>4.90%</u>	3.83%	1.3496	5.17%
4	Total	18,427,988	<u>100.0%</u>			<u>7.03%</u>			
5	Short-Term Debt	562,850		2.39%	3.85%		0.09%	1.0000	0.09%
6	Investment Tax Credit (ITC) - Debt	17,096		0.07%	4.27%		0.00%	1.0000	0.00%
7	Investment Tax Credit (ITC) - Equity	<u>17,096</u>		0.07%	9.80%		0.01%	1.3496	0.01%
8	Total Investment Tax Credit (ITC)	34,192							
9	Deferred Income Taxes (Net)	<u>4,535,041</u>		<u>19.25%</u>	0.000%		<u>0.00%</u>		<u>0.00%</u>
10	Total	<u>23,560,071</u>		<u>100.00%</u>			<u>5.60%</u>		<u>6.95%</u>

Michigan Public Service Commission  
DTE Electric Company  
Capital Expenditure and Rate Base Adjustments  
Projected Balances Period Ending December 31, 2026  
(\$000)

Line	Adjustment Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Total Cap Ex Adj.	Plant	Accum Depr.	Rate Base	Depreciation	Property Tax
1	<b>Production Plant:</b>							
2	Steam - Other - Trenton Channel BESS		(31,953)	(15,977)	(259)	(15,718)	(518)	(982)
3	<b>TOTAL: PRODUCTION PLANT</b>		<b>(31,953)</b>	<b>(15,977)</b>	<b>(259)</b>	<b>(15,718)</b>	<b>(518)</b>	<b>(982)</b>
4								
5	<b>Distribution Base Capital Programs:</b>							
6	Emergent Replacements		(101,610)	(75,820)	(2,577)	(73,243)	(3,105)	(529)
7	Customer Connections, Relocations & Other		(29,370)	(21,915)	(745)	(21,170)	(897)	(153)
8	Electric System Equipment - Projected Meters		(12,844)	(9,573)	(325)	(9,248)	(392)	(67)
9								
10	<b>Distribution Strategic Capital Programs:</b>							
11	<b>Infrastructure Resilience and Hardening</b>							
12	Pole and Pole Top Maintenance and Modernization (PTMM)		(200,000)	(100,000)	(2,048)	(97,952)	(4,095)	-
13								
14	<b>Infrastructure Redesign and Modernization</b>							
15	Subtrans Redesign & Rebuild: Transformer High Side Protection Program		(7,575)	(6,069)	(218)	(5,851)	(249)	(48)
16	Subtrans Redesign & Rebuild: Reverse Power Relay Scheme Program		(400)	(300)	(10)	(290)	(12)	(2)
17	CODI: Alfred Substation Expansion		(2,608)	(2,428)	(96)	(2,333)	(99)	(24)
18	Subtransmission Redesign & Rebuild: Trunk 3509		(1,502)	(751)	(15)	(735)	(31)	(8)
19	CODI: Targeted Network Secondary Cable Replacement		(1,335)	(668)	(14)	(654)	(27)	(7)
20	4.8 kV CC: Calla Circuit Conversion and Phase 2		-	-	-	-	-	-
21	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion - North		(300)	(150)	(3)	(147)	(6)	-
22	4.8 kV CC: Melvindale		(360)	(180)	(4)	(176)	(7)	-
23	System Loading: Jewell		-	-	-	-	-	-
24	4.8 kV CC: I-94 Substation & Circuit Conv. (Promenade) - System Conduit		-	-	-	-	-	-
25	Subtransmission Redesign & Rebuild: Trunk 7105		(200)	-	-	-	-	-
26	4.8 kV CC: ISO Conversion Program		-	-	-	-	-	-
27	4.8 kV CC: New Baltimore		-	-	-	-	-	-
28	CODI: Garfield Network Upgrade		-	-	-	-	-	-
29	4.8 kV CC: Belleville Substation and Circuit Conversion		-	-	-	-	-	-
30	System Loading: Grenada		(16,500)	-	-	-	-	(54)
31	CODI: Howard Conversion		-	-	-	-	-	-
32	4.8 kV CC: Ann Arbor AC Network Conversion		-	-	-	-	-	-
33	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion		(684)	-	-	-	-	-
34	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion		-	-	-	-	-	-
35	4.8 kV CC: I-94 Substation & Circuit Conv. (Promenade) - 8098 & 8632		-	-	-	-	-	-
36	4.8 kV CC: I-94 Substation & Circuit Conv. (Promenade) - 9221 & 9601		-	-	-	-	-	-

Michigan Public Service Commission  
DTE Electric Company  
Capital Expenditure and Rate Base Adjustments  
Projected Balances Period Ending December 31, 2026  
(\$000)

Line	Adjustment Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Total Cap Ex Adj.	Plant	Accum Depr.	Rate Base	Depreciation	Property Tax
37	<b>Technology and Automation</b>							
38	CVR/WVO		(7,123)	(3,561)	(119)	(3,443)	(237)	-
39	Distribution Automation (part of IRM)		(133,353)	(97,804)	(5,335)	(92,468)	(6,520)	-
40	Distribution Sensing and Monitoring		(3,446)	(3,023)	(115)	(2,908)	(124)	(28)
41	Customer Power Status Visibility		(7,880)	(4,880)	(138)	(4,742)	(200)	(20)
42	Distribution SCADA Historian		(2,500)	(1,250)	(26)	(1,224)	(51)	-
43	Mobile Equipment Replacement		(1,750)	(875)	(18)	(857)	(36)	-
44	Mobile Timesheets		-	-----In CWIP with AFUDC offset-----				-
45	Vegetation Management Replatform		-	-----In CWIP with AFUDC offset-----				-
46	<b>TOTAL: DISTRIBUTION</b>		<b>(531,339)</b>	<b>(329,246)</b>	<b>(11,805)</b>	<b>(317,441)</b>	<b>(16,090)</b>	<b>(939)</b>
47								
48	<b>Demand Side Management:</b>							
49	Other Demand Response Programs and Pilots - C&I Battery Pilot		(508)	(508)	(159)	(349)	(102)	(10)
50	<b>TOTAL: DEMAND SIDE MANAGEMENT</b>		<b>(508)</b>	<b>(508)</b>	<b>(159)</b>	<b>(349)</b>	<b>(102)</b>	<b>(10)</b>
51								
52	<b>Information Technology:</b>							
53	Level 2 Cost Estimate Reductions		(685)	(343)	(34)	(308)	(69)	-
54	Level 3 Cost Estimate Reductions		(24,444)	(18,760)	(3,184)	(15,577)	(3,752)	-
55	Overhead Reductions		(15,504)	(9,733)	(1,719)	(8,014)	(1,947)	-
56								
57	<b>Customer IT</b>							
58	Customer Insight Platform Application Health		(4,275)	(2,138)	(214)	(1,924)	(428)	-
59	DTE Mobile App Application Health		(1,101)	(550)	(55)	(495)	(110)	-
60	Payment Merchant Fees		(9,998)	(9,998)	(2,000)	(7,999)	(2,000)	-
61	Outage WISMO and Map Sustainment		(8,250)	(5,625)	(863)	(4,763)	(1,125)	-
62	Outage WISMO, PPS, and Map Enhancements		(1,700)	(850)	(85)	(765)	(170)	-
63	Customer Relationship and Billing Program		(6,311)	(3,155)	(316)	(2,840)	(631)	-
64								
65	<b>Plant &amp; Field</b>							
66	Corporate Instance - Maximo Application Suite Upgrade Phase 2		(1,400)	(700)	(70)	(630)	(140)	-
67	Maximo Engineering Process Automation		(2,552)	(2,552)	(1,021)	(1,531)	(510)	-
68								
69	<b>Information Protection Security</b>							
70	Communication Compliance and Data Loss Prevention (DLP) Diversification		(370)	(278)	(46)	(232)	(56)	-

Michigan Public Service Commission  
DTE Electric Company  
Capital Expenditure and Rate Base Adjustments  
Projected Balances Period Ending December 31, 2026  
(\$000)

Line	Adjustment Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Total	Test Year Impacts From Staff Adjustment(s)					
		Cap Ex Adj.	Plant	Accum Depr.	Rate Base	Depreciation	Property Tax	
71	<b>Infrastructure Operations</b>							
72	Backup Environmental Growth	(200)	(150)	(25)	(125)	(30)	-	
73	Network Hardening and Operations Project	(500)	(250)	(25)	(225)	(50)	-	
74	Digital Worker Experience EOL Electric	(1,812)	(1,704)	(649)	(1,055)	(341)	-	
75	Field Worker Device EOL	(135)	(68)	(7)	(61)	(14)	-	
76								
77	<b>Enterprise Data Analytics</b>							
78	DO Productivity Center	(439)	(439)	(176)	(263)	(88)	-	
79	<b>TOTAL: INFORMATION TECHNOLOGY</b>	<b>(79,676)</b>	<b>(57,293)</b>	<b>(10,487)</b>	<b>(46,806)</b>	<b>(11,459)</b>	-	
80								
81	<b>Corporate Staff:</b>							
82	Electric Vehicle Fleet and Maintenance	(1,362)	(681)	(26)	(655)	(52)	-	
83	Facilities-Construction & Upgrades - Courtyard	(2,254)	(1,127)	(43)	(1,083)	(87)	-	
84	Other Miscellaneous	(1,500)	(1,100)	(69)	(1,031)	(85)	(7)	
85	<b>TOTAL: CORPORATE STAFF</b>	<b>(5,116)</b>	<b>(2,908)</b>	<b>(139)</b>	<b>(2,769)</b>	<b>(224)</b>	<b>(7)</b>	
86								
87	<b>Charging Forward:</b>							
88	Evs/Charging Hub	(1,500)	(1,500)	(61)	(1,439)	(61)	(16)	
89	<b>TOTAL: CHARGING FORWARD</b>	<b>(1,500)</b>	<b>(1,500)</b>	<b>(61)</b>	<b>(1,439)</b>	<b>(61)</b>	<b>(16)</b>	
90								
91								
92	<b><u>TOTAL CAPITAL EXPENDITURE ADJUSTMENTS</u></b>	<b><u>(650,091)</u></b>	<b><u>(407,432)</u></b>	<b><u>(22,910)</u></b>	<b><u>(384,522)</u></b>	<b><u>(28,453)</u></b>	<b><u>(1,955)</u></b>	
93								
94	<b><u>WORKING CAPITAL ADJUSTMENTS</u></b>							
95	Non Utility Balance included in Other Accounts Receivable Total				(5,824)			
96	<b>TOTAL: WORKING CAPITAL</b>				<b>(5,824)</b>			
97								
98	<b>TOTAL RATE BASE ADJUSTMENTS</b>				<b><u>(390,346)</u></b>			

Michigan Public Service Commission  
DTE Electric Company  
Summary of Staff Position  
Projected Balances Period Ending December 31, 2026

Appendix F  
MPSC Staff Brief  
Case No. U-21860

Line	(a) Description	(b) Source	(c) Rate Base	(d) Pre-Tax	(e) Revenue Requirement Impact (million \$)
<b>Walk from DTE Revenue Deficiency (Direct) to Staff Initial Brief</b>					<b>(million \$)</b>
1	<b>Company Revenue Deficiency (Direct)</b>				<b>\$ 574.067</b>
2	<b>Staff Adjustments</b>				
3	Rate base	Appendix E * Exhibit A-14, Sch D-1	(390.346)	7.52%	\$ (29.359)
4	Rate of return	Appendix B * (Appendix D less Exh A-14)	23,169.725	-0.58%	(133.334)
5	Revenue	Appendix C, line 66			(6.486)
6	O&M Expense	Appendix C, line 66			(112.468)
7	Depreciation	Appendix C, line 66			(28.453)
8	Property Tax	Appendix C, line 66			(3.698)
9	AFUDC	Appendix C, line 66	-	1.3496	-
10	Return on Tree-trm Reg Asset	Appendix A, line 9			(7.062)
11	Return on Monroe Reg Asset	Appendix A, line 10			(1.253)
12	<b>Total Staff adjustments (rev. req. impact)</b>	Appendix A, line 11			<b>\$ (322.112)</b>
13	<b>Staff Revenue Deficiency (Initial Brief)</b>	Appendix A, line 10			<b>\$ 251.955</b>
<b>Walk from Staff Direct to Staff Initial Brief Revenue Deficiency</b>					<b>(million \$)</b>
14	<b>Staff Direct</b>	Direct, Schedule A-1			<b>\$ 247.371</b>
15	Rate base	See Below	75.526	6.95%	5.246
16	Depreciation	Appendix C, line 67			4.923
17	Property Tax	Appendix C, line 67			(0.803)
18	O&M	See Below			(4.782)
19	AFUDC	Appendix C, line 67	-	-	-
20	<b>Staff Initial Brief</b>				<b>\$ 251.955</b>
<b>Walk from Staff Direct O&amp;M to Staff Initial Brief O&amp;M</b>					<b>(\$000)</b>
21	<b>Staff Direct</b>	Direct, Schedule C1			<b>\$ 1,285,069</b>
22	Belle River Fuel Handling Post Natural Gas Conversion	Appendix C			1,950
23	Total Steam Power Generation - Inflation (Kindschy)	Appendix C			(2,039)
24	Total Fuel Supply & MERC Fuel Handling - Inflation (Ki)	Appendix C			(92)
25	Total Nuclear Power Generation - Inflation (Kindschy)	Appendix C			(1,354)
26	Total Hydraulic Power Generation - Inflation (Kindschy)	Appendix C			(131)
27	Total Other Power Generation - Inflation (Kindschy)	Appendix C			(295)
28	Total Distribution - Inflation (Rueckert)	Appendix C			(3,223)
29	Projects with level 3 cost estimates (Rogers)	Appendix C			402
30					-
31					-
32	<b>Staff Initial Brief</b>	Initial Brief, Appendix C, line 67			<b>\$ 1,280,288</b>
<b>Walk from Staff Initial Filing Rate Base to Staff Initial Brief Rate Base</b>					<b>(\$000)</b>
33	<b>Staff Direct</b>	Direct, Schedule B-1			<b>\$ 23,094,200</b>
34	Steam - Other - Trenton Channel BESS	Appendix E			(15,977)
35	Distribution Base Capital Customer Connections	Appendix E			14,430
36	Infrastructure and Modernization	Appendix E			45,030
37	Technology and Automation	Appendix E			32,662
38	Infrastructure Operations	Appendix E			4,287
39					-
40	Accumulated Deprecation	Appendix E			(4,907)
41	<b>Staff Initial Brief</b>	Initial Brief, Appendix B, line 16			<b>\$ 23,169,725</b>

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-21860**  
(e-file paperless)

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**PROOF OF SERVICE**

STATE OF MICHIGAN    )  
                                  ) ss  
COUNTY OF EATON    )

**Erin Fielder-Attia**, being first duly sworn, deposes and says that on **October 24, 2025**, she served a true copy of **Michigan Public Service Commission Staff's Initial Brief** upon the following parties **via email only**:

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Erin Fielder-Attia

Subscribed and sworn to before me  
this 24<sup>th</sup> day of **October, 2025**.

---

Cherie A. R. Shea, Notary Public  
State of Michigan, County of Jackson  
Acting in the County of Eaton  
My Commission Expires: 04-13-31