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January 9, 2026

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

RE: In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority
MPSC Case No. U-21860

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter is DTE Electric Company's Exceptions to the Proposal for Decision. Also attached is the Proof of Service.

Very truly yours,

Jon P. Christinidis

JPC/erb

Attachments
cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for authority to increase its rates, amend)
its rate schedules and rules governing the)
distribution and supply of electric energy,)
and for miscellaneous accounting authority)
_____)

Case No. U-21860

DTE ELECTRIC COMPANY'S EXCEPTIONS

TO THE PROPOSAL FOR DECISION

Dated: January 9, 2026

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I. INTRODUCTION

On December 22, 2025, the Administrative Law Judge (the ALJ) issued a Proposal for Decision (PFD) in this proceeding. DTE Electric Company (DTE Electric, DTE, or the Company) agrees with the PFD's recommended disposition of certain issues but takes exception to others. Therefore, the Company submits these exceptions. Lack of a discussion by DTE Electric to separately address every issue in the PFD should not be deemed to constitute an agreement by DTE Electric. Additional support for the Company's positions may be found in the Company's briefs, testimony, exhibits, and application, all of which are incorporated by reference in these exceptions.

II. EXECUTIVE SUMMARY

DTE Electric has initiated a major capital investment program to address localized demand growth, to replace and harden aging infrastructure to reduce outage frequency and duration, and to sustain the generation fleet while advancing projects that transition the Company's system towards cleaner energy consistent with the Commission's Integrated Resource Plan Order in Case No. U-21193. This rate case is a continuation of a multi-year effort to deliver high quality electric service to DTE Electric customers. However, as the Company's Application and the extensive record in this case demonstrate, the Company's current rates do not provide DTE Electric with adequate revenues to make the necessary infrastructure and generation investments and to maintain a position of financial health.

Nevertheless, many of the recommendations set forth in the PFD fail to give due weight to the evidence presented by the Company that substantiates its case. Through the testimony and exhibits of highly qualified and skilled Company employees as well as expertly credentialed witnesses, the Company has developed a robust record in support of its requests in this proceeding.

Through these exceptions the Company points out where the PFD fails to acknowledge or consider the evidence set forth by the Company and makes adjustments to the Company's requests, often in cases where the reasonableness and prudence of the expenditure is not in dispute. The Company is hopeful that the Commission will support the Company's ability to continue to maintain and improve service quality for its customers. The Commission should carefully review and thoughtfully weigh the evidence of record and ensure that the Company is in a position to continue to deliver value to its customers.

Michigan's Constitution requires Commission findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. Certain of the PFD's recommendations, if adopted by the Commission, would fail to satisfy this constitutional requirement. Despite the unprecedented depth of the record in this case, these recommendations often rest on conclusory assertions, minimizing or discounting entirely the evidence presented by the Company, or simply overlooking the practical consequences resulting from certain recommendations. Some of the most impactful examples of this are highlighted below.

For example, despite definitive evidence provided by the Company of escalating material and labor costs, the PFD recommended a disallowance of \$64.5 million in 2025 and \$66.5 million related to use of constant dollar averaging (CDA) as applied to Emergent Replacement capital spend, and \$12.044 million emergent O&M. In making this recommendation, the PFD minimizes or disregards the material cost increases demonstrated by the Company and outright neglects that contract labor rates, the primary expense related to storm response, have increased 30% since 2019. Instead, the PFD findings rely on an unrelated "downward trend" in costs for 2020 and 2022. The Company provided evidence that showed that this downward trend was due to a reduction in work volume and not material or labor costs, which are the subject of CDA. The PFD's minimization of

evidence provided by the Company results in a total revenue deficiency of \$23.9 million for emergent capital and O&M.

In addition, the PFD also recommends a disallowance of \$15.5 million for overheads associated with IT capital on the basis that the Company did not provide a method for applying these costs to future projects or sufficient detail regarding how it calculated the requested costs for existing projects. The PFD recognizes that overhead costs cannot be traced to a specific asset, yet still cited a lack of specific cost information as the basis for reduction. The Company provided evidence that overhead costs are expenses of a business that are not directly related to constructing an asset or providing a service. For example, overhead costs include AFUDC, banking and financing fees, mileage and commuting fees, miscellaneous materials from inventory, dues and assessments, utilities, investment recovery from scrap sales, lease and rent expense, meal allowances, office supplies, permits and licenses, postage, telecommunications, travel, and vehicles expenses. These are all necessary expenses to operate the Company and are not generated by particular projects. The PFD's disallowance for these necessary and routine items creates a \$2.6 million reduction in revenue deficiency.

The PFD also recommends a \$10 million disallowance of the Company's Payment Merchant Fee IT project capital costs amounting to \$2.6 million in revenue deficiency. In a prior decision involving DTE Gas, the Commission indicated that "it is not reasonable or prudent to socialize over the utility's customer base the merchant fees for customers who choose to pay by credit card." (Case No. U-21291 Order dated November 7, 2024, p. 158). Following this guidance, the Payment Merchant Fee project will allow the Company to directly pass through merchant fees to those customers who choose to use a debit or credit card to pay their bill. The practical effect of the PFD's recommended disallowance is to leave the Company in the unjustifiable position of

prohibiting its customers from using credit or debit cards, or being forced to absorb merchant fees on behalf of those customers who utilize their credit or debit cards to pay their bills.

Lastly, the PFD adopts a reduction in fuel handling expense for Belle River of \$3.5 million. This reduction is based on a presumption that converting one Belle River unit to gas obviates the need for 50% of the coal fuel handling equipment and labor, but this is simply not the case and disregards the operational reality that all units at the plant are supplied by a common system of conveyor belts that bring coal into the plant. Reducing the number of coal fired units does not reduce the labor and other O&M costs required to operate this common conveyor belt system, and the entirety of this expense remains necessary.

The highlighted disallowances above alone total \$32.6 million in reduced recovery for the Company, over half of which is unavoidable O&M expense. Beyond the fact that many of the PFD's recommended adjustments are unsupported by the record, if accepted by the Commission, these adjustments have the very real potential to impede the Company's core operations and hinder progress in the Company's multi-year journey to rebuild and reinforce its aged electric distribution grid and to invest in its power generation fleet.

As the record reflects, the Company requires rate relief for the projected test year to continue to provide service to its customers that aligns with the Commission's expectations for service quality.¹ A constructive outcome in this case positions the Company to sustain its pace of reliability-related improvements, to maintain access to capital at reasonable cost and on reasonable terms in spite of broader economic uncertainties, and to ensure that customer rates remain competitive.

¹ DTE Electric's updated projected revenue deficiency is approximately \$561.7 million. The Company's rate base for this case is approximately \$23.6 billion.

The Company is mindful of the impact to its customers of the necessary investments set forth in its filing, and has attempted to manage the pace of investment to moderate that impact. Rate relief consistent with the full extent of the Company's incremental revenue request would result in an increase of 44 cents per day for the average residential customer and an average yearly bill increase since 2021 of 2.6%, which is below the rate of inflation and below the average increases experienced at other utilities in the Great Lakes region and at the national level, as demonstrated by Company witness Bruzzano's Figure 1. (Bruzzano, 3T 975-976).

III. LEGAL STANDARDS

The PFD presents a "Legal Standards" discussion (PFD, pp 30-31) that is neither a finding of fact nor a conclusion of law, so DTE Electric need not take exception to preserve its rights. MAC R 792.10435. For convenience and brevity, however, DTE Electric collectively addresses certain matters to which it takes exception throughout the PFD.

The PFD (at p 30) correctly notes that DTE Electric is constitutionally protected from confiscatory rates, but neglects that the Company has additional constitutional protections. The Company maintains all of its constitutional rights that are presently involved or that might otherwise arise depending on how the Commission decides certain issues. Thus, the Company properly preserves constitutional issues but recognizes that "an agency exercising quasi-judicial power does not undertake the determination of constitutional questions or possess the power to hold statutes unconstitutional."²

DTE Electric's rights include due process rights under the Fourteenth Amendment to the United States Constitution. Michigan's Constitution similarly provides DTE Electric with the right

² *Wikman v Novi*, 413 Mich 617, 646-47; 322 NW2d 103 (1982). See also, *Taylor v Detroit Edison Co*, 475 Mich 109, 122; 715 NW2d 28 (2006) (MPSC lacked jurisdiction to decide constitutional issue, but had primary jurisdiction to decide case).

to fair and just treatment in MPSC proceedings: “No person shall be compelled in any criminal case to be a witness against himself, nor be deprived of life, liberty or property, without due process of law. The right of all individuals, firms, corporations and voluntary associations to fair and just treatment in the course of legislative and executive investigations and hearings shall not be infringed.” Const 1963, art 1, § 17.

DTE Electric further notes for background context on the subject raised by the PFD that it has constitutional protections against “takings” and confiscatory rates under the Fifth Amendment to the U.S. Constitution, which is applicable to the states through the Fourteenth Amendment. Similarly, Mich Const 1963, art 10, § 2 provides in part, “Private property shall not be taken for public use without just compensation therefore being first made or secured in a manner prescribed by law.” These constitutional protections have been recognized and applied to public utility rates in well-established case law.³ As a matter of fundamental ratemaking law, DTE Electric is entitled to a commensurate return of and on its investment in providing utility service.⁴

Michigan’s Constitution further requires that all Commission decisions must be authorized by law, and the Commission’s findings must “be supported by competent, material and substantial evidence on the whole record.” Const 1963, art 6, § 28. Substantial evidence is evidence “that a reasoning mind would accept as sufficient to support a conclusion.”⁵ Expert testimony is

³ See generally, *Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm of Missouri*, 262 US 276; 43 S Ct 544; 67 L Ed 981 (1923); *Federal Power Comm v Natural Gas Pipeline*, 315 US 575; 62 S Ct 736; 86 L Ed 1037 (1942); *Duquesne Light Co v Barasch*, 488 US 299; 109 S Ct 609; 102 L Ed 2d 646 (1989). See also, *Northern Michigan Water Co v Public Service Comm*, 381 Mich 340; 161 NW2d 584 (1968); *Consumers Power Co v Public Service Comm*, 415 Mich 134; 327 NW2d 875 (1982); *ABATE v Public Service Comm*, 430 Mich 33; 420 NW2d 81 (1988).

⁴ See *Bluefield Waterworks Improvement Co v Public Service Commission of West Virginia*, 262 US 679, 690-694; 43 S Ct 675; 67 L Ed 1176 (1923); *Federal Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944). See also *Permian Basin Area Rate Cases*, 390 US 747, 769-70; 88 S Ct 1344; 20 L Ed 2d 312 (1968); *FPC v Memphis Light, Gas and Water Division*, 411 US 458; 43 S Ct 1723; 36 L Ed 2d 426 (1973); *General Telephone Co v Public Service Comm*, 341 Mich 620; 67 NW2d 882 (1954); *Michigan Consolidated Gas Co v Public Service Comm*, 389 Mich 624; 209 NW2d 210 (1973).

⁵ *Monroe v State Employees’ Retirement Sys*, 293 Mich App 594, 607; 809 NW2d 453 (2011).

“substantial” only if it is offered by a qualified expert who has an informed and rational basis for his or her view.⁶

When reviewing a PFD in response to exceptions filed by a party, the Michigan Administrative Procedures Act (APA), MCL 24.201, *et seq.*, empowers the Commission to exercise all the power that it would have if it had presided at the hearing for cross-examination. MCL 24.281(3). Thus, the Commission retains the power to modify the PFD, so long as it does so based on the evidence in the record. Don LeDuc, *Michigan Administrative Law* § 6:69, at 478 (2d ed. Supp. 2010).

The PFD (at p 30) correctly notes that the preponderance of evidence standard applies in this proceeding. DTE Electric further notes and takes exception to the extent that the PFD applies a different standard or otherwise suggests that the Company’s requests for relief should be denied unless the Company overcomes some unstated (and unlawful) initial hurdle of evidentiary weight or other adverse presumption.⁷ Evidence also cannot be disregarded simply because it stands in the way of the decision-maker’s preference. Const 1963, art 6, § 28. The Commission also cannot draw inferences that are contrary to the undisputed record evidence. *White v Revere Copper & Brass, Inc*, 383 Mich 457, 462-63; 175 NW2d 774 (1970).

In *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), our Supreme Court explained: “The party alleging a fact to be true should suffer the consequences of a failure to prove the truth of that allegation.” Thus, unproven allegations cannot stand in the place of evidence. Things not

⁶ *Great Lakes Steel v Public Service Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983).

⁷ DTE Electric is also not required to continually re-prove things where some party(ies) indicate a continuing disagreement. Although res judicata and collateral estoppel do not apply in a strict sense to MPSC rate decisions, issues fully decided in earlier MPSC proceedings need not be completely relitigated in later proceedings unless the party wishing to do so establishes by new evidence or a showing of changed circumstances that the earlier result is unreasonable. *Application of Consumers Energy Co*, 291 Mich App 106, 122; 804 NW2d 574 (2010); *Pennwalt Corp v Public Service Comm*, 166 Mich App 1; 420 NW2d 156 (1988).

proven must be taken as not existing, since a decision cannot be based upon conjecture.⁸ The APA precludes the Commission from making decisions based on non-record materials. MCL 24.276 provides: “Evidence in a contested case... shall be offered and made part of the record. Other factual information or evidence shall not be considered in determination of the case except as permitted under [MCL 24.277 concerning official notice of judicially cognizable facts and facts within the agency’s specialized expertise].” Noncompliance with the APA is reversible error.⁹ It is similarly well established that an agency decision may not be based on speculation.¹⁰

Logistically, DTE Electric has the initial burden to prove its case by a preponderance of the evidence.¹¹ Other parties may challenge that evidence, but at that point the burden of proof shifts to the other parties. Thus, “once a utility has satisfied its initial burden of proof, another party ‘may challenge that evidence and present evidence of unreasonableness.’ However, at that point, the other party has the burden to demonstrate its position is correct.” October 25, 2017 Order in Case No. U-18224, pp 14-15, quoting January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, p 38. This evidentiary standard also effectively bars last-minute criticisms of the Company’s evidentiary presentation, as the Commission further explained:

The Commission finds that a delicate balance must be maintained concerning the burden of proof. The company has the burden of going forward and demonstrating

⁸ *Star Steel v USF&G*, 186 Mich App 475, 481; 465 NW2d 17 (1990).

⁹ *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002).

¹⁰ *Ludington Service Corp v Comm’r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), amended 444 Mich 1240 (1994) (unanimously reversing agency decision that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep’t of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency’s decision was not supported by evidence that a reasonable person would consider adequate).

¹¹ See generally, *Aquilina v General Motors Corp*, 403 Mich 206, 210-211; 267 NW2d 923 (1978) (“The proof required in an administrative proceeding... is the same as that required in a civil judicial proceeding: a preponderance of the evidence”). The “preponderance of the evidence” standard is generally defined as follows:

“**The greater weight of the evidence**, not necessarily established by the greater number of witnesses testifying to a fact but by evidence that has the most convincing force; **superior evidentiary weight that, though not sufficient to free the mind wholly from all reasonable doubt, is still sufficient to incline a fair and impartial mind to one side of the issue rather than the other.**” *Black’s Law Dictionary* 1301 (9th ed 2009). (Emphasis added).

that it has proposed just and reasonable rates. In this instance, Detroit Edison made that showing. The Staff in response may challenge that evidence and present evidence of unreasonableness. At that point, however, the Staff has the burden to demonstrate its position is correct. The company may then rebut the Staff's criticisms of its case. The problem here is that the specific criticism that the company had not adequately explained itself came too late in the process for a fair determination on that issue, particularly given the evidence the company presented in support of its position (January 11, 2010 Opinion and Order in case Nos. U-15768 and U-15751, pp 37-38).

Finally, for purposes of a collective general exception, DTE Electric notes that the PFD presents extensive findings and recommendations based upon its review of the record and at times may reach conclusions that, in themselves, do not cause the Company to be aggrieved, but which follow extensive discussions that are inaccurate or otherwise objectionable as beyond the scope of this case, beyond the proper scope of a PFD under MCL 24.281, that speculate concerning various matters, that increase the relevant burden of proof, or that ambiguously suggest the need for more evidence and/or further proceedings.¹² The Company further maintains that statutes must be applied as written,¹³ and controlling precedent must be followed.¹⁴

Company witness Uzenski explained that when a capital project will not be placed in service until after the projected test year, the project is carried in construction work in progress and the associated Allowance for Funds Used During Construction (AFUDC) is recorded as a credit to projected net operating income. As a result, if such a project is disallowed from rate base, there should be no impact on the Company's overall revenue requirement, because the AFUDC credit

¹² MCL 24.285 relevantly states: "A decision or order shall not be made except upon consideration of the record as a whole or a portion of the record as may be cited by any party to the proceeding and as supported by and in accordance with the competent, material, and substantial evidence."

¹³ See, for example, *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("we presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"); *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003) ("where the language of a statute is clear, it is not the role of the judiciary to second-guess a legislative policy choice; a court's constitutional obligation is to interpret, not rewrite, the law").

¹⁴ See, for example, MCL 7.215(C)(2) and (J)(1).

offsets the return that would otherwise be earned on that CWIP balance. Ms. Uzenski therefore testified that “any disallowances of capital projects going in-service beyond the projected test period should not have an impact on the revenue requirement because the cost is offset by an AFUDC credit in projected net operating income.” (Uzenski, 4T 2492, 2502)

These matters are further discussed below in the context of specific issues.

IV. DTE ELECTRIC HAS A \$561.7 MILLION REVENUE DEFICIENCY

As reflected below, the Company adjusted its initial forecasted revenue deficiency of \$562,632,000 by \$904,000 to reflect a revenue deficiency of approximately \$561,729,000 for the projected test year.

DTE Electric Company Revenue Deficiency Summary Projected 12 Month Period Ending December 31, 2026 (\$000)			MPSC Case No. U-21860 Reply Brief Attachment B
Line No.	(a) Description	(b) Source	(c) Revenue Deficiency (Pre Tax Amts)
1	Initial Brief Position	Exhibit A-11 Sch A-1	\$ 562,632
2			
3	Adjustments to Revenue Deficiency:		
4			
5			
6	Rate Base (1)		
7	Capital Expenditure, Increase/(Decrease)	Attachment A page 2	Rate Base Changes (11,399) (859)
8			
9	Working Capital, Increase/(Decrease)	Attachment A page 2	- -
10			
11	Operations and Maintenance Expenses		
12	O&M, Increase/(Decrease)	Attachment A page 3	(532)
13			
14	Depreciation and Amortization		
15	Depreciation Expense, Increase/(Decrease)	Attachment A page 3	280
16			
17	Property Tax Expense		
18	Property Tax Expense, Increase/(Decrease)	Attachment A page 3	207
19			
20	Total Adjustments to Company's Position	Line 7 through Line 18	\$ (904)
21			
22	Reply Brief Position	Line 1 + Line 20	<u>\$ 561,729</u>

(DTE Electric’s Reply Brief, Attachment B). The PFD recommends finding that the Company will have a revenue deficiency of approximately \$210.876 million in 2026 (PFD, pp 526, 682,

Appendix A). The PFD's recommended revenue deficiency is insufficient and must be increased based on the controlling law outlined above and in light of the record evidence supporting the Company's position. Attachment A to these Exceptions reflects the Company's position.

V. DTE ELECTRIC'S RATE BASE IS \$23.5 BILLION

A. Introduction

A utility's rate base is the value of the utility's property on which it is permitted to earn a specified rate of return. As this proceeding concludes, the Company has projected a total rate base of approximately \$23,515,626,000, (DTE Electric's Reply Brief, Attachment A, p 2), while Staff has projected a total rate base of \$23,160,941,000. (Staff's Reply Brief, Appendix B).

In this proceeding, consistent with its right established by MCL 460.6a(1), the Company has projected costs and revenues for a future consecutive 12-month period (calendar year 2026) in developing the rates and charges requested. Substantial record evidence supports a conclusion by the Commission that the Company's projections, and therefore its requested rates and charges, are just and reasonable. Because substantial competent evidence of record supports the Company's projections in this proceeding, the Commission need not resort to alternative projections and may, instead, rely on the evidence of record produced by the Company.

1. Contingency

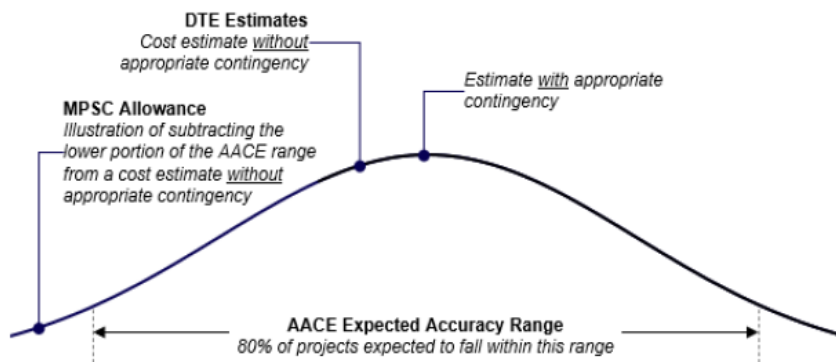
While the PFD focuses on the recovery of contingency, this was not an express request of the Company in this case. Consistent with the Commission's direction in previous cases, the Company did not include contingencies in its forecasts in this proceeding. (Robertson, 4T 2085). However, the Company's position is that it would be reasonable to include contingencies in its cost estimates, particularly where the Advancement of Cost Engineering (ACE) expected accuracy ranges are utilized as a proposed basis for cost disallowances because ACE does include contingency. (Robertson, 4T 2086).

In Case No. U-21534, Staff applied the ACE Expected Accuracy Ranges to the Company's estimates that exclude contingency and limited the allowance to the lower bound of the range, which effectively resulted in recovery of costs less than the lower bound of the ACE accuracy range. (Robertson, 4T 2090). The Company does not agree with the application of the ACE Expected Accuracy Ranges to its cost estimates for several reasons, including: (1) the use of a small sample size of project actuals as justification for anchoring a specific level of spend expectation is not aligned with ACE's recommended determination of accuracy ranges and does not replace the assessment of risk that ACE calls for to determine an appropriate range; and (2) prior Commission orders that cite use of ACE's Expected Accuracy Ranges, most recently in Case No. U-21534, do not reflect any consideration of the fact that ACE's Expected Accuracy Ranges include both a lower bound and an upper bound. (Robertson, 4T 2091). Instead, lower bounds appear to have been considered, in isolation, to justify disallowances. (Robertson, 4T 2091).

Because the Company's cost estimates do not include contingency, they already skew towards the lower half of the probability of outcomes distribution, and the subtraction of the lower

bound of AACE’s Expected Accuracy Range from a pre-contingency estimate (which is the effect of Staff’s recommendations) results in an allowance *below* the lower bound of AACE’s Expected Accuracy Range. This results in a situation in which there is less than 10% confidence of the Staff’s recommendations being sufficient to account for the full cost of the Company’s projects. (Robertson, 4T 2092-2093). The figure below illustrates this point.

Figure 3 MPSC Application of AACE Lower Bound Depiction



(Robertson, 4T 2093). Using the Company’s projections that already exclude contingency as the baseline with which to determine a range of expected project costs is inconsistent with AACE Recommended Practices. (Robertson, 4T 2093). In its January 23, 2025 Order in Case No. U-21534, the Commission acknowledged that confidence intervals intended for use on estimates that include contingency were applied to the Company’s project estimates, which do not include contingency. The Commission, however, failed to apply those confidence intervals in a manner consistent with AACE Recommended Practices, which should consider inclusion, or lack thereof, of contingency. (Robertson, 4T 2094). AACE ranges should not be considered as a “general guide” as they attempt to account for variable risk – not contingency – and, therefore, should not be interpreted as recommended adjustments. (Robertson, 4T 2094). If the Commission continues to

accept the use of the AACE ranges, then contingency estimates should be explicitly allowed in the Company's forecasts. (Robertson, 4T 2095). As testified to by Company witness Robertson, the use of a contingency is a best practice in utility cost estimation, as recognized by the U.S. Department of Energy, the Project Management Institute, AACE International, and is accepted by other jurisdictions including Indiana, Minnesota, and Ohio. (Robertson, 4T 2099-2102).

The PFD incorrectly surmises that the Company has abandoned the issue, (PFD, p 41), which is not the case. While acknowledging the substantial evidence provided by Company witness Robertson, the PFD dismisses the Company's evidence and suggests only that the Company may include any disallowed costs in a subsequent rate case. The PFD then summarily concludes that the Company has not presented a sufficient reason for the Commission to deviate from its stance that contingency should not be included. (PFD, pp 40- 41).

The PFD's assertion that the Company is at no articulated risk for delay in seeking recovery of actual costs is incorrect (PFD p. 41). In fact, Mr. Bruzzano testified that even if the investment is ultimately included in rate base through a subsequent rate case, the Company cannot recover any of the costs it incurred between the time it made the investment and when the investment was approved to be recovered. For example, the Company cannot recover any cash interest expense or property taxes that it paid in support of an investment prior to the investment being approved for recovery, and a portion of the cash cost of the investment will also not be recovered because of the foregone depreciation expense. Thus, the regulatory lag associated with disallowance of otherwise reasonable and prudent investments does result in lost recovery. (Bruzzano, 3T 979).

Company witness Bruzzano also highlighted that the capital disallowances that resulted from the application of the AACE ranges in Case No. U-21534 were significant and included approximately \$185 million worth of 2024 investments. The Company's expenses were slightly

above the Company's 2024 projection in that case and the costs associated with the \$185 million disallowance (which was invested) will not be recoverable. (Bruzzano 3T 979-980) In this case, the PFD recommends \$25M in disallowances based on the AACE ranges for Level 2 and Level 3 IT projects. The types of disallowances associated with the AACE disallowances are especially concerning because the Company has no choice but to incur the costs as they occur and cannot simply pause to recover the remaining 10% to 20% of costs disallowed due to AACE. (Bruzzano, 3T 983).

The financial pressures created by these disallowances and the resulting regulatory lag force action on the part of the Company to maintain its financial health and access capital on reasonable terms. (Bruzzano, 3T 989). Additionally, As the Company continues its multi-year journey to rebuild and reinforce its aged electric distribution grid and to invest in its power generation fleet, the Company and its customers are best served by timely recovery for the investments in its system that are needed to maintain and enhance reliability. The Company stands by its position for the reasons articulated above and respectfully requests that the Commission reconsider the application of the AACE ranges as a basis for capital disallowance as further discussed in Section V.G.2 below.

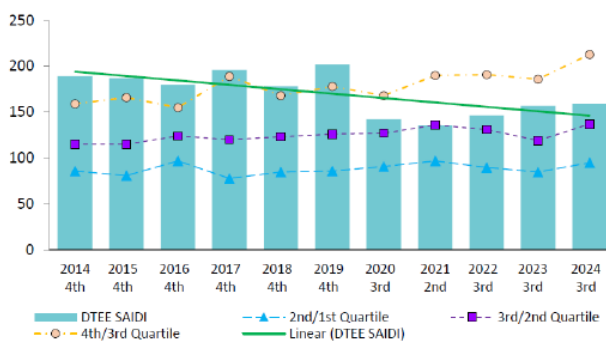
2. Capital Expenditures and Increase in Rate Base

The PFD notes that several parties allege significant increases in rate base without corresponding improvements in reliability and that the increases in rate base outpace historical levels of investment by the Company. (PFD, p 41). The PFD acknowledges these AG and MNAG positions and addresses them topically. (PFD, pp 43-44).

However, the evidence of record simply does not support these parties' contentions, particularly with respect to the performance of DTE Electric. A combination of the reliability-

focused capital improvements and less extreme weather resulted in a nearly 70% decrease in outage duration times between 2023 and 2024. (Chiu, 3T 1135). Moreover, electric outages decreased by 14% and the amount of time customers were without power decreased by 38% in 2024 compared to the five-year average (2019 to 2023). This fact is corroborated by CEO Witness Volkmann. (Volkmann, 4T 3648). Evidence in the record demonstrates that the Company’s SAIDI excluding major event day (SAIDI Ex-MED) data for the years 2015 through 2024 reflects that the Company has improved in its reliability quartile ranking over that period of time. (DTE Electric’s Reply Brief, p 31). The figure below, from Company witness Chiu’s rebuttal testimony, presents the Company’s SAIDI Ex-MEDs data for the years 2014 through 2024 and includes quartile rankings from the Institute of Electrical and Electronics Engineers (IEEE) reliability benchmark surveys based on standardized reliability metrics across utilities. These data reflect an improving trend in the Company’s reliability performance and support the conclusion that the Company’s strategic capital investments have yielded measurable reliability improvements.

Figure 1 – SAIDI Ex-MED Performance (Minutes)⁷



(Chiu, 3T 1136-1137). Additionally, DTE Electric’s SAIFI performance has consistently ranked in the second quartile for SAIFI Ex-MED and for SAIFI All-Weather has ranked second or third quartile, based on IEEE industry benchmarking. (Chiu, 3T 1138). This broader

benchmarking comparison provides a more realistic and balanced view of the Company's reliability performance. (Chiu, 3T 1138). The evidence of record in this proceeding supports the Company's position both in terms of reliability performance and the reasonableness and prudence of the proposed investments. In this case, in addition to using data driven analytics to develop certain programs and prioritize investment, the Company also performed benefit cost analyses (as many intervenors have long requested the Company to do) on certain programs to ensure that its proposed investments will produce benefits that exceed costs. The Commission should not be persuaded by the unsubstantiated or erroneous claims of these parties and instead should rely, when making its decisions, on the substantial evidence of record that supports the Company's positions.

B. Production Plant (non-nuclear)

1. Trenton Channel Seawall and Greenway

Company witness Guillaumin explained that this is a project to restore the integrity of the seawall at the Trenton Channel Power Plant and to install a pedestrian greenway path along the Detroit River required to meet the permitting requirements of the US Army Corps of Engineers, Michigan Department of Environment, Great Lakes and Energy (EGLE), and the City of Trenton. From 2023 to the beginning of 2025, \$0.9 million was spent to begin engineering and design of the seawall, natural shoreline, and greenway path. In 2026, \$9.5 million is projected to be spent to complete engineering, design, and construction of the seawall for the riverfront and canal and complete engineering and design of the greenway path. (Guillaumin, 3T 579-580; Exhibit A-12, Schedule B5.1, page 2, line 25).

ABATE witness York and AG witness Coppola argued that the Company's proposed \$9.456 million 2026 test year capital for the Trenton Channel Seawall and Greenway

project should be excluded as insufficiently supported. The AG argued that only an initial \$1.1 million appropriation exists, that the projects remain in early design, and lack full internal capital approval. (AG Revised Initial Brief, pp 48-50). ABATE points to a document showing negative \$285,000 capital spending for January-May 2025 (Exhibit AB-7) to support an asserted lack of additional internal review or approval (PFD, p 46) and argues that the Company has not demonstrated that the proposed investment is likely to be made during the bridge period or projected test year. Both the AG and ABATE allege that the 2026 Seawall and Greenway expenditures are speculative and recommended removal of the \$9.456 million from the test year capital forecast. (PFD, pp 46-48).

The PFD erroneously accepted these concerns and recommended disallowance of the full \$9.456 million 2026 test-year amount. After recounting the Company's evidence that approximately \$0.9 million had already been spent on engineering and design and that full project completion is planned for 2027, the PFD relied on the Commission's statements in Case No. U-21534 that projected costs must be both objectively reasonable and likely to be incurred during the test year to be recoverable. (PFD, p 49 citing Case No. U-21534 Order dated January 23, 2025, p 52). The PFD concluded that, while it is reasonable to approve the smaller \$0.514 million bridge-period amount to allow planning and engineering to continue, DTE Electric "has not provided the documentation of progress required by the Commission in U-21534" for the \$9.456 million and recommended its exclusion from rate base "because, lacking internal approvals, it is not likely to be spent during the test year." (PFD, p 49).

The Company disagrees as it has provided competent, material, and substantial evidence to the contrary by a Company expert witness. Company witness Guillaumin provided the evidence necessary to support recovery of Trenton Channel Seawall and Greenway costs, and the PFD gives

no record-based reason to conclude that the planned 2026 test-year expenditures are not likely to be incurred during the projected test period. The Company has explained that it has a signed \$1.1 million appropriation request for the Trenton Channel Seawall project covering engineering and design of the future site which was produced in discovery and is included in the record as ABATE Exhibit AB8. (Guillaumin, 3T 709) As engineering and design work has been fully funded, Company witness Guillaumin explained that an appropriation request that includes the full project budget will be executed once the design and engineering are complete. It is also uncontroverted that the seawall work is necessary to restore sections to a safe condition for pedestrian use and is a required component of the City of Trenton permit tied to decommissioning the Trenton Channel Power Plant. (Guillaumin, 3T 709). Company witness Guillaumin testified that the project “is progressing as planned” and that there is “no reason to expect that the Trenton Channel Seawall project will not be completed.” (Guillaumin, 3T 709) On this record, the PFD’s conclusion that DTE Electric “has not provided the documentation of progress required by the Commission in U21534” and that the \$9.456 million is “not likely to be spent during the test year” is unfounded and rests on speculation and assumptions that are contradicted by direct evidence from the Company’s expert witness in the record about the project’s planning and status. The record reasonably demonstrates that the project is a “worthwhile investment[] . . . [that] is likely to be made during the [projected test period] [.]” See Case No. U-21534 Order dated January 23, 2025, p 52. Accordingly, the Commission should reject the PFD’s recommendation to disallow the \$9.456 million 2026 Trenton Channel Seawall and Greenway capital expenditure and instead approve the Company’s requested recovery as a reasonable, prudently supported, and timely component of the Trenton Channel Power Plant decommissioning.

2. Monroe Fly Ash Basin Closure

Company witness Guillaumin testified that this is a project to permanently close the fly ash wet basin at the Monroe Power Plant, as required by federal and state regulations. In 2023, \$3.8 million was spent to begin engineering and design. In 2024, \$4.8 million was spent to continue engineering and design and develop a request for proposal to perform the basin closure. In 2025, \$13.9 million is projected to award the ash basin closure construction contract and begin project construction. In 2026, \$107.8 million is projected to be spent for on-site activities including dewatering the 410-acre pond, mass grading, material delivery, and liner cap and synthetic turf installation. (Guillaumin, 3T 572-574; Exhibit A-12, Schedule B5.1, page 2, lines 19 and 46).

The PFD adopts the AG's recommendation to disallow \$53.88 million, or effectively half of the Company's \$107.8 million 2026 forecasted capital related to closure of the Monroe Fly Ash Basin, based on the view that the Company's implementation plan is still being finalized, contractors have not yet been selected, and full Board of Director-level approvals are not yet in hand, making it "unlikely the Company will spend the bulk of the projected \$107.8 million in 2026." (PFD, p 53). That conclusion is contrary to the evidence in the record and therefore cannot satisfy the Commission's obligation to base its decision on competent, material, and substantial evidence.

The Company has shown that closure of the Monroe Fly Ash Basin is a mandatory environmental compliance project, required "to comply with federal and state environmental regulations." (Guillaumin, 3T 707). As acknowledged by the PFD, the Company has already incurred \$3.8 million in 2023 and \$4.8 million in 2024 on engineering, design, and RFP development, issued the closure RFP in October 2024 with bids received in December 2024, and projects \$13.9 million in 2025 spending to award the closure contract and mobilize construction,

followed by \$107.8 million in 2026 for dewatering the 410-acre pond, mass grading, material delivery, and liner cap and synthetic turf installation. (PFD, p 50; Guillaumin, 3T 573-574). Company witness Guillaumin testified that management has already approved funds to proceed with the work as scheduled, emphasizing that “the scale of work required to meet regulatory requirements necessitates the full investment be included in 2026 and there is little doubt that the project must be completed.” (Guillaumin, 3T 707-709). The PFD unreasonably discounts Company witness Guillaumin’s rebuttal testimony confirming “[f]ull project completion is currently scheduled for 2027” and makes a generalized assertion that Company witness Lee’s “testimony regarding the timeline for the project and closure of the fly ash basin bolster [the PFD’s] conclusion” but points to nothing specific. (PFD, pp 53-54).

On this record, there is no evidence that the Monroe Fly Ash Basin closure is unnecessary or not likely to proceed on the schedule DTE Electric has presented. The PFD’s recommendation to disallow “half” of the 2026 closure spend is arbitrary and rests on the absence of final Board approval and contractor selection, rather than on any contrary evidence regarding the project’s regulatory mandate, planned schedule, or the multi-year spending already underway. The Commission should therefore reject the recommended \$53.88 million disallowance and approve inclusion of the full 2026 Monroe Fly Ash Basin Closure investment in the regulatory asset as a reasonable and prudently supported compliance cost. (Guillaumin, 3T 572-574; Exhibit A-12, Schedule B5.1, page 2, lines 19 and 46).

3. Routine Projects

The AG recommends removing \$63.7 million in forecasted 2026 capital for five routine generation projects. Specifically, he recommends disallowance of: (1) \$6.9 million for the Monroe Unit 1 SCR Catalyst Layers 1, 2, and 4; (2) \$22.9 million for the CTG11 Hot Gas Path Overhaul;

(3) \$23.8 million for the CTG12 Hot Gas Path Overhaul; (4) \$6.3 million for the BWEC Steam Turbine Valves; and (5) \$3.8 million for the Renaissance Unit 3 Peaker Combustion Overhaul. (AG Revised Initial Brief, pp 53-55; Coppola Exhibit AG-12, page 1). The AG in its Initial Brief also inaccurately asserts that the Company “failed to provide full information” in testimony and a discovery response regarding the routine projects and urges the Commission to “hold DTE to a higher standard of support” by disallowing the entire \$63.7 million. (AG Revised Initial Brief, pp 54-55, Exhibit AG-74, p 1, AGDE-12.345; PFD, pp 67-68).

The PFD adopts the AG’s position, finding that Exhibit AG-12 “does not provide the level of detail requested” and concludes that the more detailed project documentation DTE Electric provided in Exhibit A-54, Schedule UU5 was “provided too late in this proceeding for the AG or other parties to evaluate.” (PFD, p 69). Therefore, the PFD recommends disallowing the full \$63.7 million for these routine projects, or alternatively recommends the Commission impose a disallowance aligned with Staff’s treatment of IT projects with similar Association for the Advancement of Cost Engineering (AACE) classifications. (PFD, pp 68-69).

The Company disagrees and maintains that the record demonstrates these are specific, routine, and timely maintenance and reliability projects, and are not speculative projects. As supported by witness Guillaumin’s testimony (3T 698-702) and addressed in DTE Electric’s Initial Brief (pp 38-40), these are well-defined, fully approved, and scheduled maintenance and reliability projects with concrete support: most already have negotiated contracts in place (Renaissance 3, BWEC CTG11/CTG12 hot gas paths, and BWEC steam turbine valves), and materials for the BWEC work have been ordered or are in inventory. Monroe Unit 1 SCR catalyst replacement is routine environmental compliance performed during planned outages to maintain required NOx reductions under air permits. The BWEC hot gas path overhauls, while first-time at BWEC, mirror

peaker overhauls the Company has executed before and proceed under the existing OEM long-term service agreement that sets timing, scope, and pricing – leaving only Company labor/support as residual cost. The BWEC steam turbine valve work, also first-time at BWEC, is a standard safety activity the Company has performed for decades at other plants with a well-understood scope and cost. The Renaissance Unit 3 combustion overhaul is standard peaker maintenance: the Company has completed more than ten similar inspections/replacements since 2016, negotiated portfolio pricing in 2024 for upcoming events across all four units, and completed overhauls on Units 2 and 4 in 2025. On this record, project details include full internal approvals, defined scopes grounded in historical actuals or vendor/OEM proposals, awarded contracts, and schedules already underway; there is no reasonable basis to deem these projects preliminary or uncertain.

With respect to the PFD’s conclusion that the Company “does not provide the level of detail requested” by the AG, the PFD provides no support for the proposition. Exhibit AG-12 (containing Company discovery responses) provides the following narrative response that references a two-page spreadsheet full of the Energy Supply generation project data requested:

“Question: 110. Refer to Exhibit A-12, Schedule B5.1, pages 6 and 7. For 2025 and 2026 and for each project of \$3 million or greater; please: a. Provide the current phase of project development (ie. Preliminary Assessment, Conceptual Design, Engineering Design, Construction, Completed, etc.) and the completion and in-service month and year.

Answer: Please see attachment labelled ‘U-21860 AGDE-3.110a Routine \$3M+’. The ‘Current Phase of Development was determined based on Table 1 of my direct testimony on page 19.

Attachment: U-21860 AGDE-3110a Routine \$3M+” (Exhibit AG-12 pp. 2-3)

The Company’s discovery response is clearly responsive to the request (at a bare minimum a reasonable, good faith attempt to be responsive) and the PFD, in any event, does not explain its contrary conclusion other than to note differences in how Company witness Guillaumin described

project phases in both her direct testimony (Guillaumin, 3T 555) and in what became Exhibit AG-12 (despite the question itself disregarding the Company's phase descriptions and using a vague "etc." in relation to what might have been intended) -- nor why it might justify a large \$63.7 million recommended disallowance.

The PFD's focus on the timing of submitting one rebuttal exhibit (Exhibit A-54, Schedule UU5), most of which was previously available to the AG for months as workpapers with the initial filing of the instant case, should not undercut the substantial support DTE Electric has provided in testimony, exhibits, and workpapers. In addition to the erroneous conclusion that the Company's evidence was "provided too late in this proceeding for the AG or other parties to evaluate" (PFD, p 69), it is also procedurally inappropriate to summarily conclude that rebuttal evidence is "too late." (See generally MCL 24.272(4) of the Michigan Administrative Procedures Act "*A party may submit rebuttal evidence.*"; R 792.10427 of the Rules of Practice and Procedure Before the Commission "*A party shall have the right of cross-examination and shall have the right to submit rebuttal evidence.*") Additionally, the Commission can rely upon any evidence of record in arriving at its decision and the AG had full opportunity to evaluate the accuracy of Exhibit A-54, Schedule UU5 at the hearing. Moreover, the PFD's alternative recommendation to "consider a disallowance consistent with Staff adjustments for IT Projects with equivalent AACE estimates" is notably not supported by the AG, Staff, nor any record evidence in this proceeding. The Commission should therefore reject the PFD's recommended \$63.7 million disallowance for these five routine projects and approve recovery of the associated 2026 capital as reasonable and properly supported.

C. Nuclear Production

Company witness Davis testified in support of investments that are necessary to properly maintain the Fermi 2 asset. (Davis, 3T 420-421; Exhibit A-12, Schedule B5.3; Exhibit A-20,

Schedule J2). For the historical test year, for the 24-month bridge forecast period ending December 31, 2025, and for the 12-month projected test period ending December 31, 2026, the capital investment totals \$264.0 million, \$399.6 million and \$187.4 million respectively. (Davis, 3T 421; Exhibit A-12, Schedule B5.3, page 4). He testified in support of the proposed investments, depicted by line 11 of Exhibit A-12, Schedule B5.3, page 1, and indicated that they accurately represent the capital expenditures that can reasonably be expected to continue operation of nuclear assets of similar age and vintage. He testified that the proposed capital projects reflect DTE Electric's commitment to ensure the safe and reliable operation of Fermi 2 through its current operating license expiration in 2045 and that the capital expenditures are prudent and reasonable given the regulations, goals and conditions under which Fermi 2 operates. (Davis, 3T 486).

Company witness Davis also testified that the Company's Case No. U-21534 projected Nuclear Generation capital expenditures were \$266.7 million for the 12-month period ending December 31, 2023 and that actual Nuclear Generation capital expenditures for the same period were \$264.0 million. The total variance is approximately 1.0% of projected total Nuclear Generation capital expenditures for the referenced period, which is representative of historical variance for Nuclear Generation capital expenditures. (Davis, 3T 421).

The PFD notes that the Commission has consistently conducted its review of nuclear production capital expenses on a project-by-project basis¹⁵ and generally recommends adoption of the nuclear production capital expenditures sought by the Company except for the limited recommended project disallowances discussed below in this Section. (PFD, p 71). The Company

¹⁵ Despite the Company's explanation that DTE Electric manages Nuclear Generation in the aggregate to complete scopes of work consistent with the nuclear safety priority (Davis, 3T 528) and evidence (for example, roughly 99% expenditure alignment to projections in 2023, Davis 3T 421) that DTE Electric nuclear operations are best reviewed in totality on an annualized basis.

takes no issue with the PFD's general recommendation for approval of the Company's nuclear production capital expenditures. The Company's exceptions to the PFD's limited recommended project-based disallowances are discussed below.

1. Routine Nuclear Projects

AG witness Coppola took issue with three routine nuclear capital projects initially presented by Company witness Davis—(1) document management system enhancements; (2) reactor recirculation system (RRS) replacements; and (3) natural draft cooling towers—arguing that these projects are premature for inclusion in base rates because they remain in an early stage of development with some costs falling outside of the projected test year. (Coppola, 4T 3468; Davis 3T 520-523). The PFD found that DTE Electric sufficiently supported the need and timing for the cooling tower project, but recommends the Commission adopt the AG's proposed disallowance of \$14,682,000 for the document management system enhancements and RRS replacements. (PFD, p 82). To support this recommendation, the PFD states that DTE Electric has not established when the expenditures will actually be incurred and notes DTE Electric's acknowledgment that disallowance of these expenditures will not impact the Company's revenue requirement. (PFD, p 82).

The Company takes no exception to the PFD's recommended approval of expenses related to the cooling tower project but disagrees with the PFD's finding that DTE Electric "has not established when the expenditures [for document management system enhancements and RRS replacements] will actually be incurred." (PFD, p 82). Notably, the PFD does not dispute that DTE Electric has sufficiently explained the need for the document management system enhancements or RRS replacements. While it is true that the in-service date for these projects falls outside the test year, the timing for their implementation is not uncertain or speculative. As Company witness

Davis explained in his rebuttal testimony, the document management system enhancement project will be complete in 2028 and the RRS replacements project will be complete in 2027. (Davis, 3T 519; Exhibit A-12, Schedule B5.3, p 2-4). These multi-year projects are appropriate for inclusion in base rates when the Company has determined the need to initiate them, provided that proper accounting and ratemaking treatment is applied. While these projects do not impact revenue requirements in this case, they are necessary, well-justified expenditures incurred as part of the Company's commitment to nuclear safety and maintaining long-term reliability at the Fermi 2 Power Plan. (Davis, 3T 519-520; DTE Electric's Reply Brief, p 73) Accordingly, the Company maintains that the Commission should affirm the appropriateness of these expenses for accounting and ratemaking purposes and reject the AG's proposed disallowances.

2. Non-routine Nuclear Projects

AG witness Coppola recommended disallowance of expenses related to three non-routine nuclear capital projects initially presented by Company witness Davis—(1) turbine controls replacements; (2) reactor recirculation motor-generator (RRMG) replacements, and (3) circulating water (CW) traveling screens—arguing that inclusion of these projects in rate base is premature because the projects have not yet commenced and are planned to be placed in service beyond of the projected test year. (Coppola, 4T p 3468). While the PFD affirmed the need for the projects to maintain nuclear security and safety, it adopts the AG's proposed disallowance of \$8,742,000 for 2025 and \$28,298,000 for 2026, noting that the earliest in-service date for these three projects is 2027. (PFD, p 86). According to the PFD, parties may request more information regarding the date of purchase for essential components of these projects in a future rate case.

The Company disagrees and maintains that the record demonstrates these non-routine nuclear projects are specific and timely maintenance and reliability projects and are not speculative

projects. Like the routine nuclear projects discussed above, these multi-year projects are appropriate for inclusion in base rates when the Company has determined the need to initiate them, provided that proper accounting and ratemaking treatment is applied. Here, as explained by witness Davis, the Company has determined that these projects will be initiated in the test year and the Company will incur costs and pursue the projects as presented in Exhibit A-12, Schedule B5.3, p 2-4. Accordingly, the Company maintains that the Commission should affirm the appropriateness of these expenses for accounting and ratemaking purposes and reject the AG's proposed disallowances recommended by the PFD.

3. Underground Water Piping Replacement

The PFD adopts the AG's recommendation to disallow \$12.6 million related to the Underground Water Piping Replacement Project, finding that the source of the expense is "elusive." (PFD, p 90).¹⁶ The Company disagrees and takes exception with this characterization of the expense as DTE Electric has explained the source of this expense many times over in the Rebuttal Testimony of Company witness Davis, through responses to discovery requests, and again in the Company's Reply Brief. This multi-year Underground Water Piping project started in 2014 and has been discussed, reviewed and approved within prior Case Nos. U-20162, U-20561, U-20836, U-21297, and U-21534. To reiterate, the Company's original Underground Water Piping Replacement internal project authorization of \$58.8 million was incomplete as it only accounted for activities that the project had direct control over and did not account for activities and resources managed at the site level which are used on many projects (e.g. radiation protection). As site level

¹⁶ The PFD also mistakenly reviews a different project in reaching its erroneous conclusions. "Interestingly, in Case No. U-21534, the RHRSW had only \$974,000 spend in Exhibit A-12, Sched. B5.3, page 2, line 27, for the 2022 historical year." (PFD, p. 90) The RHRSW project referenced by the PFD is a pump replacement project and not the underground pipe replacement project at issue here.

resources are identified as necessary, they are allocated to and accounted for among the appropriate Company departments and across the specific projects that utilize these shared resources. Company witness Davis explained in his direct testimony that total 2024 Nuclear Generation capital expenditures were within 2.2% of the total projected 2024 capital expenditures depicted in Case No. U-21534, Exhibit A-12, Schedule B5.3. (Davis, 3T, 424-425) Accordingly, approximately \$21.0 million of the Company's approved cost estimate change (of which \$12.6 million was identified as the contested "Outage Shared Cost" with the notation "MEP to Fermi Capital.") resulted in no overall change to the Nuclear Generation total capital expenditures because it simply reallocated certain shared capital expenditures to the appropriate project level. (Davis, 3T 526).

The Company completed and placed Underground safety-related service water piping project in-service following the Fermi 2 Refueling Outage 22 in spring of 2024 (Davis, 3T 459). As Company witness Davis explained, the \$12.6 million "Outage Shared Cost" expenditure was not additional or incremental; it was simply a proper allocation of an expected, reasonable, and prudent expense. (Davis, 3T 527-528). For these reasons, the Commission should reject the proposed \$12.6 million disallowance and approve inclusion of the full expense for the Underground Water Piping Replacement project in the regulatory asset as a reasonable and prudently supported compliance cost.

At bottom, the confusion of an external witness concerning a shorthand notation in a Company internal form disclosed in discovery would be an arbitrary and unreasonable basis to disallow a necessary, reasonable, and prudent expense. It is unremarkable that every internal Company document and every rate case exhibit does not neatly and universally tie. For example, although project management may include contingencies, they have been excluded from rate case

requests. (Davis, 3T 479-480) Furthermore, as Company witness Davis explained, “Nuclear Generation manages total capital expenditures for the period and expects that expenditures in total will be incurred as projected.” (Davis, 3T 480) These circumstances, multi-year projects, changing rate case filing requirements, and the allocations of expenditures within the Company explained above, are among the many reasonable and legitimate reasons why an external witness faced with thousands of documents might be confused. Such confusion is, nevertheless, no good reason to reject proper cost recovery – especially for a project that the Company completed and placed in-service within the amounts and schedule the Commission previously reviewed and authorized for recovery in the two immediate prior Case Nos. U-21297 and U-21534.

D. Distribution

1. Background

The Company operates one of the oldest electric distribution grids in the country, and that system is showing its age. The system is composed of aged lines and equipment that create capacity constraints, pose safety and operational challenges, and impede efficient restoration during outages. (Chiu, 3T 1088). In line with its plan for significant and sustained investment in the distribution system, the Company invested \$1.6 billion for the historical 12-month period ending December 31, 2023 and is requesting \$3.2 billion of capital investments for the 24-month period ending December 31, 2025, and \$1.9 billion of capital investments for the 12-month projected test year ending December 31, 2026. (Chiu, 3T 1090). The Company’s investments in its distribution system fall into two broad categories: (1) Base Capital, which supports the necessary and critical set of investments that are responsive to emergent or specific customer needs including Customer Connections, Relocations, Others, and the Emergent Replacements for Storm, Non-Storm, and Substation Reactive programs; and (2) Strategic Capital, which is intended to align with the

Commission's directives and the findings of the Liberty Audit and is driven by the Company's strategy of delivering near-term reliability improvements while undertaking, over the longer term, more extensive rebuilds for certain portions of the grid. (Chiu, 3T 1090-1091).

2. Inflation

In this proceeding, consistent with previous rate case proceedings, the Company proposed a blended inflation rate, which relies on the CPI-U for a non-labor inflation factor and on a labor factor that is tailored to reflect the Company's actual labor costs. (Fix, 3T 1472). The Company's proposed blended inflation rates are 3.40%, 3.00%, and 3.10% for 2024, 2025, and 2026, respectively. These rates are applied to O&M and capital expenditures. (Uzenski, 4T 2424).

The PFD recommends that the Commission adopt the updated CPI-U inflation rates of 2.9% for 2024, 2.7% for 2025 and 2.4% for 2026, which the PFD asserts include wage inflation. (PFD, p 102).

While the Company agrees, in part, with the PFD's use of the CPI-U inflation data, the Company does not agree with the PFD's rejection of the labor component of the Company's proposed composite inflation rates. For this reason, the Company respectfully requests that the Commission accept, as it has done in its previous rate case orders, the Company's composite inflation rates, which are specifically tailored to reflect costs that the Company actually incurs.

In its January 23, 2025 Order in Case No. U-21534, the Commission approved the Company's blended inflation rates, stating that its approval was consistent with prior orders and that:

DTE Electric provided evidence that the composite inflation rate "separates labor inflation, which is subject to Company-specific dynamics like collective bargaining agreements, from non-labor inflation. DTE Electric's witness also noted that the company and the Attorney General used the same CPI-Urban (CPI-U) rate for non-labor costs, with the only difference being the source document. On this record, the Commission approves the use of the blended rate, and directs DTE Electric, in its

next rate case, to provide further detail on the company-specific dynamics that justify rejection of the CPI-U or a similar widely-used rate for labor costs.

Case No. U-21534 Order dated January 23, 2025, pp 74-75. In so ruling, the Commission rejected Staff's and the AG's recommended use of the Consumer Price Index All Urban (CPI-U), without any company-specific adjustment for labor inflation. Case No. U-21534 Order dated January 23, 2025, pp 213-214. In addition, the Commission rejected the proposal by MNSC to offset inflation by applying a labor productivity factor. Case No. U-21534 Order dated January 23, 2023, pp 212-214.

In this case, MNSC, the AG and ABATE have recycled the same arguments, and the Commission should again not give these arguments weight.

Through the testimony of Company witness Fix, the Company provided detail on the Company-specific dynamics that justify rejection of the CPI-U or a similar rate for labor costs.

As testified to by witness Fix:

Annual labor cost escalation assumptions are required for both the Company's represented and non-represented employees. Based on existing Collective Bargaining Agreements, the Company is obligated to increase pay rates by at least 3% annually through the term of the contracts. In addition to scheduled pay rate increases, the agreements also provide for progression increases for those employees that have not yet achieved the maximum pay rate for their positions.

(Fix, 3T 1472). Company witness Fix testified that all non-represented non-management employees received an overall pay increase of 3% in 2023, which was comparable to the annual pay adjustments in every year since 2010. He testified that in addition to the annual pay adjustment program, employees generally receive pay increases based on promotions and that in March of 2024 and March of 2025, the Company implemented an annual Base Pay Review for its non-represented employees that provided for average annual pay increases of 3.5% and 3.0%, respectively. (Fix, 3T 1472).

Company witness Fix also testified that NRDC-CUB witness Bunch's recommended labor inflation for 2024 of 0.23% based on his calculation of the Company's compound average growth in total compensation costs for the period 2019 through 2024 of 0.23% is flawed and if calculated to exclude incentive compensation and employee benefits, the compound annual growth rate would be 3.27%, as reflected on Exhibit A-55, Schedule VV2, line 27, column (j). (Fix, 3T 1520). For these reasons, the Commission, like the PFD, should give no weight to the labor inflation component as proposed by NRDC-CUB witness Bunch. (PFD, p 102).

While the AG argues, and the Company acknowledges, that the CPI-U inflation rate includes a labor component, the Company stands by its proposal to use a composite inflation rate that reflects its actual labor cost. Specifically, in response to a discovery request from the AG, the Company explained that for employees not under a collective bargaining contract, the projected annual wage increase is 3.0% for both 2025 and 2026. The Company explained:

While this 3.0% assumption is slightly higher than the updated CPI-U projections for 2025 and 2026 sponsored by Attorney General Witness Coppola, the Company's pay practices aren't exclusively driven by overall inflation, which is why wage increases weren't equal to overall inflation when the CPI-U was 8.0% in 2022. Specifically, the Company needs to keep pace with the market in order to ensure it continues to provide a market-competitive overall compensation package to attract and retain qualified employees based on overall market trends in labor rates. Moreover, the Company's projected wage increases are less than the actual market average pay increases in 2025 of 3.6% and market projected increases of 3.5% in 2026, as per a recent survey of salary budget trends published by Payscale. (See Salary Budget Survey (SBS) 2025-2026.) Payscale. These estimated wage increases are corroborated by both the Conference Board and WorldatWork. (See In Corporate America, 2026 Pay Raise Budgets Projected to Hold Steady and WorldatWork: 2026 Salary Increase Budgets Project U.S., Global Caution | WorldatWork.) (emphasis added). (Ex. AG-64, 1).

Moreover — in response to the AG's suggestion that because the CPI rate already includes a labor component, the Company's addition of a labor factor is excessive — the Company explained, in discovery, that:

CPI-U includes a labor component. However, Witness Coppola failed to provide an assessment of how CPI-U is impacted by any labor and wage increases, or what the labor cost increases embedded in CPI-U might be, or how the labor and wage increase contained in CPI-U compare to the Company's labor or wage increases. A 2023 study by the Federal Reserve Bank of San Francisco (<https://www.frbsf.org/wp-content/uploads/el2023-13.pdf> and attachment) found that "[o]verall, labor-cost growth is responsible for only about 0.1 percentage point of recent core PCE inflation" and "Numerous studies have shown that labor costs have little impact on services inflation or inflation overall." (See attachment)

Because the Company has actual information about the impact of the cost of its labor and wage increase, it is appropriate to utilize the Company's projections. (Exhibit AG-64, 2-8).

While the AG points out that the Federal Reserve Study cited by the Company pertains to PCE and not CPI, the Company's point is that labor cost is a very small component of inflation. The AG offers no evidence to substantiate the suggestion that the labor component for PCE is likely lower than the labor component for CPI. (AG Revised Initial Brief, p 17). The generic labor costs assumed in CPI (or PCE) are not reflective of the Company's or the industry's specific wage growth considerations. (Bruzzano, 3T 996). Thus, in spite of the AG's claim that the Company's forecasted wage increase is "unsupported and excessive," (AG Revised Initial Brief, p 16), the Company provided credible support for its projected wage increase, as well as evidence that its projected wage increases are below market. DTE Electric's Reply Brief, pp 11-12.

The PFD notes that "Staff's brief points out that the blended inflation rate proposed by DTE does not incorporate any productivity gains that accompany experience" (PFD, p 98), and claims that a "significant issue that has emerged is the fact that DTE assumes no offset for workforce productivity in its labor inflation projection, based either on internal or external metrics." (PFD, p 101). However, Staff did not make a recommendation for a productivity offset and NRDC-CUB witness Bunch recommended a productivity offset, relying on historical labor productivity offsets (2018-2024), which are unsupported in their applicability to forecast future labor cost offsets or productivity gains. As testified to by Company witness Bruzzano, witness

Bunch provides no evidence of forecasted productivity offsets but uses an annual average of prior years, years which the Company notes include among the most atypical economic conditions in a generation considering the overlap with a global pandemic. (Bruzzano, 3T 998). Company witness Bruzzano also testified that the arguments of witness Bunch do not explain why the category of “Michigan private non-farm workers” is applicable to the Company or the industry and that it is entirely possible that dissimilar industries such as retail are responsible for the change in labor productivity in greater proportion than regulated energy companies. (Bruzzano, 3T 998). Thus, the Company does not agree with the PFD’s characterization of the productivity gain arguments (and other labor-related arguments associated with inflation) of the various parties – which the Company refuted -- and the Company thoughtfully explained its market-based review and determination of labor rates that are grounded in the Company’s actual labor costs. Therefore, the Company respectfully requests that the Commission reject the PFD’s recommendation that the Commission adopt CPI-U inflation rates (PFD p. 102) and instead utilize the Company’s proposed blended inflation rates of 3.40%, 3.00%, and 3.10% for 2024, 2025, and 2026, respectively.

3. Base Capital and Constant Dollar Averaging

The PFD notes that Company witness Chiu explained base capital investments respond to emergent or specific customer needs including planned replacements (Customer Connections, Relocations, Others) and reactive replacements (Storm, Non-Storm, and Substation Reactive) as shown in Exhibit A-12, Schedule B5.4, p. 1, and Exhibit A-23, Schedule M4. Base capital investments are generally calculated based on three- or five-year historical average expenditure amounts, updated by inflation. (PFD, p 102). The PFD also notes that Company witness Hill testified that the Company’s revenue requests for Emergent Replacements and Customer Connections, Relocations, and Other are based on constant dollar averaging (CDA), which

converts historical nominal dollars to real dollars and then averages those real costs as the basis for future projections. This methodology is used for Emergent Replacements; Customer Connections, Relocations and Other; and Restoration O&M. (PFD, pp 102-103).

a. Constant Dollar Averaging

The PFD asserts that the Company's use of CDA has been disputed in the Company's previous rate cases and notes that the arguments for and against the method have generally evolved and the Commission's orders have been somewhat inconsistent. (PFD, p 112). The PFD points out that in Case No. U-21534, the Commission rejected CDA for Emergent Replacements and other capital expenditures, as well as for O&M healthcare expenses, but that the Commission left the door open, instructing that its response to the use of CDA might be different if the evidence showed that these expenditure categories are both volatile and consistently trending upwards. (PFD, p 113; Case No. U-21534 Order dated January 23, 2025, p. 73). The PFD ultimately rejects the use of CDA for Emergent Replacements.

As an initial matter, the Company disagrees with the PFD's characterization of the regulatory history behind CDA as it relates to Emergent Replacements. CDA has been utilized to project the Company's Emergent capital and O&M expense since 2018. This adjustment was presented and approved in Case Nos. U-20162 (the adjustment was undisputed, and presented the Company's Exhibit A-12), U-20561 (May 8, 2020 Order at p.86), U-20836 (November 18, 2022 Order p.63), and U-21297 (December 1, 2023 Order p. 75-76). It was not until the Company's most recent electric rate case, Case No. U-21534, that the Commission disallowed the use of CDA for the projection of Emergent Replacements.

In this case, consistent with the Commission's instruction, the Company offered evidence demonstrating that these expenditure categories are both volatile and consistently trending

upwards. Specifically, Company witness Nelson testified that year-over-year inflation remains “stubbornly above 3 percent” and is expected to stay elevated (Nelson, 4T 3001-3003, 3005, 3023-3024). Company witness Lyons emphasized that the CDA is essential because historical costs fail to reflect today’s economic realities and that CDA ensures forecasts properly account for ongoing upward inflationary trends (Lyons, 4T 3171-3175). Additionally, Company witness Hill presented concrete data demonstrating significant increases in labor and material costs—clear evidence of inflation’s impact—further validating the need for CDA. Contract labor costs have increased significantly since 2019—by approximately 18% for underground work, 31% for overhead work, and 34% for tree trimming. Material costs across major categories have increased between 21% and 468% from 2020 to 2024. (Hill, 4T 2762-2766). Despite objections from Staff and Intervenors, CDA responds to an undeniable economic reality—one that is substantiated on this record—and no opposing party has produced credible evidence to disprove its necessity.

The PFD asserts that the Company has “focus[ed] on a small number of unit costs” and asserts that “[w]hen noting upward trends, the Commission specifically referred to trends in total costs for a given category, not unit costs.” (PFD, p 114). Finding the Company’s “reasoning and focus on a small number of unit costs unpersuasive[,]” the PFD concludes that CDA is not supported and recommends that historical inflation adjustments be removed from all Base Capital programs. (PFD, p 115). While the Company does not consider these costs to be a “small number,” this finding neglects that in addition to material cost increases, the Company also provided evidence that labor resources under its collective bargaining agreements have escalated significantly (Hill, 4T 2764-2765). Specifically, contract labor rates have increased 30% since 2019 (Lyons 4T 3174).

The PFD further concludes that the use of CDA is not warranted based upon an apparent downward movement in costs in both 2020 and 2022. The PFD notes the downward trends were specifically noted by the Commission when it rejected the CDA in Case No. U-21534. However, the Company provided evidence that the trend was due to a reduction in work volume and expenditures and not due to downward pricing trends (Lyons 4T. 3170-3171). The Company also demonstrated, in accordance with the Commission's order, that these expenditure categories are volatile and consistently increasing. Inflation adjustments should be applied to account for demonstrated material and labor costs increases. Yet, the PFD's conclusion effectively relies on an unrelated factor (i.e., work volume reduction in certain years) to reject the application of CDA methodology. Accordingly, the Company respectfully disagrees with the PFD and requests that the Commission disregard the recommendation in the PFD and allow the Company's proposed use of CDA to provide for a more accurate forecast of future costs and to ensure that the Company's ability to purchase the same units of materials and labor over time is maintained.

b. Emergent Replacements

The Emergent Replacements category of Base Capital Programs includes Storm, Non-Storm, and Substation Reactive programs. Expenditures in these programs are necessary for public safety and delivering reliable power to the Company's customers. Investments in these areas are shown on Exhibit A-12, Schedule B5.4, page 3. (Hill, 4T 2760). The expenditures for Storm, Non-Storm, and Substation Reactive activities consist of labor and material costs, and the Company forecasted Emergent Replacement expenditures using a five-year average, which smooths out year-to-year variation, including weather. (Hill, 4T 2760). Storm expenditures for 2025 and 2026 are projected at \$276.4 million and \$284.9 million (Exhibit A-12 Schedule B5.4, page 2, line 3, columns (f) and (g)), respectively, based on a 5-year inflation adjusted historic average of the

period 2019-2023. (Hill, 4T 2775). Non-storm emergent expenditures for 2025 and 2026 are forecasted at \$233.4 million and \$254.2 million, respectively (Exhibit A-12 Schedule B5.4, page 2, line 4, columns f and g), based on a five-year inflation adjusted historic average of the period 2019-2023. (Hill, 4T 2778). Substation Reactive expenditures for 2025 and 2026 are forecasted at \$56.6 million and \$59.9 million, respectively (Exhibit A-12 Schedule B5.4, page 2, line 5, columns (f) and (g)), based on a five-year inflation adjusted historic average of the period 2019-2023. (Hill, 4T 2780-2781).

The AG recommended significant disallowances based on general disagreement with the Company's method of accounting for inflation (AG's Revised Initial Brief, p 19) as well as on specific adjustments. AG witness Coppola performed his own calculations to forecast total capital expenditures for Emergent Replacements of \$486,712,000 for 2025 and \$497,995,000 for 2026, which he compared to the Company's forecasted expenditures of \$543,980,000 for 2025 and \$575,852,000 for 2026. AG witness Coppola recommended the removal of \$57,268,000 for 2025 and \$77,857,000 for 2026 from the Company's forecasted capital expenditures. (Coppola, 4T 3436). In briefing, the AG also advocates for the removal of \$13,654,000 of corrective maintenance in the capital forecast adjustments proposed for Emergent Replacements, as well as \$8.0 million for 2025 substation facility repair and \$9,847,000 for 2026 corrective maintenance, arguing that these costs were not substantiated by the Company. (AG's Revised Initial Brief, pp 27-28).

The PFD does not take issue with the Company's requests. However, the PFD agrees with the AG that the Company "did not fully support" the corrective maintenance and substation facility repair costs that were included as separate line items in cost categories that are significant. (PFD, p 120). The PFD opines that while the Company stated what these expenditures were for, it did not

explain why they should not simply be included as part of the five-year average of Non-storm or Substation Reactive spend. (PFD, p 120). The PFD recommends adoption of the AG's disallowance of \$13.7 million for 2026 for Non-Storm corrective maintenance, and \$8 million and \$9.85 million for facility repair and corrective maintenance under the Substation Reactive Base Capital program. (PFD, p 120).

While the Company supports the PFD's acceptance of its proposed Emergent Replacement investments, the Company does not agree with the PFD's recommendation for disallowances of \$13.7 million for 2026 for Non-Storm corrective maintenance, and \$8 million and \$9.85 million for facility repair and corrective maintenance under the Substation Reactive Base Capital program. (PFD, p 120).

With respect to the recommended disallowance of \$13.7 million for 2026 for Non-Storm corrective maintenance, the Company reiterates that AG witness Coppola did not justify or explain this adjustment in his testimony. The AG should not be heard to argue, for the first time, in the AG's Initial Brief, that the proposed expenditure is inappropriate. This argument is the very type of last-minute, unsupported criticism barred by the standard established by the Commission in its January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, pp 37-38. DTE Electric's Reply Brief, pp 63-64. Therefore, the Commission should note the AG's evidentiary omission and reject the PFD's recommended \$13,654,000 disallowance as also unsupported.

Furthermore (and contrary to the PFD's incorrect conclusion at PFD p. 120), the Company fully supported the Non-Storm and Substation Reactive Corrective Maintenance as separate line items. The Company described that it is performing Corrective Maintenance, although incoming demands surpasses the available investment resulting in a backlog (Robinson, 4T 2054-2056). This point was noted as sufficient evidence in the PFD's approval of the incremental Corrective

Maintenance O&M (PFD, p. 415). As of December 15, 2024, the Company determined that completing the CM backlog will require \$23.5 million in reactive capital and \$7.3 million in O&M expenses (Robinson, 4T 1957). Note both the O&M expense and capital investment are required for the program to perform the necessary work. Additionally, because the proposed level of Corrective Maintenance has not been performed within the five-year historical period, it is not reflected in the historical average and must therefore be shown separately.

In this proceeding, the Company requests authorization for \$23.5 million in reactive capital (\$13.7 million included in Non-storm and \$9.85 million included in Substation Reactive), to implement its plan to complete the repairs or replacements for damaged or defective equipment.

With respect to the amounts projected to be spent on substations in need of facility repairs, Company witness Hill's testimony justifies the need for this investment and explains that the work is to replace critical electrical grid equipment that has failed. (Hill, 4T 2782). Specifically, Witness Hill testifies:

Q42. Can you describe the Projected 2025 Substation Facility Repair capital expenditure shown on Exhibit A-12, Schedule B5.4, page 3, line 25, column (h)?

A42. Yes. The Company projects to spend \$8 million in 2025 on three substations in need of facility repairs. The Troy substation experienced a structural failure of a side wall during a 2024 wind weather event. The Chestnut substation side wall is also in need of replacement. Work scope includes engineering, permitting, and construction in 2025¹⁷. In addition, the Imlay substation site needs replacement of steel structures and foundations due to steel erosion and loss of structural integrity to several connecting plates and support brackets. These facility repairs will address the structural concerns at each of these substations.

(Hill, 4T 2782). The AG's Initial Brief, for the first time, argues that this \$8 million projection be eliminated, speculating that it might be redundant to recurring spending projected to occur under

¹⁷ The inclusion of engineering and permitting in the scope of activity for these projects is indicative that these investments are planned and not reactive, since reactive work does not typically include those activities.

the substation reactive work category (AG's Revised Initial Brief, pp 28-29). This claim rests on unsupported speculation, not record evidence.¹⁸ As previously stated, the AG should not be heard to hypothesize and argue, for the first time in her Initial Brief, that a proposed expenditure is inappropriate. The PFD's acceptance of unsupported speculation is improper and should be rejected.

Therefore, the Commission should note the AG's evidentiary omissions and reject the PFD's recommended disallowances.

c. Other Base Capital Adjustments

i. Projected Meters

Expenditures in the Electric System Equipment subcategory are necessary to maintain an inventory of critical spare equipment—such as transformers, regulators, and meters—to support emergent replacements and planned projects and allow them to proceed expeditiously. (Hill, 4T 2792-2793). The Company forecasts Projected Meter expenditures of \$16,735,000 for 2025 and \$17,254,000 for 2026 including a CDA adjustment. Exhibit A-12, Schedule B5.4. Staff recommended that \$6,301,229 for the 12 months ending December 31, 2025, and \$6,542,690 for the test year, be disallowed for Projected Meters, noting that the Company purchased 115,661 meters in 2024, while the average number of meters purchased in the prior three years was 46,000. Staff reasoned that this leaves DTE Electric with a 70,000 meter surplus to be delivered sometime in 2025 or 2026, but that 2025 and 2026 proposed meter purchasing was based only on the 2021 to 2023 average investments plus inflation, leaving the “surplus” meter inventory untouched. (Hansen,

¹⁸ *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency's decision was not supported by evidence that a reasonable person would consider adequate).

5T 5169).AG witness Coppola recommended an increase in the Company’s proposed spending. (Coppola, 5T 3447). The PFD adopts Staff’s proposed adjustments for 2025 and 2026, which, after removal of CDA, result in a disallowance of \$5.345 million in 2025 and \$5.474 million in 2026. (PFD, p 132). The PFD suggests that without knowing more about the actual stock of meters that the Company has on hand, there is no way of being able to discern whether the meter purchases are reasonable and prudent, and nothing precludes DTE Electric from properly supporting an increased meter purchase in a future rate case. *Id.* The Company does not agree with the PFD’s recommendation. Through the rebuttal testimony of witness Hill, the Company explained that the meter purchase made in 2024 was simply a one-time additional purchase to maintain an inventory. (Hill, 4T 2828). Specifically, Company witness Hill testified that as a result of higher-than-normal meter failures in 2023 and an increase in supply chain lead times from 4-5 months to 12-15 months, the Company ordered additional meters in 2024 to ensure sufficient inventory. (Hill, 4T 2828). Company witness Hill pointed out that Staff’s Exhibit S-22.1 Projected Meters Adjustment Calculation shows that in the years 2021 through 2023 the Company installed 36,085 more meters than it purchased. (Hill, 4T 2828). The table below, taken from Company witness Hill’s rebuttal testimony, depicts installations and purchases from 2021-2023.

**Table 4 2021-2023 Meters Installed Compared to Meters Purchased
(Excerpt S-22.1)**

Year	Line No.	Meters Installed	Line No.	Meters Purchased	Delta
2021	1	59,214	6	38,240	(20,975)
2022	2	54,296	7	59,320	2,024
2023	3	59,920	8	42,785	(17,135)
	Total	173,430		137,345	(36,085)

(Hill, 4T 2828). While the PFD focuses on the “actual stock” of meters the Company carries, the Company does maintain an inventory and achieves that inventory by balancing installations against purchases. Furthermore, the PFD’s conclusion that “DTE’s declarations of necessity are not enough” is itself incorrect (since the Company provided a cogent rationale) and disregards the compelling meter installation/purchase trends in the record. (PFD p. 132) Given that more meters were installed from 2021-2023, the Company had to make a catch-up purchase in 2024 to both replenish its inventory and fill anticipated needs. Thus, the Company does not have a “surplus” inventory that Staff envisions to meet customers’ 2025 and 2026 needs. For this reason, and to ensure sufficient inventory to meet customer needs, the Commission should reject the recommendation of the PFD and accept the Company’s request.

E. Distribution Strategic Capital Programs

1. Overview

Strategic capital is a critical component of DTE Electric's overall approach to investment in its distribution system. Contrasted with base capital, which is deployed in response to emergent situations or customer needs, strategic capital deployment is driven principally by reliability needs. (DTE Electric's Initial Brief, p 42). For the specific strategic capital programs, the Company requests a total of \$1.06 billion, broken down as follows: \$448.6 million for Infrastructure Resilience and Hardening; \$382.99 million for Infrastructure Redesign and Modernization; and \$229.1 million for Technology and Automation. Exhibit A-12, Schedule B5.4 p 1. As described below, the Company uses a suite of analytical tools to prioritize strategic capital deployment. The PFD notes the way that Company witness Chiu described DTE Electric's grid, observing that "Michigan – and the City of Detroit, in particular – has one of the oldest electric grids in the country, and that system is showing its age." (PFD, p 134 citing Chiu, 3T 1096). The PFD also recognizes the fact that 45% of the Company's distribution infrastructure is 4.8 kV installed between 1930 and 1965, which the Company explains brings both operational and safety challenges. (PFD, p 134). Undisputed in this proceeding, and underscored by the Liberty Audit, is that Company operates one of the oldest electric grids in the country. Much of the grid is composed of aged lines and equipment that create capacity constraints, pose safety and operational challenges, and impede efficient restoration during outages. The Company is taking concrete action to maintain safe and reliable operation. The investment plans put forth in this proceeding provide a roadmap and framework for accomplishing the Company's commitment to customers, including the objectives of reducing power outages by 30% and cutting outage time in half by 2029. (DTE Electric's Initial Brief, p 41). While Intervenors challenged certain of the Company's

investment plans, the record shows that these plans are reasonable, thoughtful, consistent with good utility practice, and ultimately valuable for customers.

2. Modeling

The PFD concludes that DTE Electric's Global Prioritization Model (GPM) and Reliability Model (RM) should be considered as "pieces of evidence that may provide some support" for the Company's proposals. (PFD, p 146). It does not attempt to resolve the methodological debates raised in the case and stops short of "fully examin[ing] and address[ing] the strengths and weaknesses of the GPM and RM" due to the "strict time constraints for completing a rate case." (PFD, p 146). Insofar as the PFD concludes that the GPM and RM provide support for the Company's proposals, the Company agrees and emphasizes the extensive record demonstrating the Company's optimization and refinement of those models to address intervenor and Commission feedback raised in prior cases. The record shows that the GPM and RM are robust, data-driven tools that the Commission has already found do not require further prescriptive changes and which have been validated against actual performance. (Case No. U-21534 Order dated January 23, 2025, pp 97-98; Kryscynski, 3T 1270, 1288-1289). By contrast, the PFD recommends that the Company's benefit-cost analysis (BCA) should be afforded minimal weight, principally due to the BCA's proprietary nature and alleged understatement of costs and overstatement of benefits. (PFD, p 153). As noted and explained extensively in its pre-filed testimony and briefing in this docket, the Company disagrees with these criticisms. The record shows that the Company's BCA is rigorous, methodologically transparent, conservative in key assumptions, 1898 & Co.'s models (used here) have been approved by the Public Utility Commission of Texas for three different utilities, and is resilient to the critiques raised by the PFD. Moreover, even when modified to account for various intervenor criticisms, sensitivity analyses

show that the BCA's principal conclusions remain materially unchanged and continue to support approval of the Company's proposed investments. (See generally, De Stigter 4T 1835-1911; Exhibit A-28, Schedules R2, R3 Revised, R4 and R5 elaborating on the rigor and details supporting the Company's Pole and Pole Top Maintenance & Modernization (PTMM), Strategic Undergrounding Pilot (SUG), Distribution Automation (DA), and Grid Automation Telecommunications programs, while refuting claims that the Company's BCA exaggerates the amount of investment that is likely to be cost effective and that the BCA does not support investment decision making.)

The Commission should consider the Company's presented modeling in its appropriate context. The PFD properly recognizes that the Commission has already articulated how modeling should be considered in contested cases. (PFD, p 146). In Case No. U-21534, the Commission explained that it will weigh the Company's planning tools—principally the DGP, GPM, and RM—as evidence supporting specific cost recovery requests, without attempting to adjudicate every methodological critique within the confines of a general rate case (January 23, 2025 Order in Case No. U-21534, p 97). In that same order, the Commission concluded that there was no need for the Company to implement extensive changes to its modeling processes and that requiring a full BCA for every investment is neither practical nor advisable (January 23, 2025 Order in Case No. U-21534, pp 97-98). The record in this case is even stronger. The GPM has been refined since the prior case, the RM has been updated to reflect a full calendar year and to incorporate reliability performance from 2023 and 2024¹⁹, and the Company supplemented these tools with comprehensive BCAs to further enhance the record with respect to key investments.

¹⁹ Company witness Kryscynski explained the various improvements to the GPM and RM. (3T 1200-1202, 1218-1219)

Against that framework, the PFD errs to the extent it discounts the probative value of the Company's modeling record. The Company appreciates the PFD's acknowledgement that the GPM and RM provide evidentiary support, but the Commission should not minimize that evidence in light of its guidance and the new validation provided in this record. With respect to the BCA, the PFD's recommendation to afford "minimal weight" rests on conclusory assertions. Those assertions, however, are rebutted by the Company's detailed testimony, workpapers, discovery responses, stakeholder technical sessions, and sensitivity testing, as well as by quantitative demonstrations that the intervenors' proposed adjustments would not change outcomes in a way that undermines the investment case. (Chiu, 3T 1150; De Stigter, 4T 1872-1897, 1903-1910).

a. Global Prioritization and Reliability Models

i. Global Prioritization Model

DTE Electric agrees with the PFD that the Commission need not adjudicate every modeling criticism in a rate case, but objects to the intervenor criticisms echoed by the PFD that the GPM's scoring is subjective and not cost-based. The Company submits that the record in this proceeding warrants affording substantial weight to the GPM and its conclusions. The GPM is a sound prioritization framework that balances objective metrics with expert judgment, has been improved in this case for transparency and accuracy, and aligns with the good-practice findings of the Liberty Audit. (Kryscynski, 3T 1197-1204, 1270-1276).

Despite criticism from intervenors repeated in the PFD, the record shows that a majority of the GPM's scoring weight derives from objective inputs. Five dimensions are entirely calculated from objective measurements and together contribute 56% of total scoring. If the EJ multiplier, which is grounded in the MiEJ Screen, is treated as objective, then roughly 79% of total scoring is objective. The remaining dimensions that incorporate subject-matter expertise still rest on

measured load and equipment ratings. (Kryscynski, 3T 1274-1276; Ex. A-23, Schedules M14, M14.1).

Intervenors' concerns that the GPM conflates discrete projects with large programs or that it is "meaningless" for capital planning do not withstand scrutiny in this record. The Company explained that the GPM's relative ranking method evaluates benefits per dollar and thus places large and small initiatives on equal footing. (Kryscynski, 3T 1212). The Company also answered discovery explaining how projected improvement inputs are anchored to measured pre- and post-project data where applicable, and it provided those datasets. (DTE Electric's Reply Brief, pp 8-12; Ex. A-46, Sch. LL4). On this record, the Commission should reaffirm its conclusion in Case No. U-21534 that no additional prescriptive changes to the Company's modeling are necessary and should credit the GPM as reasonable, data-driven analytical support for investment prioritization. (January 23, 2025 Order in Case No. U-21534, p 98; Kryscynski, 3T 1270).

ii. Reliability Model

As with the GPM, the PFD recites various intervenor criticisms of the RM related to baseline construction, expert judgment, and ex-MED scaling. The record demonstrates that the RM is a rigorous analytical tool which has been updated in this case to include a full calendar year and actual 2023-2024 performance, has accurately forecasted system outcomes, and ties investment effectiveness to pre- and post-project data at the circuit level. (Kryscynski, 3T 1213-1219, 1288-1289; Ex. A-23, Sch. M12; Ex. A-46, Sch. LL4). The RM, therefore, should be afforded substantial weight in evaluating reliability-driven improvements.

The Company described the RM's structure in detail: it estimates reliability improvements from proposed investments on a circuit-by-circuit basis, establishes baseline reliability, applies program-specific effectiveness drawn from measured outcomes and expert analysis where

appropriate, accounts for degradation over time, and translates ex-MED to all-weather performance within empirically observed bands. (Kryscynski, 3T 1213-1217, 1285-1287; Ex. A-23, Sch. M12). The Company provided multiple examples where effectiveness rests squarely on measured historical outcomes and supplied related data in discovery (Kryscynski, 3T 1280-1281; Ex. A-46, Sch. LL4). The Company also explained and defended use of ex-MED baselines to reduce weather volatility and improve signal-to-noise for system improvement trends, noting that the majority of events and customer impacts occur on ex-MED days. (Kryscynski, 3T 1283-1284).

Most importantly, the RM has been validated against outcomes. The RM projected all-weather SAIDI of 504 minutes and SAIFI of 1.30 for 2024 while actual performance was 483 minutes and 1.25, meaning the model's projections were conservative by approximately 4%. Through August 2025, the Company's forecasts were within the RM's favorable weather band, and the ex-MED forecast was 1% better than the model projection. For the last two years, the RM has forecast results that are more conservative than actual performance, demonstrating credibility and usefulness for investment planning. (Kryscynski, 3T 1288-1289). On this record, the RM should be valued as reliable, decision-useful evidence supporting the reasonableness and prudence of DTE Electric's reliability investments.

Despite the recited reservations, the PFD ultimately does not engage with the criticisms, acknowledging that the RM provides support for the Company's proposed investments. Consistent with its prior conclusions on this modeling, the Commission should acknowledge the value it provides and recognize the Company's commitment to continued improvement of its analytical tools evidenced in this case both with respect to the GPM and the RM.

b. Benefit Cost Analyses

The PFD recommends according “minimal weight” to the Company’s BCA, citing concerns that the 1898 & Co. (1898) model is proprietary, that the costs omit revenue requirement components like the ROE, taxes, and debt, and that the benefits are overstated due to use of the ICE tool, a “critical customer” multiplier, and exclusion of 2024 reliability data. (PFD, p 153). The record does not support this conclusion.

The Company’s evidence demonstrates that its BCA approach is transparent in method, data-driven, and conservative; that it yields results materially similar when additional revenue requirement costs are incorporated; and that critical-customer treatment is both justified and not outcome-determinative. The Company walks through a few of the more predominant criticisms of the Company’s BCA below, but in short, the BCA should be afforded meaningful weight as part of the modeling suite that the Commission uses to evaluate proposed investments, and which the PFD concedes provide support for those investments.

Intervenors argue, among other things, that the Company’s BCA understates costs by not embedding a full revenue-requirement framework in the cost calculation. The Company demonstrated that, even assuming a conservative 10% upward shift in costs to approximate revenue requirement effects where relevant, the PTMM Groundline average BCR falls modestly from 1.71 to 1.64 and the PTMM Pole-Top average BCR falls from 2.81 to 2.63, and only a de minimis fraction of circuits move below 1.0. For distribution automation (DA), a comparable analysis shows an approximate 10% decrease in the average BCR, with program-level conclusions unchanged. (De Stigter, 4T 1884; 1872-1881, 1891-1897). It should be noted that Company witness Lepczyk showed that the expected difference with a revenue-requirements framework is

significantly less, 2% would be a more appropriate value. (4T Lepczyk, 2934). With this value, the impact to the BCA would be minimal.

The PFD also restates intervenors' generalized skepticism regarding the DOE's Interruption Cost Estimator (ICE) tool, which they claim overstates the reliability value of improvements in the model and places a higher value on service interruptions avoided by "critical customers." (PFD, pp 147-148). The Company explained how ICE is applied and why its use is appropriate. Specifically, the record reflects that the "critical customer designations" mirror operational restoration priorities for facilities like hospitals, fire departments, and schools. (De Stigter, 4T 1892-1896). The Company disagrees with any suggestion that these types of entities should not be prioritized in electric service reliability and restoration. The evidence shows that removing the 3X multiplier changes very few circuit-level results, with those few remaining near the breakeven threshold and with other unmodeled benefit streams likely to close the small gap. (DeStigter, 4T 1892-1896). In short, the multiplier is supported by the heightened impact of outages and is not outcome-determinative for program justification.

The PFD also echoes claims that 2019-2023 Outage Management System (OMS) data overstates future outages because 2024 all-weather SAIDI improved. (PFD, p 149). However, when the BCA analysis was performed, 2024 data was not yet available. (De Stigter, 4T 1899). It is not reasonable to assume, as ABATE Witness Fitzhenry implicitly does, that the next 20 years of outages will be most similar to 2024. (De Stigter, 4T 1899-1902). Using a multi-year historical baseline reduces single-year weather noise and is appropriate for a long-term planning horizon.

Finally, the PFD's premise that a "proprietary model" inherently disadvantages parties, (PFD, p 153), does not comport with the record in this case. The Company sponsored and entered into the record a detailed 135-page Program Benefit Cost Analysis Report, supporting exhibits,

and extensive discovery responses that were available to all intervenors,. providing transparency and supplying a robust evidentiary basis for the Company's proposed investments. (De Stigter, 4T 1839-1852). 1898 conducted multiple technical sessions with stakeholders, answered methodology questions, and provided workpapers and sensitivity analyses that allow independent review of assumptions and impacts. (Chiu, 3T 1151-1152, citing CEO witness Volkmann). The method is transparent even if some software components are proprietary, and the Company has taken significant and meaningful steps to provide visibility into the BCA modeling assumptions, methodology and results. On this record, the Commission has ample basis to afford the Company's BCA meaningful weight.

In summary, the GPM, RM, and BCA are complementary tools that make the record stronger together than any one tool in isolation. The GPM ensures that the portfolio addresses safety, reliability, capacity, and customer value across the system using predominantly objective inputs. The RM links programs to measured reliability improvements at the circuit level and has forecast system outcomes conservatively and accurately in 2024 and 2025, validating its use for planning and for testing program reasonableness. The BCA translates reliability and resilience benefits into monetized customer value and demonstrates that the majority of the evaluated investment level yields benefits in excess of costs under a range of conservative assumptions. This multi-tool collaboration is exactly the kind of evidence the Commission contemplated in Case No. U-21534, and it supports approval of the Company's distribution investments as reasonable and prudent. According only "minimal weight" to the BCA would deprive the Commission of probative, triangulated evidence on where investments will deliver the greatest customer value per dollar. The Commission should give considerable weight to DTE Electric's suite of planning tools as meaningful support for the Company's proposed investments.

3. Pole Top Maintenance and Modernization

The Company's PTMM program is designed to inspect and maintain overhead distribution equipment and replace PTMM equipment with new materials that offer greater strength and durability, which indisputably enhance system reliability. (Robinson, 4T 1933). The PTMM program is funded for 2025 at \$121 million. (PFD, p 155). In this proceeding, the Company is requesting an increase to \$200 million in the 2026 test year, (Robinson, 4T 1942-1944), and Staff supports the Company's request. (PFD, p 155).

a. Pole Replacement Costs

The PFD recommends a \$2.622 million disallowance for material costs associated with pole inspection and replacement on the basis that if DTE Electric had implemented four-to-five-year pole inspection cycles in past years (2019-2023), as suggested in the Liberty Audit, it would have completed more inspections and replacements while material costs were lower, thereby realizing savings on materials that it now has to purchase at higher prices. (PFD, pp 160-162). As a result, the adjustment represents "the large discrepancy between the Company's pole inspection cycle in 2019 compared to the industry standard of four to five years benchmarked by DTE in the instant proceeding and recommended in the Liberty Audit." (PFD, pp 162-163). The Company disagrees with this recommendation and its underlying rationale.

As noted by Company witness Robinson, the purported savings in pole material costs is speculative because it assumes that the Company would have identified and replaced all poles in past years that it intends to repair in the test year. (Robinson, 4T 2045). More importantly, the PFD's recommended adjustment is simply a penalty (despite suggestions otherwise) and raises retroactive ratemaking concerns, as it seeks to claw back material costs from 2019 based on past inspection practices that were inconsistent with the industry benchmarks noted in the Liberty Audit

report, which was issued in September 2024. (PFD, p 162-163).²⁰ The salient facts were neither known to the Company nor could have been known to the Company. As Company witness Robinson aptly explained in response to Ann Arbor’s suggestion, that proposal “does not appear to consider the cost of money” and it “does not seek to accurately estimate the correct cost and rates associated with replacing poles and other equipment identified as needing replacement in 2025 and 2026 – it is only intended to penalize the Company for what AA believes should have occurred in the past.” (Robinson, 4T 2045) The Company is seeking an increase in its PTMM program funding in this proceeding because its current funding levels do not allow it to successfully complete four-to-five-year inspection cycles. (Robinson, 4T 1943). The Commission should reject the PFD’s proposed pole replacement cost disallowance.

b. Capitalization of PTMM Costs

During the proceeding, several intervenors contended that DTE Electric’s capitalization of certain activities associated with PTMM was inconsistent with the Uniform System of Accounts (USoA). (PFD, p 165-166 (citing MNSC Initial Brief, pp 157-168)). The Company’s Initial Brief summarized the Company’s testimony on its PTMM expense and capitalization practices and explained how they comply with the USoA. (DTE Electric’s Initial Brief, pp 55-56 (citing Stephens, 5T 4524 – 4525, Uzenski, 4T 2507)). The Company also noted that none of the intervenor witnesses who objected to DTE Electric’s capitalization policies are accountants or

²⁰ This penalty proposal is unlawful. “[T]he essential principal of the rule against retroactive ratemaking is that when the estimates prove inaccurate and costs are higher or lower than predicted, the previously set rates cannot be changed to correct for the error; the only step that the MPSC can take is to prospectively revise rates in an effort to set more appropriate ones.” *The Detroit Edison Co v Public Service Comm*, 416 Mich 510, 523; 331 NW2d 159 (1982) (opinion by Fitzgerald, C.J.). There is no reasonable argument that MERC will experience \$0 in Operations and Maintenance expense during any period addressed in this proceeding.

qualified to render an opinion on DTE Electric’s accounting practices. (DTE Electric’s Initial Brief, p 56).

Despite DTE Electric’s explanations, the PFD found that the Company’s capitalization policies and RU classifications “are an ongoing issue of concern” and that the Commission should direct either a standalone proceeding involving all of the major utilities or specifically direct DTE Electric to address the issue in its next depreciation case. (PFD, p 166). The record does not support the PFD’s recommendation. The Company adheres to the USoA requirements and sufficiently supported its PTMM capitalization policies and classifications in this proceeding. (See generally, Company witness Uzenski, 4T 2506-2510 explaining, inter alia, the proper interpretation of the Uniform System of Accounts (UsoA), including that “[t]he cost of inspections related to the PTMM program has been expensed as incurred starting in 2023” and that “only those tests that lead to a pole replacement (a capital job) are capitalized”) The Company takes exception to this recommendation and submits that neither a standalone proceeding nor further discussion in the Company’s next depreciation case is necessary or appropriate.

4. Redesign and Modernization²¹

DTE Electric respectfully requests that the Commission reject the PFD’s recommended reductions to the Company’s Redesign and Modernization²², 4.8kV Conversion Program, and 8.3kV Pontiac Conversion Program investments. The record reflects broad agreement among Staff and intervenors that these projects are reasonable, necessary, and aligned with the Company’s planning criteria and reliability objectives. The PFD’s concerns largely involve timing and documentation—not the underlying need for or prudence of the investments. Where Staff proposed

²¹ The PFD titled this section Subtransmission Redesign and Rebuild

²² *Id*

adjustments, it generally did so while expressly supporting the Projects' merits, and often proposed only interim, partial cuts pending additional updates.

In light of the consensus that the projects are reasonable and prudent, the Commission should not risk prudent execution by arbitrarily reducing reasonable investment levels based on hypothetical considerations or arbitrary adjustments. The adjustments endorsed by the PFD prioritize form over substance and schedule optics over merit, even as Staff and the PFD repeatedly acknowledge that the projects meet the primary test, which is that they are reasonable and necessary. The Commission should reject methodologies that linearize inherently non-linear construction phasing, flatten variable location-driven costs, or require novel, hyper-granular documentation, and instead give weight to the record consensus that these investments are needed and prudent.

a. Transformer High Side Protection Program (Sched. B5.4, p. 11, line 5)

This investment relates to a reliability program designed to mitigate observed NERC reportable system issues that could result in loss of service to 100+ MVA of customer load. (PFD, p 169). The PFD acknowledges that both Staff and ITC support the need for the program and acknowledge the reliability benefits it would provide. Prudence and necessity are not at issue—the only concern raised is that 2025 year-to-date spend appears low as compared to projections. (PFD, p 169). On this basis, Staff suggests disallowances of approximately \$4.6 million for 2025 and \$3.0 million for the test year—a significant cut of over half of the proposed investment. The Commission should not limit the Company's ability to execute on a project that is acknowledged to be needed and prudent over pacing optics.

As the Company has explained, year-to-date annualization is a poor proxy for outcomes in a program that, by design, executes in lumpy phases around planned outages, material deliveries,

and outage coordination with the transmission owner. Early-year engineering and procurement naturally give way to larger installation outlays later in the year; flattening this cadence into a five-month run-rate misstates execution and risks underfunding risk-mitigation work the PFD and Staff agree is warranted. (Stowe, 2T 191-192; Ex. A-23, Sch. M6)

Second, the suggestion that additional “implementation detail” is a prerequisite for recovery disregards both the record and Commission practice. DTE Electric filed a multi-year plan for this portfolio that sequences installations through 2034, including scope, milestones, and prioritization in Exhibit A-23, Schedule M6. The Commission has not required project-by-project, resource-loaded work packages or pre-execution artifacts to establish prudence in rate cases of this kind, and Staff’s own support confirms that the level of detail provided is sufficient to establish reasonableness. Imposing unprecedented, hyper-granular documentation here would delay important work without meaningfully improving the Commission’s ability to adjudicate prudence (Stowe, 2T 189-190; Ex. A-23, Sch. M6).

Third, the consequences of delay are not abstract. The program mitigates NERC-aligned risks by installing circuit switchers/breakers on the high side of substation transformers to reduce the probability and consequence of transformer and network events. Trimming funding on the basis of a partial-year snapshot would defer installations and prolong exposure to exactly the risks this program addresses. The Commission should put significant weight in the cross-party consensus on necessity and approve DTE Electric’s request so that execution can proceed on the schedule laid out in the record. (Stowe, 2T 189-190; Ex. A-23, Sch. M6).

b. Trunk 3509 and CODI Alfred Substation Expansion (Sched. B5.4, p. 11, lines 28 and 31)

Trunk 3509 and the CODI Alfred Substation Expansion (Alfred) are capacity and operability projects that Staff expressly supports and the PFD itself deems “reasonable and

necessary,” yet the PFD adopts reductions by annualizing the first five months of 2025 spend and labeling DTE Electric’s execution plans as “overly optimistic.” (PFD, p 173). Both projects resolve observed capacity issues.

The PFD’s rationale rests on two premises. First, it extrapolates partial-year spend to the full year to conclude that DTE Electric’s schedules are optimistic and that customers might fund investments “not actually being made” within the year, despite acknowledging the merits of the projects and that delays stem from circumstances outside the Company’s control. Second, it suggests more frequent, granular progress updates as a precondition to full approval. (PFD, pp 171-174). Neither premise contests need or prudence; both speak to execution cadence which is largely—as the PFD acknowledges—based on circumstances beyond the Company’s control.

Forecasts should reflect how redesign and modernization projects actually execute, and the Commission should be mindful of these realities as it reviews the cadence of construction spending. Construction cashflows are intentionally non-linear—engineering, permitting, procurement, outage coordination, and long-lead deliveries front-load planning dollars and push installation spend into narrow outage windows later in the year—so linearizing a five-month snapshot understates delivery and mischaracterizes progress. The Commission has also stated that in-service within the test year is not dispositive for rate recovery, which cuts against the PFD’s proposed adjustment to linearize partial-year spend. (Stowe, 2T 244, quoting Case No. U-21297)

For Trunk 3509, the record identifies planning criteria violations and operability constraints addressed by the redesign and rebuild scope; Staff supports the initiative and the PFD finds it reasonable and necessary. Annualizing early-year spend ignores hazard mitigation, procurement, and outage-window sequencing that concentrate physical installation later in the year, precisely the “lumpy” execution the Company described. For Alfred, the substation’s load and area growth

require expansion. The PFD does not dispute any of the drivers for this expansion, and the PFD notes that it does not doubt the Company’s ability to complete the projects. (PFD, p 173). On this record, reductions premised on partial-year annualization and update cadence should yield to Staff’s and the PFD’s own findings on reasonableness and necessity, and the Commission should approve the requested test-year and bridge-period expenditures. (Stowe, 2T 191-192).

c. CODI Targeted Network Secondary Cable (Sched. B5.4, p. 11, line 33)

The City of Detroit Infrastructure (CODI) Targeted Network Secondary Cable project is needed to replace certain cables with high probability of failure. Although there is not dispute as to the reasonableness and prudence of the project in the PFD, it adopts Staff’s unit-cost normalization by excluding 2024 “Other” costs to derive per-foot values for 2025 and 2026, concluding that DTE Electric did not provide sufficient detail to quantify location-driven variability in the bridge and test years. (PFD, pp 174-177).

As with other redesign and modernization programs, the PFD adopts recommendations to lower costs despite misalignment with how costs are allocated and phased. Staff acknowledges that underground unit replacements vary materially by site, and yet Staff recommends a normalized unit cost approach that does not distinguish across different neighborhoods and years. The PFD suggests that the Company should have provided more detail to support this variability but nonetheless concludes that “it is likely the case that the cost of cable installation is quite variable, depending on the actual conditions.” (PFD, pp 176-177). The PFD’s approach further understates actual costs by omitting legitimate 2024 execution expenses from the “Other” category that were required to perform the work. Even if the Commission insists on computing a 2024 unit cost, these costs must be included in that calculation. When included, the implied per-foot values differ substantially from Staff’s figures. (Stowe, 2T 193-195).

The PFD hinges its recommendation on the notion that costs categorized as “Other” are not included in bridge and test-year projections. (PFD, p 176). The Company categorizes distribution investments into material, labor, and other, using actual pre-allocated data for 2024 and SME-based or historical methodologies for forecasting 2025–2026, with “other” reflecting bundled actuals or specific forecasted items like property purchases and customer load protection in this proceeding. (Exhibit A-50 Schedule QQ2) The different methodologies result in variations in the categorization of material, labor and other. The “Other” category in 2024 properly includes valid overhead and material expenditure required to perform the work. (Stowe, 2T 193) Accordingly, pulling 2024 “Other” costs out of the base year to normalize a per-foot cap for 2025 and 2026 is an apples-to-oranges exercise that both strips real 2024 execution costs and then imposes a single proxy on inherently variable, site-specific work plans that the record details extensively. Given the nature of the “Other”-categorized costs and the inherent variability of construction costs, the Commission should conclude—as Staff and the PFD do—that the project is reasonable and prudent and should, therefore, be fully funded.

Notably, Staff calculated its cost adjustment using 11,500 feet instead of the updated 12,000-foot plan for 2026, which, when combined with Staff’s normalized unit cost, further drives down funding based on a misunderstanding by Staff as to the nature of the project. The PFD recommends Staff’s adjustment. (PFD pp. 176-177) If the Commission is to use a normalized unit cost, it should at least apply that cost to the correct footages 12,000 feet for 2026 and 12,500 feet for 2025. (See PFD, p 175 acknowledging Staff’s adoption of the lower 11,500 footage). The Commission should reject Staff’s \$1.233 million and \$102,303 adjustments for 2025 and 2026, respectively.

d. 4.8kV Grosse Pointe Substation and Circuit Conversion North (Sched. B5.4, p. 12, line 54)

The Grosse Pointe Substation and Circuit Conversion – North advances the Company’s 4.8 kV to 13.2 kV conversion strategy in an area with aging infrastructure and capacity/operability constraints by funding property acquisition, detailed substation design, material procurement, and overhead pre-conversion design and construction. These activities are part of a multi-year, sequenced plan documented in Exhibit A-23, Schedule M6 and related discovery, and are consistent with Commission-endorsed conversion objectives to improve safety, reliability, and load transfer capability.

The PFD notes that Staff agrees with this project “conceptually.” (PFD, p 177). However, the PFD endorses a flat \$300,000 disallowance (20% of project cost) because “more granular planning detail is needed.” The Company acknowledges an initial mistake in identifying the property acquisition sum in a workpaper but later corrected it.

As with other proposed disallowances, Staff bases its recommendation here on a desire for more granular detail. The record provides substantial project detail consistent with ordinary practice for ratemaking. Exhibit A-23, Schedule M6 contains hundreds of pages of scope and milestone information, and discovery provides additional detail. Requiring even more detailed design, procurement, and construction information, including the “bill of materials with costs, labor, plan, and schedules” for every project is well beyond information typically required in rate cases and would materially expand the record in these cases.²³ (Stowe, 2T 203-204). Staff and

²³ The PFD itself identifies multiple concerns regarding the volume of information that can (or should) be practically considered in general rate cases (See for example, PFD pp. 146 (GPM and RM), 335 (TEP), 382 (calculation of inflation adjustments to O&M expense)). The PFD also notes with approval, that “[t]he Commission agrees with the ALJ that given the ever growing substantial volume of issues raised in general rate cases, it is not possible to address every party’s concerns regarding the methodology DTE Electric developed to prioritize its capital expenditures for distribution projects.” (PFD p. 146, citing Case No. U-21534 Order dated January 23, 2025, p. 97) As the PFD appears

intervenors will always be able to say that more information *could* be provided, but the Commission should be mindful of what is practical and necessary for it to make a determination that investments are reasonable and prudent. Here, where the reasonableness of the project is not even in question, the demand for yet more detailed and granular information should be rejected as inappropriate and unnecessary, and unduly burdensome to all involved.

e. 4.8kV Circuit Conversion (Melvindale) (Sched. B5.4, p. 12, line 56)

Staff recommended a \$360,000 reduction to the 4.8 kV Circuit Conversion (Melvindale) test-year amount asserting that DTE Electric did not provide sufficient support for the project's property acquisition cost, specifically requesting a purchase contract and account treatment. (Staff's Initial Brief, pp 56-57). While acknowledging that Staff "is not questioning the reasonableness and prudence of the project in general," the PFD adopts the Staff's recommendation. (PFD, pp 179-180). The PFD notes that Company witness Stowe testified to an opportunity to purchase property for a new 13.2 kV substation to alleviate area overloading, but that DTE Electric did not supplement this testimony with concrete documentation (e.g., a listing or buy-sell agreement) in discovery or rebuttal and, therefore, treats the support for this cost as insufficient. (PFD, p 180).

The Company disagrees. As explained in the Company's testimony and briefing, Exhibit A-23, Schedule M6 substantiates the Melvindale project's need and scope, including the substation site acquisition to address capacity and reliability concerns; the \$1.5 million property acquisition amount was inadvertently placed on the "Labor" line and should have been categorized as "Other" to reflect capitalized property acquisition consistent with the Uniform System of Accounts-a

to acknowledge at times, demands for perfect insight through unlimited detail and evaluation should yield to what is practical and strictly necessary for a determination of reasonableness and prudence.

correction that was made and explained by Company witness Stowe in rebuttal subsequent to the Staff's raising this concern in its testimony. (Stowe, 2T 195-196; 203-204; Stowe, 2T 62; DTE Electric's Initial Brief, p 64). On this record, there is no dispute as to project necessity and scope or as to the propriety of capitalizing property acquisition; rather, the recommended \$360,000 reduction rests solely on a newly announced preferred form of documentation not previously required²⁴ despite the Company's corrected substantiation of project costs. Given that the Staff does not question the reasonableness and prudence of the project and that the Company resolved in its rebuttal testimony and exhibits the "confusion" it inadvertently created for Staff in the presentation of its materials on direct, the Commission should reject the PFD's recommended reduction and approve the Melvindale conversion funding as requested by the Company.

f. 8.3kV Pontiac Conversion (Sched. B5.4, p. 12, line 61; p. 13, line 101)

MNSC recommended that the Commission disallow \$20.7 million for the Pontiac Conversion, comprised of \$15.8 million for the overhead conversion and \$4.9 million for the underground conversion in the test year, invoking the Liberty Audit's general caution to limit conversions to those required for substation capacity reasons and asserting, without basis, that the Pontiac Conversion is a project that does not need to be executed in the near-term. (PFD, pp 180-181). The PFD adopts MNSC's recommendation, specifically noting:

- (1) whether or not Mr. Stephen's testimony addressed all of the specifics of the Pontiac system, the Liberty Audit, specifically addressed the limitations of the Pontiac circuit and still recommended deferral of the conversion in light of more pressing needs;
- (2) the Commission also addressed the Pontiac conversion in

²⁴ See generally, *Gonzales v United States*, 348 US 407, 413 n 5; 75 S Ct 409; 99 L Ed 467 (1955) ("Those who are brought into contest with the government in a quasi-judicial proceeding aimed at the control of their activities are entitled to be fairly advised of what the government proposes and to be heard on its proposals before it issues its final command"); *Bendix Corp v FTC*, 450 F2d 534, 537, 542 (CA 6, 1971) (vacating agency decision where agency violated the federal Administrative Procedures Act by changing its theory of the case, without notice to the affected party, and then finding adversely to that party); *NLRB v Johnson*, 322 F2d 216 (CA 6, 1963).

particular and directed the Company to provide more support in the form of a BCA if it requests further capital for the Pontiac conversion program; and (3) stories are not data, and should not form the basis for tens of millions of dollars in capital investments that do not need to be expended immediately. (PFD, pp 182-183).

The PFD's recommendation should be rejected. As set out in the record and summarized in the Company's Initial Brief, the Pontiac Conversion addresses concrete system limitations on legacy 8.3kV facilities that cannot be adequately mitigated within the existing system configuration. (DTE Electric's Initial Brief, pp 67-68; Stowe, 2T 101-106; Stowe, 2T 221-223).

The Company notes, again, its concern with the fact that MNSC witness Stephens failed to discuss the limited options for addressing outages on the 8.3kV system, including the fact that it cannot be tied to surrounding 13.2kV circuits in the area. While the PFD appears to give no weight to the Company's concerns related to reliability, the Commission should give weight to the Company's concerns. (DTE Electric's Initial Brief, pp 67-68; Stowe, 2T 221-223). To be clear, as witness Stowe testified, the Company has only one 8.3kV voltage area in its distribution system, and it is in and around the city of Pontiac. The Company acquired the 8.3kV system from CMS Energy in the 1980s. The Pontiac configuration is unique to the Company's overall system and limited to one specific geographic area. The uniqueness of the 8.3kV system and its limited geographic area impact operability and reliability for the Company and customers in this area. The system design also brings unique safety challenges for Company employees operating and maintaining the system. Because of the unique voltage in a limited geographic area, the Company has limited contingency options to support alternate routing of power during planned and emergent outage situations. This results in high risk for a stranded load in the event of an 8.3kV outage event. (Stowe, 2T 101-102). Beyond these very real operational challenges with which the Company must deal, the 8.3kV system is aging, and the equipment is failing and obsolete, so the Company is unable to source replacement equipment. Specifically with respect to substations in the Pontiac

area, failing substation equipment requires significant modification of the existing steelwork to accommodate new standardized equipment. Existing substations lack appropriate safety-related clearances, requiring all circuits to be shut down to perform any maintenance or repairs, thus resulting in more customer outages during maintenance or repairs. When 8.3kV equipment fails, circuit shutdowns lead to extended customer interruptions during outage events and leave the system in an abnormal state for extended periods of time. Further, as new load develops, it is difficult to connect that load to the system due to the obsolete equipment and limited capacity. (Stowe, 2T 102). As witness Stowe testified, the work proposed by the Company will support a reduction of up to 90% in customer minutes of interruption, wire downs, and trouble events through the reconfiguration of 8.3kV infrastructure to current 13.2kV standards. Converting the Pontiac system to 13.2kV will improve system operability and reduce outage restoration time by allowing the Company to restore customers prior to repairing damaged infrastructure, (commonly described as “restore before repair”). (Stowe, 2T 103)

Witness Stowe testified that the Company does not agree with the Liberty Audit’s recommendations related to the Pontiac Conversion Program, specifically because of the significant challenges with the 8.3kV configuration, including the safety, operability and reliability challenges of a small, aged and isolated unique voltage. (Stowe, 2T 104). Company witness Stowe testified that because load on the Pontiac 8.3kV system has gradually increased over the past seven years, the risk of stranded load is higher. (Stowe, 2T 104-105).

As witness Stowe testified, it is the Company’s understanding that MNSC witness Stephens relied heavily, if not solely, upon the conclusions in the Liberty Audit with respect to his recommendation concerning the Pontiac 8.3kV system. (Stowe, 2T 221). In addition to the fact that the Company does not agree with the recommendation of the Liberty Audit related to the

Pontiac Conversions, the Company does not agree with MNSC witness Stephens' characterization of a deferral of this work as "low risk" as, in fact, the risks, already discussed, are very real and very clear. To illustrate this point, Company witness Stowe testified that on July 24, 2025, the Bartlett Substation—in the Pontiac area—experienced a significant failure involving its lone substation transformer and that, as a consequence, more than 3,100 customers were interrupted. To expedite restoration, field crews had to repurpose bushings from a spare transformer with a different voltage. During the interim, generators and portable ISO units were deployed to restore electric service. Nonetheless, the outage extended beyond 13 hours. (Stowe, 2T 222). If this is one of the "stories" to which the PFD refers, the Commission must consider that, through the testimony of witness Stowe—an engineer with more than 20 years of experience in working for DTE, including as a Director of Substation Operations, as the Executive Director of Distribution Operations, and as Vice President of Distribution Operations (Stowe, 2T 34-35)—the Company has provided substantial credible evidence of the operational and reliability risks posed by the Pontiac configuration and the need for this project.

The Company provided project-level documentation describing scope, drivers, and cost, associated with the Pontiac Conversions. (Exhibit A-23, Schedule M6; DTE Electric's Initial Brief, pp 67-68; Stowe, 2T 221-223)

The PFD's reliance on a generalized audit caution and witness Stephens' view of that audit, as well as the PFD's characterization of the Company's engineering explanations as "stories" rather than "data" fail to give due consideration to the substantial credible evidence the Company has presented to support the need, particularly that evidence related to operational and reliability risk. The real field experience on the Company's 8.3kV system described by Company witness Stowe is compelling and makes plain the Company's concerns and desire to provide improved

electric service to its customers. Furthermore, Staff did not take issue with the Company's requests related to the Pontiac Conversions. For these reasons, the PFD's recommended \$20.7 million disallowance should be rejected, and the Commission should approve the Pontiac Conversion funding as filed.

g. Trunk 7105 (Sched. B5.4, p. 12, line 70)

Staff recommends a 20% (\$200,000) reduction to the Trunk 7105 test-year amount "unless the Company provides a complete bill of materials with costs, labor plan, and schedule consistent with the stated milestones." (Staff Initial Brief, p 59). The PFD contends that the Company's rebuttal Exhibit A-50, Schedule QQ3 adds no meaningful detail beyond the initial filing and that Exhibit A-23, Schedule M6 only provides an approximate construction timeline and identifies the budget basis as "Project Management Estimate," with the 2026 projection shown entirely as \$1.0 million in "Total Labor (DTEE & Contractors)" and no materials or other costs. On that basis, the PFD deems Staff's proposed 20% (\$200,000) test-year reduction reasonable and recommends adopting it (PFD, p 185).

The Company disagrees. As witness Stowe explains, DTE Electric has already provided appropriate project-level support for the test year: Exhibit A-23, Schedule M6, pages 238-241, sets out the Trunk 7105 high-level scope and milestone schedule, and the Company's discovery response STDE-6.18b (Exhibit A-50, Schedule QQ3) confirms that during the projected test year the Company will complete detailed engineering, complete manhole inspections, and conduct detailed design (Stowe, 2T 198). Given the documented overload and defined emergency load control solution, Staff's additional request for a complete bill of materials and granular labor plan as a precondition to recovery elevates form over substance and exceeds what is necessary to find the test-year investment reasonable and prudent on this record. Accordingly, the Commission

should reject the recommended \$200,000 disallowance and approve the Trunk 7105 test-year funding as filed.

h. Reverse Power Relay Scheme (Sched. B5.4, p. 12, line 71)

Although Staff agrees that the program is “necessary,” Staff recommended a reduction to the Reverse Power Relay Scheme test-year amount (\$200,000 for 2025 and \$200,000 for 2026) due to limited spend through the first part of 2025, compared to the Company’s projections. (Staff’s Initial Brief, p 60). The PFD adopts Staff’s recommendation on that basis (PFD, pp 185-186).

The Company disagrees. As set forth in witness Stowe’s testimony, the Reverse Power Relay Scheme’s objectives and plans are thoroughly defined and while execution was delayed in 2025, the Company expects full execution of the 2026 program (Stowe, 2T 199; 153; DTE Electric’s Initial Brief, p 64-65). Early-year underspend in 2025 does not demonstrate that the test-year investment will not occur (Chiu, 3T 1141-1143). Because Staff does not dispute the program’s necessity and the record sets out the Company’s test-year plan and expected execution, the Commission should reject the recommended reduction and approve the Reverse Power Relay Scheme test-year funding as filed.

i. Ann Arbor AC Network Conversion (Sched. B5.4, p. 13, line 88); 4.8kV Grosse Pointe Sub and Circuit Conversion (Sched. B5.4, p. 13, line 89); Birmingham (Sched. B5.4, p. 13, line 94); Hilton (Sched. B5.4, p. 13, line 96); BRITN (Sched. B5.4, p. 13, line 98); Pittsfield (Sched. B5.4, p. 13, line 99)

MNSC argued that the Company’s circuit conversion presentation “largely mirrors” the one in Case No. U-21534 and recommended project-specific disallowances totaling \$5.821 million in the bridge period and \$20.642 million in the test year for Ann Arbor AC Network, Grosse Pointe, Birmingham, Hilton, BRITN, and Pittsfield projects, citing the absence of alternatives analyses and limited capacity justification; the AG agreed with MNSC’s recommendations. (PFD, p 186).

The PFD concludes that because Ann Arbor AC Network Conversion, 4.8 kV Grosse Pointe Sub and Circuit Conversion, and Birmingham, are ongoing and should not be terminated midstream, stopping now “could be disruptive” and “could potentially increase costs” (PFD, p 188). While the Company ultimately agrees with the recommendation of the PFD to accept the Company’s requests related to these specific projects, the Company reiterates its position that these projects are necessary to update all substation and distribution equipment to the latest standards for improved safety, reliability, and resiliency at an area level of the grid while also adding capacity to the associated circuits. Conversion projects also reduce outage restoration time by pinpointing the trouble location without requiring line crews to patrol the entirety of the circuit. (Stowe, 2T 40).

The PFD also concludes that that the Commission should approve MNSC’s adjustments of \$152,000 in the bridge period and \$1,084,000 in the test year for the Pittsfield conversion, on the basis that, although there may be some load growth in the City of Ann Arbor, and the Pittsfield substation does serve some City load, the Company’s forecast of load growth in Ann Arbor is speculative and scarce funding should be dedicated to higher-priority projects. (PFD, pp 189-190). The PFD agrees with MNSC that the Hilton Road project could likely be deferred, until such time as DTE Electric provides more support for the need for additional capacity in the Hilton Road area and recommends disallowance of \$9.407 million in the test year for this project, with no disallowance for the bridge period. (PFD, pp 190-191). With respect to BRITN, the PFD cites witness Stephens’ testimony that the BRITN substation is at 72% of firm capacity; well below the 80% threshold where DTE Electric begins planning a system load project and that this does not appear to be a capacity-related project. On this basis, the PFD recommends a disallowance of \$900,000 in the test year. (PFD, pp 191-192). Finally, the PFD agrees with witness Stephens’

recommendation that DTE Electric should collaborate with Staff and other interested parties to develop more concrete planning protocols and guidelines to inform the pace of circuit conversions and that the Commission could consider directing DTE Electric to form a workgroup or collaborative to this end. (PFD, p 192).

The Commission should reject the PFD's recommendations related to the Pittsfield, Hilton Road, and BRITN conversions for the following reasons. First, regarding the Pittsfield project, the PFD's conclusion that the conversion is not needed in the near term relies on MNSC's incorrect argument that "there is no credible capacity justification for the Pittsfield conversion project". (PFD, pp 189-190). The PFD acknowledges the Company's reiteration of the information provided in the Company's application, which supports the need for the Pittsfield project by pointing out that "adjacent substations (Crown and Wolverine) are over their substation firm ratings" which of course limits the jumpering capabilities for emergency restoration. (Exhibit A-23, Schedule M6, pp 319-322). The dismissal of the Company's load growth forecast for Pittsfield as "speculative", disregards the operational reality that any load growth would only exacerbate existing area overloads. Second, regarding the Hilton Road project, the PFD erroneously quotes witness Stowe's cross examination by stating that witness Stowe clarified that the DDO limit for 13.2kV circuits "is based on guidelines that the U.S. Department of Agriculture uses to loan money to rural electric cooperatives." (PFD, p 190). Review of the record shows that the PFD is quoting a question that was asked of witness Stowe during cross examination, however, witness Stowe did not clarify this in the affirmative. (Stowe, 2T, 273-274). Further, the PFD relies on MNSC's opinion that there is no capacity constraint in the Hilton Road substation area and that DTE Electric is "rushing" conversions, which disregards witness Stowe's direct testimony and exhibits indicating that the Hilton Road project is in Phase 2 with Phase 1 already having constructed a 120/13.2kV substation

and Phase 2 presented in the instant case being a continuation of this work (Stowe, 2T 59; Exhibit A-23, Schedule M6, p 311). Witness Stephens' premise that DTE Electric is "rushing" conversions and has not shown capacity need for the identified projects is simply incorrect. As Company witness Stowe explained, the Company will continue to plan and execute proposed 4.8 kV conversions over the next five years precisely because they are capacity-driven, and projects outside that window will be proposed only where supported by a benefit-cost analysis, including capacity needs (Stowe, 2T 224; DTE Electric's Reply Brief, pp 53-56). As testified to by Company witness Stowe, the benefits of the 4.8kV Conversion Program (in which these projects fall) are—in addition to increased area capacity—enhanced safety by proactively mitigating an energized downed wire, improved reliability, resiliency, accessibility, and system maintenance efficiencies through infrastructure consolidation and decommissioning of aged equipment beyond useful life. (Stowe, 2T 55-59). Table 2 in witness Stowe's direct testimony provides a summary for the specific projects, including those for which a disallowance is recommended by the PFD. (Stowe, 2T 60-66). As Company witness Stowe testified, the Liberty Audit recommended that the Company "limit 4.8kV conversions to those necessary for substantial capacity reasons." (Stowe, 2T 67). As testified to, the 4.8kV conversion projects, including those recommended for disallowance, are necessary for capacity reasons, (Stowe, 2T 67-69), in addition to other reasons. (Stowe, 2T 69-70). Regarding the BRITN project, the PFD also incorrectly recommends a disallowance of \$900,000 in the test year, while the Company only requested \$260,000 in the test year for the BRITN project. (PFD, p 191; See Exhibit A-12, Schedule B5.4, p 13). Clearly, the recommendation for disallowance is erroneous and should be rejected.

For the Ann Arbor AC Network, Birmingham, Hilton Road, BRITN, and Pittsfield projects, Exhibit A-23, Schedule M6 provides project-level documentation showing each is driven

by capacity (and related operability/reliability) needs in its area and addresses potential service-interruption risk: Ann Arbor AC Network (Exhibit A-23, Schedule M6, pp 283-286); Birmingham (Exhibit A-23, Schedule M6, pp 303-306); Hilton Road (Exhibit A-23, Schedule M6, pp 311-314); BRITN (Exhibit A-23, Schedule M6, pp 315-318); and Pittsfield (Exhibit A-23, Schedule M6, pp 319-322). On this record, the Commission should reject the PFD's project-specific disallowances premised on a narrow, point-in-time loading view and instead credit the Company's capacity-driven planning and detailed project support.

Additionally, in response to the PFD's recommendation at page 192 that the Commission should direct DTE Electric to collaborate with Staff and other interested parties to develop more concrete planning protocols and guidelines to inform the pace of circuit conversions, the Company has no concerns regarding working with Staff to ensure the concerns and questions of Staff are addressed. However, the Company strongly disagrees with the PFD's recommendation for a working group related to circuit conversions. As explained in the Company's case, circuit conversion projects concern safety, reliability, resiliency, accessibility, and system maintenance—matters very much encompassed within the Company's obligation to provide safe and reliable operation of its system. The Company has defined the process through which new conversion projects will be validated (Stowe, 2T 224) and interested parties will have the opportunity to participate in the distribution grid planning process and to participate in proceedings, such as this one, that involve investigation into the reasonableness and prudence of the Company's investments. The Company stresses for these reasons that the Commission should not accept this recommendation.

5. System Loading Projects

a. Staff Adjustment (Grenada) (Exhibit A-12, Sched. B5.4, p. 13, line 108)

Company witness Stowe described the Grenada project, a system loading project, as follows:

The first step of the project was to rebuild and convert a portion of an adjacent Prospect substation circuit to deliver improved reliability from the rebuild, but also mitigate an overload at Prospect substation which was over 100% of firm rating and exceeded 100% of its emergency rating in 2018 (4.2 MVA loading vs 4.1 MVA rating). To address the circuit overloads, approximately half of a Prospect substation circuit has been transferred over to a Grenada substation circuit as of 2024 (summer loading of 2.1 MVA remains at Prospect). To support projected circuit/area needs, construction of a new Grenada substation is planned and will increase capacity by 77% versus the existing Grenada substation, providing capacity for continued growth and mitigating circuit overloads. Finally, additional planned circuit conversions and establishment of additional circuits will enable installation of loop schemes and circuit automation, none of which are possible without the capacity delivered in the system loading project. When fully implemented, the project is anticipated to deliver an 88% improvement in reliability versus three-year (2020-22) historic SAIDI for the area.

(Stowe, 2T 113).

Staff witness Shi testified that while Staff supports the Grenada project, Staff has concerns about previous underspending on the project and recommends adjustments for 2025 and 2026 based on annualizing the five-month 2025 investment. This resulted in a proposed disallowance by Staff of \$10,266,233 in 2025, and \$6,233,274 for the 2026 test year. (Shi, 5T 5028-29).

Company witness Stowe acknowledged the delay in 2025, which was the result of permitting issues, but testified that the 2026 scope of work is expected to be completed. (Stowe, 2T 201).

Ultimately, the PFD concludes, “in light of DTE’s overly optimistic projections and resulting underspend from 2023-2025[,]” Staff’s recommended adjustments should be adopted and suggests that if the Company catches up on this project, the Company can request approval of additional amounts in a future rate case. (PFD, p 201).

The Company disagrees with this recommendation because, as explained by witness Stowe,

the Company's execution of the project was delayed in 2025 due to permitting obligations imposed by the local permitting jurisdiction. The Company worked through those obligations in 2025, and does not anticipate any delay to the execution of the 2026 scope of work. (Stowe, 2T 201). Thus, while the Company acknowledges the delay in 2025, the Company reasonably anticipates timely completion in 2026. (Stowe, 2T 201). Because this project is anticipated to deliver an 88% improvement in reliability versus three-year (2020-22) historic SAIDI for the area, (Stowe, 2T 113, 117-118), the Company respectfully requests that the Commission give weight to the testimony and exhibits of witness Stowe over the concerns expressed by Staff and disregard the recommendation in the PFD.

6. Technology and Automation

The Technology & Automation Pillar is one of four pillars of DTE Electric's Distribution Operations (DO) investments. The investments the Company is making in Technology & Automation are part of its multi-year strategy to rebuild, modernize, and automate its approximately 46,000 miles of circuits. These investments will position the Company to fully utilize modern distribution system technology to achieve greater safety, reliability, and efficiency to the benefit of customers. (Rademacher, 3T 745-746).

a. Conservation Voltage Reduction/VoltVar Optimization (Sched B5.4. p. 14, line 2)

The PFD recommends that the Commission adopt Staff's proposed reduction of \$7.1 million for the 2026 test year for the Conservation Voltage Reduction (CVR) and Volt Var Optimization (VVO) program. (PFD, pp 210-211). The PFD finds that the Company insufficiently defined its planning for the 2026 CVR/VVO spend, including numbers of circuits and capacitors and unit cost. (PFD, pp 210-211).

The Company disagrees with the PFD. The CVR/VVO program is a key component of the Grid Automation category of Technology & Automation DO investments. The program replaces end of life pole top capacitor controls with modern SCADA enabled controls that include sensors and asset health measurement. (Rademacher, 3T 782-783). These devices monitor and adjust the reactive power flow on the system and optimize system voltage to reduce total energy usage, improve grid efficiency, and provide better power quality for customers, especially on the hottest days of the year. (Rademacher, 3T 936-937).

DTE Electric witness Rademacher explains the Company's plan to install capacitors on 70 circuits in 2026 at a cost consistent with typical expectations for projects of similar scale and investment level. (Rademacher, 3T 937). While the pace of execution was intentionally slowed from 2023 into 2025, the PFD's recommendation fails to account for the clear plan articulated by the Company for project execution:

From 2025 onward the program will focus on replacement of 100% of all poletop capacitor and regulator controllers with SCADA enabled controls, analyzing all circuits for appropriate capacitor and regulator placement, moving and supplementing capacitor placement where needed. The capacitor control replacement will have an added value of providing sensing capability at each location which will be used by the ADMS. This will be done while maintaining a low, but sustainable schedule of substation LTC upgrades each year that allows for appropriate coordination and shutdowns. Substation LTC control upgrades to support CVR/VVO functionality will be built into design standards and replacements. This will result in a wider deployment of smaller initial benefits because most circuits will be optimized with the pole top devices alone, but this will allow for increased visibility into the system response to VVO through the ADMS and get critical data back to planning tools to verify CVR opportunities. This work will be coordinated with 4.8KV conversion and replacement and the circuit automation programs to ensure that device is placed where needed. The program will also investigate the use of circuit capacitors as part of the optimization and alternatives to large station capacitors. Pole top regulator SCADA controls and smart inverter controls will also be added to the program over the next 5 years. Additional work in the program will include development of sufficient tracking algorithms, analysis and reporting to measure benefits vs expected results and improvements to internal planning tools to allow CVR/VVO to continue to be

operated as circuits change due to load changes, circuit reconfiguration and DER installations.

(Exhibit A-23 Schedule M8, page 241). This explanation fully supports the Company's plans and pace of CVR/VVO program deployment and the PFD's conclusion that DTE Electric provides "vague, if not entirely circular" support does not appear to consider this explanation. (PFD, p 211). Customers will benefit from the energy savings (i.e., customers will buy fewer kWhs), improved power factor, and better voltage regulation enabled by the program. If the Company does not execute the CVR/VVO program, it will lose the opportunity to achieve these energy savings and to optimize circuit power flow and customer voltage. (Rademacher, 3T 784-785, 938). Faced with the Company's clear plans for CVR/VVO deployment in 2026 and uncontroverted benefits for customers, the PFD's suggestion that "[i]f DTE installs more units in 2026, it may request recovery in a future rate case" (PFD, p 211) does not withstand scrutiny.

The Commission should therefore reject the PFD's recommendation and approve the Company's proposed 2026 investment for the CVR/VVO program.

b. Distribution Automation (Reclosers)

The PFD recommends that the Commission adopt Staff's recommended disallowance of \$62,253,571 for 2025 and reduction of \$72.0 million for 2026 for the Distribution Automation (DA) Program. (PFD, p 224). The PFD agrees with Staff and intervenors that, prospectively, the Company's DA program should be limited to safety reclosers, and that additional reliability DA should await a more complete, detailed analysis that accounts for the effects of maintenance programs (e.g., tree trimming and PTMM). (PFD, pp 222-223). The PFD specifically highlights intervenor testimony that while efforts like tree trimming and PTMM can prevent outages, DA mitigates outages but does not prevent them, "making expensive DA investments unnecessary." (PFD, p 223). To support the proposed disallowance of projected spend, the PFD notes its concerns

that (1) despite the Company’s longstanding emphasis on safety benefits, only about one-third of proposed DA funding is for safety reclosers with the remainder dedicated to reliability reclosers, and (2) the Company proposes to lengthen, rather than shorten, tree-trimming cycle times contrary to the Liberty Audit’s recommendations. (PFD, p 223). The PFD “does not find that reliability DA investments made to date should be disallowed, as some parties seem to suggest. Indeed, the circuits on which the reliability reclosers are installed may provide important data for future analyses.” (PFD, p 224). However, going forward the PFD recommends focusing exclusively (or nearly exclusively) on safety DA. (PFD, p 224). Finally, the PFD agrees with Staff in questioning the Company’s ability to execute this program at forecasted levels, based on the Company’s suggested modification to Staff’s disallowance, which it suggests “indicates that the Company may also have doubts about its ability to deploy the number of reclosers it forecasted.” (PFD, p 224).

The Company disagrees with the PFD. The DA program, initiated in 2021, is designed to enhance outage response and to improve electric grid reliability, particularly during severe weather events. This improvement is achieved through the deployment of intelligent field devices—including sensors, switches, and reclosers—designed to enable flexible sectionalizing and automatic circuit reconfiguration. These capabilities allow for faster isolation of faults and restoration of service, particularly during outage events caused by physical damage such as downed wires. For 2025, the Company proposed to spend \$105,625,000 on the program; for 2026, the Company proposed to spend \$115,625,000 on the program. (DTE Electric’s Initial Brief, pp 71-72; DTE Electric’s Reply Brief, p 59).

The Company appreciates the PFD’s finding that DA reliability investments made to date should not be disallowed, and its recognition of the valuable data that circuits on which reliability

reclosers are installed can provide. (PFD, p 224). However, the PFD's recommendation fails to account for the substantial record evidence supporting approval of the full DA investment.

Regarding the PFD's distinction between reclosers that mitigate outages and inspection and maintenance activities that prevent outages, (PFD, p 223), and its concern with the ratio of safety reclosers versus reliability reclosers, (PFD, p 223), the Company fully addressed these issues in its Initial Brief. (DTE Electric's Initial Brief, pp 75-76). In addition to programs that target the root causes of outages, such as tree trim and PTMM, the Company's overall reliability plans address the short-term need to reduce the potential hazard of downed energized wires, reduce the number of customers impacted by outages through automated and flexible grid reconfiguration, and improve the speed of restoration after a storm. The BCA presented by Company witness De Stigter clearly demonstrates that the proposed investments in DA will deliver meaningful value to customers by reducing the duration of power outages. (De Stigter, 4T 1858-1859; 1864; 1897-1898). The DA and PTMM BCAs were not developed independently, without consideration of the relationship between the programs. The BCA models deployed DA first and then PTMM, with results showing both programs are beneficial. (Rademacher, 3T 919-920).

Additionally, Company witness De Stigter further demonstrated the customer benefits of DA even when PTMM and tree trim are first completed on circuits (De Stigter, 4T 1897-1898). The Company strongly supports deploying DA as part of a comprehensive suite of programs designed to enhance customer reliability. The complexity of today's grid challenges demands an integrated approach, and DA is a critical component in delivering effective, system-wide solutions. While programs such as tree trim and PTMM address the root causes of specific outage types, they are, by themselves, unable to prevent all outages. Furthermore, in many cases, the implementation of root-cause-targeting programs will entail a substantially longer deployment period across the

entire system. The DA recloser program is targeted at short term outage mitigations once an outage has occurred, allowing the grid to be safely, quickly, automatically, and flexibly restored, minimizing impacts to customers. (Rademacher, 3T 921).

Additionally, Company witness Rademacher presented evidence of the benefits achieved by the DA program thus far, including improved safety in wire-down events, increased reliability as shown by fewer outages and shorter outage durations, and improved operating efficiencies from better system monitoring and control. (Rademacher, 3T 763-764). For these reasons, the Company also disagrees with the PFD's reliance on MNSC's assertion that the Company's position "ensures a double-hit to residential customers" and the PFD's characterization of reliability recloser investments as "unnecessary." (PFD, p 223). These conclusions over-simplify the Company's strategy for improving safety and reliability; both the investment in preventative maintenance and the investment in safety and reliability reclosers are necessary and appropriate to achieve safety and reliability benefits for customers. There is actually a resulting "double benefit to residential customers" from the Company's plan – a combination of reduced total outage numbers and a reduced size and duration of those outages that do occur. This fact is confirmed by the normalization analysis on the DA BCA performed by Company witness De Stigter. (De Stigter, 4T 1896 -1899).

Regarding the PFD's finding that "additional investments in DA for reliability purposes should await a more complete and detailed analysis of benefits," (PFD, pp 222-223), as discussed above, the BCA presented *in this case* provides the Commission a complete, detailed analysis of the benefits of reliability closers, and did account for the effects of PTMM and other investments that reduce outages. Going forward, the Company will comply with the Case No. U-21305 Audit Order's request that additional analysis be included in the next DSP filing on June 30, 2026.

(Rademacher, 3T 913). Continuing with these installations in the interim provides both safety and reliability benefits for customers as shown by the BCA. In addition, these investments were supported by the Commission for both the 2024 rate case and IRM for 2025 – 2026. (Rademacher, 3T 913).

The PFD also opines that “[i]n the long run ... capital investments, like DA, are far more costly to ratepayers” than O&M expense, and that “[g]iven the significant and valid concerns about energy affordability for DTE’s customers, an appropriate balance must be struck between capital and O&M.” (PFD, pp 223-224). The PFD finds that the Company’s proposed investments for reliability DA “do not achieve that objective.” (PFD, p 224). DTE Electric recognizes and has addressed in briefing the significant issue of customer affordability. (DTE Electric’s Reply Brief, pp 223-225). However, the Company disagrees with the PFD and submits that its proposed DA investments are reasonable and prudent and do achieve the appropriate balance suggested by the PFD between capital and O&M for the reasons discussed in witness Rademacher’s testimony and DTE Electric’s Briefs.

Finally, concerns regarding the Company’s ability to execute the program at the forecasted level are unfounded. (DTE Electric’s Initial Brief, pp 72-73; DTE Electric’s Reply Brief, p 60). The Company had already exceeded Staff’s year end projection for 2025 at the time it filed rebuttal testimony in this proceeding. (Rademacher, 3T 908). Further, the Company outlined plans to mobilize resources to ramp-up installations for 2025 and 2026; aligning with the Company’s projected total installations and demonstrating that the Company is planning for and executing the accelerated pace of investment. Continuing into 2026, Company witness Rademacher explains the Company’s plans to ramp up to achieve the investment levels proposed in this proceeding. (Rademacher, 3T 908). The PFD’s finding that “[t]he fact that DTE suggested a modification to

Staff's disallowance is telling, and it indicates that the Company may also have doubts about its ability to deploy the number of reclosers it forecasted in its plan," (PFD, p 219), misapprehends the point made by witness Rademacher. He testified that

Given that the Company has already exceeded the level of year-end investment estimated by Witness Shi, the Company has prepared two alternative methodologies for forecasting the 2025 DA program investment in Exhibit A-53, Schedule TT1. These are: (1) start with the 7-month 2025 investment of \$25.3 million and apply a linear monthly investment pattern similar to Witness Shi, but projecting forward using July investment levels at \$11.3 million per month, to estimate a year-end total of approximately \$81.7 million; and (2) following 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.

(Rademacher, 3T 906). This testimony does not suggest that there may be some impediment to the Company's ability to achieve its DA program investment levels ; to the contrary, it demonstrated that even using Staff's linear methodological approach to project of the DA program spend during 2025 using the proper updated investment amounts supports an annual total DA program investment much closer to what DTE Electric intends to spend. And notably, witness Rademacher concludes by stating that the Company's requested amount "provides the most accurate forecast."

Based on the foregoing, the Commission should reject the PFD's recommendation and approve full funding of the Company's 2025 and 2026 investments in the DA recloser program.

c. Line Sensors

The PFD recommends that the Commission adopt Staff's proposed disallowance of \$2.6 million in 2025 and reduction of \$845,623 in the 2026 test year for the Line Sensor program, because the Company's briefing did not address this specific item. (PFD, pp 226-227).

The Company (and the record) disagrees with the PFD. The Company's Initial Brief expressly addressed the line sensor disallowance proposed by Staff:

With respect to the Distribution Sensing and Monitoring program, witness Shi claimed that only a small fraction of the projected 2025 budget was spent in the

first four months, and Staff assumed the Company prioritized other urgent projects or lacked sufficient manpower to execute the planned expenditures. Based on this, she recommended a disallowance of \$2.6 million in 2025 and \$845,623 in 2026. (Shi, 5T 5002). Witness Shi's assumptions are inaccurate because they rely on a linear extrapolation of spending from just the first four months of 2025. This approach overlooks several key factors like seasonal construction patterns, project management dynamics which follow a non-linear timeline and vary throughout the year and, finally, installation and purchasing cadence which does not align with a simple monthly average. (Rademacher, 3T 959-962). For these reasons, her recommendation should not be accepted by the Commission. (DTE Electric Initial Brief, p. 81)

Since the PFD's basis for accepting Staff's proposed disallowance was the incorrect conclusion that the Company did not address Staff's proposed disallowance in briefing, the PFD's recommendation can and should be rejected on that mistaken conclusion alone. Additionally, however, the Company's evidence fully supports cost recovery of these items so the Commission can approve DTE Electric's request on that basis as well. The PFD itself confirms the existence of the Company's evidence (See PFD pp. 224-227 citing Company witness Rademacher, 3T 785-788, 960-961 and noting Staff's acknowledgement of "*the significant value of the program.*") Additionally, the Company's Reply Brief incorporates its Initial Brief and provides that "[l]ack of discussion by DTE Electric to separately address every issue or position suggested or inferred by any party should not be deemed to constitute agreement by DTE Electric." (DTE Electric Reply Brief p.3) Nevertheless, the Company herein clarifies and reconfirms its disagreement with all recommendations to disallow line sensor expenditures and requests that the Commission reject the PFD's recommended disallowances with respect to line sensors.²⁵

Through this program, the Company will install overhead system sensors, which witness Rademacher described as the "eyes and ears of the grid," to detect outages and faults on the

²⁵ When reviewing a PFD in response to exceptions filed by a party, the APA empowers the Commission to exercise all the power that it would have if it had presided at the hearing for cross examination. MCL 24.281(3). Thus, the Commission retains the power to modify the PFD, so long as it does so based on the evidence in the record. Don LeDuc, *Michigan Administrative Law* § 6:69, at 478 (2d ed. Supp. 2010).

overhead and underground lines and send the data directly to the ADMS to speed restoration. (Rademacher, 3T 786-787). The Company proposed to install approximately 450 overhead sensors and 800 underground sensors in 2025 and another 450 overhead sensors and 1,100 underground sensors in 2026. (Rademacher, 3T 787-788). In his rebuttal testimony, Company witness Rademacher explained that Staff's calculation of its proposed disallowance, which was based on extrapolation of four months of spending, overlooked a number of factors that impact the program cost that do not line with a simply monthly average. (Rademacher, 3T 960-961). Witness Rademacher also noted that Staff did not recognize that there are different unit costs for overhead versus underground sensors, and provided evidence showing that the Company will spend the requested amount on the program by the end of 2026. (Rademacher, 3T 961).

d. SCADA Historian

The PFD recommends that the Commission should adopt Staff's proposed reduction of 50%, or \$2.5 million, for the SCADA Historian project for the 2026 test year. (PFD, p 230). The PFD finds the information provided in Confidential Exhibit A-53, Schedule TT5 in support of the Company's request to be unclear and insufficient to substantiate the full request. While acknowledging Staff could have sought additional discovery, the PFD notes the Company also had the opportunity to supply fuller support in rebuttal. (PFD, p 230).

The Company disagrees with the PFD. Evidence recognized by the PFD states that the SCADA Historian is an essential element of the distribution SCADA ecosystem that provides long-term storage and retrieval, system performance and telemetry analytics, and the baseline for loading and voltage statistics. (PFD, p 229; Exhibit A-23, Schedule M7, p 48). The basis of the \$5 million request has been disclosed in reasonable detail in Confidential Exhibit A-53 Schedule TT5. (Rademacher, 3T 953). Further, with the single multi-year licensing investment in 2026, the

Company can lock in the cost to prevent any unexpected increases. (Rademacher, 3T 953). In rebuttal, the Company identified the vendor and submitted the basis for the cost. (Rademacher, 3T 953). Based on the foregoing, the Commission should reject the PFD's recommendation and approve the full requested 2026 funding for the SCADA Historian project.

e. Mobile Equipment Replacement (Exhibit A-12, Schedule B5.4, p. 14, line 38)

The PFD recommends that the Commission adopt Staff's recommended reduction of \$1.750 million in the 2026 test year for the Mobile Equipment Replacement program. (PFD, p 232). The PFD finds that the Company's argument "that these devices are vital to field operations and must be updated on a regular schedule is belied by the fact that the Company deferred replacements for several years and now wishes to play catch up." (PFD, pp 231-232).

The Company disagrees with the PFD. DTE Electric deploys thousands of mobile devices for field workers; these devices are replaced on a six-year cycle, with approximately 1/6 of all devices replaced each year. Updating the devices to current technology maintains reliable access to critical applications and improves the Company's ability to respond to service needs and shortens outage restoration times. (Rademacher, 3T 893). The 2026 request reflects the first major replacement cycle after a multi-year pause (2023-2025) and addresses more than 1,900 field devices that are outdated or past end-of-life. As Company witness Rademacher explains, deferring half of these replacements would prolong reliability and cybersecurity risks. (Rademacher, 3T 954-955; DTE Electric's Initial Brief, p 80). The Staff's and PFD's reliance on the fact that the replacement schedule was paused is misplaced and at cross-purposes with the goal of making prudent investments to provide reliable service, as Company witness Rademacher has provided uncontroverted evidence that these devices are in need of replacement now. On this record, the

Commission should reject the PFD's recommendation and approve the requested 2026 funding for the Mobile Equipment Replacement program.

f. Mobile Timesheets and Vegetation Management Replatform

The PFD notes that after initially recommending reductions to the Mobile Timesheets and Vegetation Management Replatform programs, Staff reviewed the Company's rebuttal and states that it is satisfied with the requests, and it withdraws its disallowances. (PFD, p 232). The Company's Reply Brief also noted Staff's recommendation that the Commission approve the full requested \$1.4 million in 2026 for the Mobile Timesheets program and \$3.2 million in 2026 for the Vegetation Management Replatform program. (DTE Electric's Reply Brief, p 61). The PFD makes no findings or recommendations with regard to these programs. Based on the foregoing, the Commission should approve the full requested funding for 2026 for these programs.

7. Distributed Energy Resource Management System

Company witness Rademacher explains that the grid of the future will need to be updated in order to incorporate new technologies, including distributed energy resources (DER) such as solar and BESS. DTE Electric proposes capital investments to develop a Distributed Energy Resource Management System (DERMS), including \$1.5 million in the bridge period and \$2.8 million in the 2026 test year. These investments would enable the Company to implement a utility DERMS that consolidates DER and demand response (DR) program data, interfaces with the advanced distribution management system (ADMS), and builds toward forecasting, optimization, constraint management, and distribution system operations/transmission system operations coordination, including to support MISO's implementation of FERC Orders 841 and 2222 (Rademacher, 3T 835-839; Exhibit A-12, Schedule B5.4, p.15, line 45). DTE Electric also plans capital investments of \$12.0 million in the 2025 bridge period and \$5.4 million in the 2026 test

year for Grid Edge Insights and New Technology, a sub-category of Grid Automation investments. Mr. Rademacher explains that these investments will consolidate the learnings from the Company's non-wire alternatives (NWA) pilot projects into a consistent platform and enable DTE Electric to develop a standardized gateway platform that will simplify the integration of DER systems to ADMS and the future DERMS. (Rademacher, 3T 800). This includes streamlining interconnection of customer DER as substantial portions of the communication and control are pre-designed inside the gateway. (Rademacher, 3T 800). Witness Rademacher testified that the Company has made progress on its Grid Edge Insights and New Technology projects, including 2024 investments to expand the solar and storage testbed for testing interconnection gateways and battery trailer systems. He further detailed the investments planned for 2025 and 2026 and testified that these investments will increase the Company's ability to integrate DER into grid operations and allow for more flexible DER operation. (Rademacher, 3T 801-802).

CEO witness Kenworthy urged the Commission to defer DERMS and Grid Edge Insights and New Technology spending until after the Company files a comprehensive business case with a benefit-cost analysis and stakeholder process (mirroring directives to Consumers Energy in Case No. U-21585 requirements) and to tie any approval to a requirement to file a virtual power plant (VPP) business case and plan. (Kenworthy, 4T 3611-3614, 3620-3621). MEIU witness Albers also supports conditioning approval of these planned investments on a business case and asks the Commission to direct DTE Electric to ensure interoperability with third-party "edge/fleet" DERMS. (Albers, 5T 4058-4059).

Specific to DERMS, the PFD states that it agrees with CEO and MEIU's suggestion to disallow the requested DERMS capital (\$1.5 million bridge and \$2.8 million test year) and to condition any future DERMS funding on a more comprehensive justification of the Company's

DERM's proposal, business case (aligned to the Commission's directives to Consumers Energy in Case No. U-21585) that includes a BCA, stakeholder input, and analysis of VPPs

The Company disagrees and takes exception to this recommendation. DERMS is a prerequisite platform, not a discretionary overlay, for safe, reliable DER integration and for future customer-facing programs. Simply put, withholding capital investments to deploy these foundational capabilities would delay compliance-driven functions and materially hinder program enablement that intervenors themselves seek. (Rademacher, 3T 938-942). The PFD appears to acknowledge this, commenting that "DTE is in the early stages of implementing foundational investments for the development of its DERMS infrastructure[.]" and that "this case involves no dispute as to the necessity of DERMS[.]" (PFD, p 241). The Company has identified specific near-term DERMS spending plans (software licensing, program and configuration database, and initial interfaces) to centralize program management and tie DER/DR to ADMS and market systems, with subsequent phases adding forecasting/optimization and constraint automation. (Rademacher, 3T 838-839). These near-term investments are reasonable and prudent and, in fact, fully align with the PFD's desire that "early investments [to enable DERMS] are properly focused on creating an adaptable and versatile platform that will enable future integration of diverse and emerging technologies." (PFD, p 241). The PFD discounts witness Rademacher's testimony on the need for and scope of planned DERMS investments proposed in this case and appears to principally rely upon a Commission determination in early 2025 regarding investments proposed by Consumers Energy in its rate case. (See PFD, p 241 *citing* March 21, 2025 Order in Case No. U-21585, pp 117-118). Accordingly, the Commission should reject the PFD's disallowance and approve the requested DERMS capital.

8. Grid Automation Telecommunications

DTE Electric witness Rademacher explained that grid automation telecommunications “refers to the use of telecommunications technology as an essential enabling component in the automation of electrical power grids,” integrating communications with the distribution network to enable real-time monitoring, control, and management. (Rademacher, 3T 767-768). Witness Rademacher described this network as a “backbone system” providing two-way communications with the System Operations Center and outlined the current state and planned repairs/replacements, identifying work completed during the 2023-2024 period and plans for 2025 onwards as shown in Exhibit A-12, Schedule B5.4 (p. 14) (Rademacher, 3T 774-776). The Company noted it is only exploring a potential Company-owned LTE network in the future, not requesting approval of any capital spending for such a program in this case. (Rademacher, 3T 776). DTE Electric witness De Stigter presented BCA and supporting testimony on the Company’s planned Grid Automation Telecommunication Approach, evaluating five scenarios—current communications, public LTE (current capacity), private LTE/fiber (current capacity), public LTE (expanded use cases), and private LTE/fiber (expanded use cases) — and concluded the private LTE alternatives have the lowest life-cycle costs under both current-capacity and expanded-use cases, with added benefits in reliability, security, scalability, and avoiding carrier fee escalation (De Stigter, 4T 1854-1856; 4T 1860-1862). MNSC first recommended a \$15 million disallowance tied to a future Company-owned cellular network, but after review of the Company’s rebuttal, modified its position to request that any future utility-owned LTE proposal include a comprehensive assessment comparing utility and public networks with detailed economic, technical, operational, security, and reliability showings (MNSC Initial Brief, p 117).

The PFD finds the Company’s showing responsive to the Commission’s prior directive in

its Case No. U-21534 Order²⁶ and recommends approving the Company's proposed telecommunications expenditures in this case. (PFD, p 243). The PFD also recommends the Commission adopt MNSC's proposal that, if the Company later seeks approval to develop a Company-owned LTE network, the Company should update and refine its BCA so that private-versus-public LTE costs and benefits are fully captured (PFD, p244). While DTE Electric witness Rademacher demonstrates why MNSC witness Alvarez's critiques of consolidating existing systems into a unified private LTE network are not well founded, the Company does not object to the PFD's recommendation to present an updated BCA in the future if it requests to recover the cost to develop a Company-owned LTE network.

F. Demand Response

Company witness Leuker presented DTE Electric's Demand Response (DR) programs and projected expenses as set forth in Exhibit A-12, Schedule B5.6. (Leuker, 3T 1353). The PFD notes that no party contested the Company's CoolCurrents and SmartCurrents programs and did not further opine on those programs. (PFD, p 251). The Company's exception to the PFD's findings with respect to other DR programs is discussed below.

1. Commercial and Industrial Battery Pilot

The Company's Commercial and Industrial (C&I) Battery Storage Pilot is a behind-the-meter (BTM) battery energy storage system (BESS) intended to be located at two customer sites with the goal of achieving peak demand shaving or shifting during demand response events. (Leuker, 3T 1353). The PFD adopted the recommendation of Staff and MEIU to disallow \$508,000, which represents the cost of the pilot's second battery, on the grounds that the Company

²⁶ Case No. U-21534 Order dated January 23, 2025, p. 154; (Rademacher, 3T 932)

was unable to find a second *external* customer to participate in the program. (PFD, p 255, emphasis added; Matthews, 5T 5084-5086; Sherman, 5T 4033; 4037).

The Company disagrees with the proposed disallowance and, in particular, the PFD's position that it is "virtually self-evident" that the second participating customer must be external. (PFD, p 255). As a threshold matter, there is nothing in the Commission's past orders or in the Company's filings specifying that the second customer must be external, and the Company has identified an appropriate internal customer for the second battery that will contribute to achieving the planning objectives of the C&I battery pilot program. While the second battery will be deployed at a Company-owned site, it is separate from the NWA pilots and will be housed in a controlled environment that allows for testing on the grid in a safe manner, with equipment that can perform repeatable scenarios of expected events. (Leuker, 3T, p 1382). This will allow the Company to pursue (1) experimentation and stacking of different energy storage use cases; (2) evaluation of compensation models; and (3) answering key questions around wholesale market integration (as contemplated by Case No. U-21032). Witness Leuker explains that the Company will also be able to address key objectives of the pilot program, including, among other things, gaining operational experience on battery installation, management, and control interfaces and evaluating the effectiveness of the BESS to achieve system peak demand reduction when a DR event is called by the Company, (Leuker, 3T pp 98, 1382). With one external and one internal customer poised to participate in the pilot program, the Company is well positioned to test the proposed C&I program in a small setting and gain takeaways that will be critical to ensuring the program's success on a wider scale. For this reason, and as shown in the record, the Commission should reject the proposed \$508,000 disallowance and approve the full expense for the C&I Battery Pilot, including expenses for both batteries.

G. Information Technology (IT)

1. Specific IT projects

a. Customer Insight Platform Application Health

The PFD recommends the Commission adopt Staff’s proposed adjustment of \$4.3 million in capital expenditures for the 2026 test year for the Customer Insight Platform Application Health project and \$100,000 in related O&M. (PFD, p 268). The PFD relies on the age of the project and asserted continued low customer engagement and participation and concludes that the Company “failed to establish sufficient or sustained interest in the project to warrant expenditure.” (PFD, p 268).

This project supports vendor-provided annual maintenance, upgrade, and other support services, key architecture components, and cloud computing services to maintain user-facing functionalities for the DTE Insight mobile app and Energy Bridges, as well as the BillWise AI tool pilot and the Bill Management tool. (Ambrose, 4T 2265-2266, 2362-2263).

The Company disagrees with the PFD. While the PFD focuses on the number of customers participating in these offerings, the Company’s primary reason for investing in this project was to realize its numerous benefits that continue to support approval of its costs, as well as enabling enhancements to the Bill Management tool. (DTE Electric’s Initial Brief, pp 108-109). The Customer Insights Application Health project is the backbone of multiple customer facing platforms, Bill Management, BillWise AI, the DTE Insight App, and the Energy Bridge that demonstrably reduce contact center load, improve customer satisfaction, and empower customers to manage their energy usage and costs. (Ambrose, 4T 2357-2363).

The PFD focuses on whether the Company has shown “sufficient” customer interest in the project but provides no indication of what level of interest is “sufficient.” The Company disagrees

with the PFD that it has not presented evidence of “sustained” interest in the project; indeed, the uncontroverted record evidence shows that interest in the project has trended upward over time. (Ambrose, 4T 2360-2361). The Bill Management tool has shown sustained adoption, growing from 310,765 unique users in 2022 to over 1.7 million year-to-date through August 2025, and survey data confirms that 55% of customers are less likely to call the Contact Center after using the tool. Similarly, the BillWise AI pilot engaged 49,000 customers with a 34% repeat usage rate and supported 50 Customer Representative Specialists in handling high-bill calls, providing clear evidence of customer value and operational support (Ambrose, 4T 2361-2362).

Additionally, the PFD fails to consider that the BillWise AI tool is a pilot that only recently concluded on August 1, 2025, that if expanded to the broader customer base will provide much more information. If the Commission accepts the PFD’s recommendation, this new tool’s momentum will be halted before it can grow further and produce more customer benefits. (DTE Electric’s Reply Brief, pp 83-84).

The Company also takes exception to the PFD to the extent it relies on Staff’s argument that DTE Electric did not offer evidence to show that the Bill Management tool and DTE Insight App will become unstable and unreliable if the project is not approved. (PFD, pp 267-268). As detailed in the Company’s Reply Brief, these consequences include (1) the BillWise AI tool will not be released to the Company’s full customer base, which will prevent it from achieving its full potential to help customers understand their bills and manage their energy use, (2) the Bill Management tool will become unstable and unreliable, which will drive customers to call customer service, (3) the DTE Insight App will become unstable and unreliable, and (4) the Energy Bridge tools will lose their licensing and cease to be available for use by customers. Overall, adoption of the PFD’s recommendation would lead to wasted investments and render the tools useless, and any

efficiencies gained and growth from further adoption will be at risk. (DTE Electric's Reply Brief, p 84; Ambrose, 4T 2357-2363).

The Commission should reject the PFD's recommendation and permit full recovery of the costs for the Customer Insight Platform Application Health project as reasonable and prudent.

b. Customer Relationship and Billing Program

The PFD recommends that the Commission adopt Staff's proposed adjustment of \$6.3 million in capital expenditures for the 2026 test year for the Customer Relationship and Billing (CR&B) Program and \$2.7 million in related O&M, finding that the Company did not support the reasonableness and prudence of its proposed expenditures for the project. (PFD, pp 270-271). The PFD concludes that the Company did not persuasively explain the "extreme" increase in costs or "how the project achieves its stated goal of cost management." (PFD, p 271).

The CR&B Program is a fully implemented system that requires regular maintenance, and this project will provide that ongoing support. (Ambrose, 4T 2267-2268). To streamline processes, enhance operational efficiency, improve service delivery, and optimize costs, this project will also include the costs associated with integrating the Automated Application Monitoring Health, Closed Loop COCL Application Health, Customer Information Technology Configuration Management and Customer Legacy Application Health projects into the CR&B program. (Ambrose, 4T 2268).

The Company disagrees with the PFD. The Company fully addressed the reasonableness and prudence of this investment in its Initial Brief. (DTE Electric's Initial Brief, pp 110-112). Further, the PFD would adopt Staff's recommended wholesale adjustment of all proposed expenses related to this Program without challenging any specific calculation or maintenance activities identified as needed to support the CR&B Program.

The PFD also states that in Case No. U-21534, the Company sought recovery for CR&B project maintenance costs of \$1.9 million in capital and \$0.16 million in O&M, which the PFD terms “drastically less than” the request made in this case for \$6.3 million in capital and \$2.7 million in O&M. (PFD, pp 270-271). The PFD notes the Company’s statement in Case No. U-21534 that the project’s costs are “consistent year after year, as it represents fixed-capacity technical teams.” (PFD, p 271). As the Company made clear in its briefs and testimony, this project now includes *four* application health projects (which was not the case in Case No. U-21534) to align with the Company’s strategic vision of cost optimization, and is specifically intended to reduce ongoing maintenance costs by streamlining the Company’s processes, enhancing operational efficiency, and ensuring a more cohesive approach to managing the program. (DTE Electric’s Reply Brief, p 91; Ambrose, 4T 2364). The PFD acknowledges the consolidation but contends that the Company’s project description “is too generalized to persuasively explain the extreme increase in costs or how the project achieves its stated goal of cost management.” (PFD, p 271). On the contrary, Company witness Ambrose explained in his rebuttal testimony that “consolidation of these elements will result in improved service delivery, cost management, and alignment with the Company’s long-term goals.” (Ambrose, 4T 2268). He also explained that the ongoing maintenance activities for this project occur daily, monthly, and annually and reduce the risk of unplanned outages within the CR&B Program that disrupt critical business operations and lead to customer dissatisfaction. (Ambrose, 4T 2363-2367). The Company provided detailed descriptions of specific operational and product support activities, such as Incident Management, Application Health Monitoring, Configuration Management, Release Management, and OS patching, along with clear explanations of the consequences if these processes are not performed, including outages, billing failures, and compliance risks. This level of detail goes far beyond broad

statements and demonstrates the critical nature of these sustainment activities. (Ambrose, 4T 2365-2367). The Commission should reject the PFD's recommendation and permit full recovery of the costs for the CR&B project as reasonable and prudent.

c. DTE Mobile Application Health

The PFD recommends that the Commission adopt Staff's proposed adjustment of \$1.1 million in capital for the DTE Mobile Application Health project for the 2026 test year and \$0.17 million in related O&M. The PFD does not find that the preponderance of the evidence establishes that there is a customer demand for this project, agreeing with Staff that "the App is not a necessity for customers and the proposed additional investment is also not necessary." (PFD, pp 273-274).

The DTE Mobile App Health project is one of two projects that were combined and previously known, in Case No. U-21534, as Customer Digital Channels and Self-Service Program. (Ambrose, 4T 2270). The DTE Mobile App provides customers self-serve options for outage reporting, payments, and bill access, as well as some program management. (Ambrose, 4T 2270).

The Company disagrees with the PFD which does not dispute any individual aspect of the proposed costs for this project but rather makes blanket conclusions based on one data point regarding customer usage and on its failure to recognize the value of the project to the customers who utilize it. The PFD notes the 19% of usage in 2024 and projected increase to 20% for 2025 (PFD, p 273) and appears to conclude that these usage rates do not justify the Company's investment in this program, without explaining why these usage rates are insufficient or what a "sufficient" usage rate would be. The PFD also recounts the Company's evidence that (1) 42% of all outage interactions in 2024 were completed using the DTE Mobile App, (2) in 2024, approximately 30% of customers used the App at least once, (3) on average in 2024, there were 300,000 to 350,000 active users per month, (4) Mobile App interactions have increased by 5% in

the past three years, and (5) in 2023, the Company undertook an investment to rewrite the Mobile App using updated, modern technology resulting in higher completion rates and an increase in digital adoption rates and customer usage. (PFD, pp 272-273). However, the PFD arbitrarily selects only the 19% and 20% figures to support its finding. (PFD, p 273).

The PFD also does not account for additional evidence the Company presented to support the investment. First, when automated interactions such as auto-pay or external electronic fund transfer payments, which do not require customer engagement are removed, the Mobile App accounts for 25% of all self-service interactions. (Ambrose, 4T 2368). Second, since 2015, the Mobile App has been downloaded approximately 2 million times. (Ambrose, 4T 2368-2369). The Company has shown that the costs for the Mobile App should be recovered because the project represents a substantial portion of the Company's customers' outage tool utilization.

The Company also disagrees with the PFD's finding that "the App is not a necessity for customers and the proposed additional investment is also not necessary." (PFD, pp 273-274). While the Mobile App offers the same core functionality as the website, customers prefer different channels, which should be accessible during moments that matter most like during an outage. (Ambrose, 4T 2368-2369). Based on misplaced assertions regarding low usage, the PFD's recommendation, if adopted, would remove a tool that has been available to customers for 14 years, is steadily growing in adoption, and provides a mobile option that customers can utilize without needing to access a website.

Finally, the Company disagrees with the PFD's finding that the proposed additional investment in this project is not needed. (PFD, pp 273-274). As clarified by the Company's briefs and in testimony offered by witness Ambrose, the requested funds are needed to maintain core functionality and security; *i.e.*, they are "essential to keep the app available, secure, and

functional.” (Ambrose, 4T 2369-2371; DTE Electric’s Initial Brief, pp 112-113; DTE Electric’s Reply Brief, pp 85-86). The PFD’s recommendation, if adopted, would prohibit the Company from maintaining this tool and risk the benefits it continues to offer to a substantial portion of customers. The Commission should reject the PFD’s recommendation and permit full recovery of the costs for the DTE Mobile Application Health project as reasonable and prudent.

d. Outage WISMO, PPS and Map Application Health and Outage WISMO, PPS and Map Enhancement

The PFD recommends that the Commission adopt Staff’s proposed adjustment of \$3.0 million in capital for the 2025 bridge period and \$5.25 million (plus \$0.25 million in O&M) for the 2026 test year for the Outage WISMO, PPS, and Map Application Health project and proposed adjustment of \$1.7 million in capital and \$0.525 million in O&M for the 2026 test year for the Outage WISMO, PPS, and Map Enhancement project. (PFD, p 279). The PFD is persuaded by Staff’s position that because approximately \$52 million was approved for the Company’s Error Free Communication (EFC) initiatives in the two previous DTE Electric rate cases, it would be imprudent to allow additional recovery in this proceeding. (PFD, pp 278-279).

The Outage Where Is My Order (WISMO), Premise Power Status (PPS) and Map Application Health project will ensure that the EFC System remains resilient, responsive, and aligned with evolving customer and business needs by conducting sustainment activities to avoid unplanned outages. (Ambrose, 4T 2372-2373). The Outage WISMO, PPS, and Map Enhancement project improves and expands upon the EFC System’s capabilities to continue to elevate the outage communication experience and move the Company further toward long term EFC targets and goals. (Ambrose, 4T 2375-2376, 2300, 2310-2313).

DTE Electric disagrees with the PFD. As addressed in the Company’s Initial Brief, witness Ambrose’s testimony described in detail the need for additional funds for these projects and

showed that the Company has provided evidence that the EFC project is making progress toward its long-term goals. (DTE Electric’s Initial Brief, pp 114-119; Ambrose, 4T 2371-2379). Further, the Commission’s approval of funding in the 2023 and 2024 cases did not proscribe requests for, or approval of, additional funding in future electric rate cases. Rather, the Commission directed the Company to provide in future rate cases “detailed status and expenditures updates on [its] expenditures for the EFC program demonstrating the results of any investments in the program.” (Case No. U-21534 Order dated January 23, 2025, pp 160-161). The Company met this requirement through witness Ambrose’s direct and rebuttal testimonies. (Ambrose, 4T 2302-2316, 2371-2379).

The Commission should reject the PFD’s recommendation and permit full recovery of the costs for the Outage WISMO, PPS and Map Application Health and Enhancement projects as reasonable and prudent.

e. Payment Merchant Fees

The PFD recommends that the Commission adopt Staff’s proposed full disallowance of \$9.998 million of 2025 bridge period capital expenditures for the Payment Merchant Fees project. (PFD, p 284). The PFD finds that the Company did not support the reasonableness and prudence of these costs, particularly the contractor costs, as it “failed to provide a description of the alternatives it considered or any other evidence to corroborate its claim that its long-standing business partners were the most reasonable and prudent contractor choice.” (PFD, pp 283-284).

The Payment Merchant Fees project would utilize a third-party consumer payment provider to process credit and debit card payments for both residential and non-residential customers who choose that form of payment. (Ambrose, 4T 2317-2318, 2382-2383; Foley, 4T 2646-2651).

The Company disagrees with the PFD. The Commission should reject the PFD's proposed full disallowance of the 2025 bridge period costs for the Merchant Payment Fees project and permit recovery of these costs as reasonable and prudent. As discussed in the Company's briefs and testimony, the vendors for this project are long-standing, thoroughly vetted suppliers that are familiar with the Company's payment systems. (DTE Electric's Initial Brief, pp 119-120; Ambrose, 4T 2380). Witness Ambrose explained that the cost for the project includes the design, development, and testing of the payment solution across all payment platforms and the CR&B system, and that the actual costs have been confirmed through executed contracts. (Ambrose, 4T 2381).

At the time of filing, the Company proposed treating residential and non-residential customers differently, consistent with the Commission's January 23, 2025 Order in Case No. U-21534, by directly charging non-residential customers for merchant fees while continuing to recover residential fees through base rates. (Foley, 4T 2675-2676). However, the Company voluntarily withdrew its request for recovery of residential merchant fees through base rates in this proceeding and has chosen to implement a system through which the fees for credit and debit card transactions that were formerly included in rates will now be paid for directly by the customer who chooses to use a credit or debit card. The implementation of the capital project is critical to migrate the payment processor to enable the fee passing feature for our residential customers. While the Commission has ordered the removal of merchant fees from rates, the Company must maintain the ability to offer customers these flexible payment options, and this requires the implementation of the Payment Merchant Fee Project. Disallowing costs associated with this transition effectively requires that the Company absorb merchant fees if they cannot be passed on to those customers who choose to use a credit or debit card to pay their bills. (Ambrose, 4T 2382-2383).

The Company has met its burden of showing reasonableness and prudence of these costs by a preponderance of the evidence and its recovery request should not be denied in light of definitive actual cost information provided through testimony, including rebuttal testimony. The Commission should therefore reject the PFD's recommendation and permit full recovery of the costs for the Payment Merchant Fees project as reasonable and prudent.

f. Corporate Instance Maximo App Upgrade

The PFD recommends that the Commission adopt Staff's proposed adjustment of \$1.4 million in 2026 test year costs for the Corporate Instance Maximo App Upgrade project, finding that the Company did not establish that deferral of the project from 2025 to 2026 supports the request to recover additional amounts, given past projections. (PFD, p 285).

The Company disagrees with the PFD. As discussed in DTE Electric's Reply Brief and witness Ambrose's rebuttal testimony, in Case No. U-21534, the Company projected a need of \$3.749 million for the Corporate Maximo project in 2025, of which only \$3 million was approved by the Commission, resulting in a \$749,000 shortfall. The total request of \$8.160 million reflects both the deferral of the \$3.749 million of previously deferred investment for 2025 plus the projected cost of the investment for 2026. (Ambrose, 4T 2344-2345; DTE Electric's Reply Brief, pp 93-94). Contrary to the PFD's finding that the Company did not support its projected 2026 spend, witness Ambrose also noted in his direct testimony that the Corporate Instance - Maximo Application Suite supports the Work Asset Management function for several key business units at DTE, including Distribution Operations work and asset management. (Ambrose, 4T 2240-2241).

Notably, this project is not a traditional software update; it requires a complete re-platforming of Maximo. Thus, the Company would be operating on an unsupported platform without this investment, jeopardizing system resiliency, security, and reliability. Deferring or

disallowing these costs would significantly increase operational risk and compromise the Company's ability to manage critical work and asset functions. (Ambrose, 4T 2240-2241). The PFD's conclusion that the Company did not justify its 2026 spend neglects the project's documented scope expansion and evidentiary support thereof. (Ambrose, 4T 2248, 2344-2345) For these reasons, the Commission should reject the PFD's recommendation and approve full recovery of the requested costs as reasonable and prudent.

g. Maximo Engineering Process Automation

The PFD recommends that the Commission adopt Staff's recommended disallowance of \$2.55 million for the Maximo Engineering Process Automation project in 2024, finding that the Company "has not demonstrated this investment provides benefit to customers or is otherwise reasonable and prudent." (PFD, p 288). Specifically, the PFD found that the Company "did not establish that accelerating the implementation of the project by one year was reasonable and prudent" and that the Company "has not provided evidence to support its stated reason for the decision (i.e. cost savings)" and that "it appears that earlier implementation in fact cost more." (PFD, pp 287-288).

DTE Electric disagrees with the PFD. As detailed in Company witness Ambrose's rebuttal testimony, this project supports DTE Electric's nuclear safety objectives by modernizing engineering and work management systems as Fermi 2 transitions to electronic work packages and disallowing the investment would inappropriately discount these strategic benefits. (Ambrose, 4T 2349). As noted in the Company's Initial Brief, witness Ambrose explained that the cost savings benefit of the project is the reduction in total project costs associated with combining this project with the I2R project. (DTE Electric's Initial Brief, pp 103-104; Ambrose, 4T 2348-2349). Advancing the project by one year and combining it with the I2R project was a strategic decision,

reducing overall project costs and avoiding duplicative work (Ambrose, 4T 2250-2251). Contrary to the PFD's finding, the term "cost savings" in the Company's testimony referred to the reduction in total project costs achieved through this integration, not annual operational savings.

Additionally, the project will streamline the engineering and work management systems at Fermi by reducing manual tasks, improving reporting capabilities, and reducing technical complexity of managing multiple system interfaces. (Ambrose, 4T 2250). The Company's decision to advance the project to combine it with the I2R project was reasonable and prudent to achieve overall project cost savings and these costs should be permitted to be recovered. The Commission should reject the PFD's recommendation and permit full recovery of the costs for the Maximo Engineering Process Automation project as reasonable and prudent.

h. Backup Environmental Growth

The PFD recommends that the Commission adopt Staff's proposed adjustment of 20% of the requested costs for the Backup Environmental Growth project in 2025 and 2026, equaling \$100,000 in each year. The PFD relies on Staff's argument that the Company spent only 80% of its projected costs on this project in the past three years and a 20% reduction is reasonable and prudent in light of the Company's history of over-projecting this expenditure. (PFD, p 289).

DTE Electric disagrees with the PFD. The Backup Environmental Growth project ensures that IT devices that manage DTE Electric data have sufficient capacity for backup creation and secure storage. (Ambrose, 4T 2161). Contrary to the PFD's conclusion, the Company provided detailed evidence supporting the 2025 and 2026 spend requests. The 2025 target was prudently adjusted to \$0.5 million, with \$0.357 million already committed for software, hardware, and infrastructure upgrades, and the remaining funds allocated for migration activities. In 2026, the

full requested amount will complete critical phases, including transitioning to Power Protect Data Manager to strengthen data security and backup resilience. (Ambrose, 4T 2350-2351).

The PFD's recommendation does not properly acknowledge this evidence or more generally the ebb and flow of project execution as evidenced by the Company's allocation of costs between labor and non-labor components, covering project management, technical labor, software and hardware costs, and essential migration activities. (Ambrose, 4T 2350-2351). The Commission should reject the PFD's recommendation and permit full recovery of the costs for the Backup Environmental Growth project as reasonable and prudent.

i. Network Hardening and Operations

The PFD recommends that the Commission adopt Staff's proposed adjustment of \$0.5 million for 2026 for the Network Hardening and Operations project, agreeing with Staff that evidence of additional project costs for 2026 provided in rebuttal testimony came too late in the proceeding to allow for proper review. (PFD, p 291).

The Network Hardening and Operations project supports the Network Engineering services the Company uses to deploy capital assets purchased under the Network End of Life (EOL) program. This "year-over-year project" uses a third-party service provider to assess the Company's networks and implement operational system upgrades to fulfill the hardening requirements of network infrastructure. (Ambrose, 4T 2165-2166). The 2026 project scope is substantially expanded to include additional enhancements at three critical sites supporting Fermi 2. (DTE Electric's Initial Brief p 105; Ambrose, 4T 2352-2353).

DTE Electric disagrees with the PFD. Disallowance of these important project funds is not justified in light of the Company's detailed explanation of the need for the expanded project scope. The record demonstrates with sufficient specificity that increases in these costs result from essential

investments in redundancy and security, which are necessary to minimize downtime and operational risks for the expanded scope of the Fermi 2 sites. (Ambrose, 4T 2351-2353). These activities collectively address the increasing need for network stability and resilience by mitigating single points of failure and supporting essential infrastructure for critical communications. The assumption that the scope remained unchanged was fully rebutted with precise descriptions of additional work, including LAN redundancy, failover protocols, and hardware upgrades necessary to mitigate single points of failure and support regulatory compliance (Ambrose, 4T 2351-2353). Furthermore, it is also procedurally inappropriate to summarily conclude that rebuttal evidence is “too late.” (See generally MCL 24.272(4) of the Michigan Administrative Procedures Act “*A party may submit rebuttal evidence.*”; R 792.10427 of the Rules of Practice and Procedure Before the Commission “*A party shall have the right of cross-examination and shall have the right to submit rebuttal evidence.*”) Additionally, the Commission can rely upon any evidence of record in arriving at its decision. Therefore, the Commission should reject the PFD’s recommendation and permit full recovery of the costs for the Network Hardening and Operations project as reasonable and prudent.

j. Digital Worker Experience Electric End-of-Life

The PFD recommends that the Commission adopt Staff's modified proposal to disallow labor costs for the Digital Worker Experience Electric End-of-Life (EOL) project for 2024 that exceed such costs approved in Case No. U-21534 and otherwise approve the requested costs for this project. (PFD, pp 293-294).

This project is an "annual investment" to replace EOL endpoint devices such as laptops, desktops, tablets, and smart devices that degrade after five years but are used by DTE employees to access DTE systems, communications, and data. (Ambrose, 4T 2171).

The Company disagrees with the PFD with respect to its recommendation to disallow a portion of labor costs for this project. As discussed in the Company's Reply Brief, Staff's Initial Brief agreed that labor costs should be accounted for and revised its calculations to include the Company's full projected labor cost in 2023 and 2025, but asserted that the Company included \$1.597 million more in labor costs for 2024 than was approved in Case No. U-21534 without evidence for its use, and continued to recommend disallowance of these "excess labor costs." (Staff Initial Brief, p 110). The Company provided detailed information regarding these costs, including a breakdown of the cost of each device. (Ambrose, 4T 2340-2342). Further, Company witness Ambrose explained the variance for the 36 months ending December 31, 2025, due in part to the 10% and 20% disallowances directed by the Case No. U-21534 order and an additional \$2.1 million for additional field worker devices for supplemental staff supporting storm restoration efforts and the DTE student program. (Ambrose, 4T 2172).

Any disallowance now disregards the evidence that the variance reflects additional scope for field worker devices supporting storm restoration and the DTE student program, as well as necessary configuration, deployment, and testing activities. These labor costs are essential for the

operational readiness of the devices purchased under this project. The expanded scope and operational needs are fully documented in the record. (Ambrose, 4T 2171-2173, 2339-2344). (Ambrose, 4T 2171-2173) The Commission should reject the PFD’s recommendation, which lacks sound rationale, and approve full recovery of the costs for the Digital Worker Experience Electric EOL project as reasonable and prudent.

k. Field Worker Device End of Life

The PFD recommends that the Commission adopt Staff’s proposed adjustment of \$135,000 in the 2026 test year for the Field Worker Device EOL project, finding that the Company did not support the reasonableness and prudence of its cost projections. The PFD agrees with Staff that “it is reasonable for the costs of the project to decrease because the number of devices being replaced is decreasing each year,” and notes that the Company did not “disclose” that it expects labor and material costs for 2025 and 2026 to increase by a significant percentage until the rebuttal stage of this proceeding. The PFD also agreed with Staff that the Company’s projected cost increase is “arbitrary” and that the Company did not “sufficiently justify recovery of the full amount it seeks.” (PFD, pp 295-296)

This project represents the annual replacement of enterprise Mobile Data Terminal (MDT) devices, which are the computerized devices used on mobile devices to communicate with the centralized control system. The MDTs provide maps, geographic locations, and other information to field workers and customer service representatives and the current fleet of MDTs are experiencing multiple device and connectivity failures. (Ambrose, 4T 2175).

The Company disagrees with the PFD. The lifecycle of the current MDT fleet has been stretched to the point that field crews are experiencing multiple device and connectivity failures. This impacts the field crews’ ability to gain insight into customer issues and outages, provide

updates to leadership and customer service, and communicate resolution and closure of customer concerns in a safe and efficient way. (Ambrose, 4T 2175).

Further, the Company's briefs and witness Ambrose's testimony show that the projected cost increase is well supported and not arbitrary. The Company's cost projections reflect anticipated increases in labor and equipment expenses over time. Staff applied per-unit costs only for 2024 and used fixed costs for equipment in 2025 and 2026. However, the Company's cost projections reflect anticipated increases in labor and equipment expenses over time, which Staff's calculations overlook. (Ambrose, 4T 2339-2344). In contrast to Staff's simplified calculation, the Company's cost projections for equipment replacement reflect a comprehensive approach that includes not only the price of the devices but also associated costs such as labor for configuration, deployment, testing, and integration. These projections factor in changes in market prices, expected usage, and operational complexities over time. Unlike a simple per-unit cost calculation, replacement costs consider fixed and variable components, ongoing maintenance, and the realistic operational lifecycle of the assets. This ensures that the budgeted costs are prudent, accurate, and reflective of actual expected expenditure rather than arbitrary averages. (DTE Electric's Initial Brief, pp 105-106; Ambrose, 4T 2346-2347).

The Company also takes exception to the PFD's characterization of the Company's testimony as "self-serving." (PFD, p 296). This is an inaccurate characterization of the Company's proper rebuttal testimony. The Company renews its objection to the procedurally inappropriate conclusion that rebuttal evidence is "too late." (MCL 24.272(4); R 792.10427). The Commission can rely upon any evidence of record in arriving at its decision.

The Company has met its burden of showing reasonableness and prudence of these costs by a preponderance of the evidence and its recovery request should not be denied in light of

definitive actual cost information provided through testimony, including rebuttal testimony. The Commission should therefore reject the PFD's recommendation and permit full recovery of the costs for the Field Worker Device EOL project.

I. Distribution Operations Productivity Center

The PFD recommends that the Commission adopt Staff's proposed disallowance of \$439,999 for the 2024 bridge period for the Distribution Operations (DO) Productivity Center. (PFD, p 298-299).

The Company takes exception to the PFD's recommendation. The DO Productivity Center project will equip field crews with a Situational Awareness Dashboard that centralizes real-time data, identifies operational inefficiencies, and supports standardized process improvements, leading to faster restoration times, reduced rework, and enhanced safety. It is a prudent and essential investment that enhances operational efficiency, safety, and reliability, directly benefiting customers. (Ambrose, 4T 2354-2355).

While the PFD observes that the Project Prioritization Score is low, this rating alone should not be used to determine whether a project merits funding. The score is designed to help the Company categorize and compare initiatives—not to exclude them. It provides a framework for aligning investment dollars with strategic drivers and organizational goals across a broad portfolio. A lower score simply indicates that the project may align differently with certain criteria, not that it lacks value, impact, or necessity. Therefore, funding decisions should consider the project's full strategic, operational, and compliance-driven importance rather than relying solely on its prioritization score. The Commission should therefore reject the PFD's recommendation and permit full recovery of the costs for the DO Productivity Center project. (Ambrose, 4T 2125-2129)

m. Information Protection Security

The PFD recommends that the Commission adopt Staff's proposed adjustments of \$186,000 in 2025 and \$184,000 in 2026 for capital expenditures and \$283,000 in 2025 bridge period O&M for the Communication Compliance and Data Loss Prevention (DLP) Diversification project. The PFD agrees with Staff that the Company failed to provide sufficient information in its audit responses to permit recovery of these costs at this time. (PFD, p 302). The PFD notes that the Company did not "raise[] operational necessity, risk exposure, and the potential penalties for non-compliance across external platforms" as justifications for the project until rebuttal testimony. (PFD, p 302). The Company renews its objection to the procedurally inappropriate conclusion that rebuttal evidence is "too late." (MCL 24.272(4); R 792.10427). The Commission can rely upon any evidence of record in arriving at its decision. The PFD is also persuaded by "Staff's concerns that despite an 'operational environment that has advanced rapidly over the last 12 to 18 months' DTE waited until 2025 to begin this expansion to external applications and platform, despite the alarm bells raised in Mr. Ambrose's rebuttal." (PFD, p 303).

DTE Electric disagrees with the PFD. The assertion that the Company "waited until 2025" to begin expansion mischaracterizes the timing and nature of this project. The Communication Compliance and DLP Diversification project will configure tools such as Communication Compliance and Data Loss Prevention and deploy them across all corporate channels of communication as part of the Company's platform strategy to migrate security functions to its Microsoft platform to aid in monitoring and securing employee communications and ensure compliance standards are met. (Ambrose, 4T 2145-2146).

Furthermore, as shown by the Company's briefing and testimony, the Company's operational environment has advanced rapidly over the last 12-18 months, and the Company's

current security barriers do not fully address this new landscape. To uphold the Company's security posture and protect its operational environment, it is essential to implement Microsoft Communication Compliance and Data Loss Prevention across all platforms to prevent sensitive data exposure and ensure regulatory compliance. (DTE Electric's Initial Brief p 107; Ambrose, 4T 2355-2357). Regarding compliance and the lack of issues to date, the Company is seeking these funds to expand this program to ensure that it continues to protect its operational environment; requiring evidence of a violation or other problem before approving recovery applies an unreasonable and not useful standard to the cost recovery request. (DTE Electric's Reply Brief, pp 94-95).

The Commission should reject the PFD's recommendation because the Company has demonstrated, by a preponderance of the evidence, that this investment is both reasonable and necessary to protect its operational environment and maintain compliance in a rapidly evolving risk landscape. The timing of this project reflects prudent planning and proactive risk mitigation, not delay, and requiring evidence of a violation before approving recovery imposes an unreasonable and counterproductive standard.

2. Projects with Level 2 and Level 3 Cost Estimates

The PFD recommends that the Commission adopt Staff's proposal of an adjustment of 20% of costs for five of the eight IT projects with Level 2 cost estimates in this case, resulting in an adjustment of \$0.685 million in the 2026 test year and \$16,000 in O&M. The PFD finds that the Company did not offer evidence to disprove the cost variances identified by Staff. The PFD "recognizes that project cost estimates are temporary by nature and must start somewhere," but concludes that "costs cannot be properly evaluated by the Commission for inclusion in rates at the Level 2 cost estimate phase." (PFD, pp 306-307). The PFD finds that no evidence contradicted

Staff's rationale for using the Association for the Advancement of Cost Engineering (AACE) Class 3 Estimate to derive its 20% disallowance. (PFD, p 307).

The PFD also recommends that the Commission adopt Staff's proposed adjustment of 10% for Level 3 cost estimates for IT projects, resulting in a reduction of \$13.077 million in capital expenditures in 2025 and \$11.367 million in the 2026 test year. As with Level 2 cost estimates, the PFD "recognizes that project cost estimates are temporary in nature and project changes may occur over time," but "is not convinced ... that the Commission should rely on the Level 3 cost estimates for ratemaking purposes when this record shows that the Company greatly over- or under-estimates the costs of most of the projects at the Level 3 estimate phase in the last rate case even when it made its best effort to create an accurate Level 3 cost estimate at 'the point of development.'" (PFD, pp 311-312). The PFD concludes that "[c]onsistent with [the] Commission's decision in Case No. U-21534 ... this PFD recommends the Commission find it 'unfair to pass costs onto ratepayers without the assurance that its entirety will be used for the intended reasonable and prudent investment.'" (PFD, pp 311-312).

DTE Electric disagrees with the PFD. First, the Company's briefing and testimony has explained that cost variances are an expected and normal aspect of capital project execution. (DTE Electric's Reply Brief, pp 79-81; DTE Electric's Initial Brief, pp 97-99; Ambrose, 4T 2332-2333; Robertson, 4T 2086-2093). The PFD acknowledges that project cost estimates are "temporary by nature and must start somewhere," yet applies an arbitrary disallowance that disregards the Company's refined estimation process and lifecycle controls. Variances cited by the PFD reflect legitimate scope and schedule adjustments inherent to project execution, not deficiencies in estimating practices. The Commission should reject this recommendation and approve full recovery.

Further, the PFD, like Staff, fails to account for the refinements to the Company's IT capital investment planning process, specifically its revised IT project estimation requirements that have been made since the 2024 rate case. (Ambrose, 4T 2126-2128). This conclusion mischaracterizes the nature of Level 3 estimates and disregards record evidence that these estimates are accurate and comprehensive at their point of development, supporting budget decisions. (Ambrose, 4T 2335). Variances between Level 3 estimates and final costs occur due to legitimate scope changes and lifecycle refinements, which are standard in project management and anticipated in mature estimating practices. The PFD's reliance on historical annual variances rather than full lifecycle performance incorrectly evaluates estimation accuracy. The Commission should reject this recommendation and approve full recovery. (Ambrose, 4T 2335).

Moreover, contrary to the PFD's statement that no evidence contradicted Staff's rationale for using the AACE Class 3 Estimate to derive its 20% disallowance, Company witness Robertson offered un rebutted evidence with regard to the lack of usefulness and appropriateness of applying the AACE system overall to utility project estimates that the PFD does not consider.

First, Staff's application of AACE accuracy ranges to the Company's cost estimates was inappropriate, because Staff did not consider that the amount for appropriate contingency is not included, and as a result, the "estimates are already skewed towards the lower end of any accuracy range that might attempt to determine the range of actual project cost." (Robertson, 4T 2086). Relatedly, Staff applied the AACE accuracy range to estimates that exclude contingency and limited its allowance to the lower bound of the range, which effectively results in an allowance of costs less than the lower bound of the range, as depicted in Figure 3 of witness Robertson's testimony. (DTE Electric's Initial Brief p 99; Robertson, 4T 2090-2093).

Second, witness Robertson explained that in order to determine the project-specific risk

and expected accuracy of estimates, a risk analysis must be performed. Many utility projects, including IT projects, are routine and repetitive, located in familiar locations, and reliant on established supply chains; even projects that include complex or relatively novel technologies are rarely without precedent in the industry; “[d]irectionally, utility projects, such as those included in this proceeding, are subject to lower systemic risks.” (Robertson, 4T 2086-2087). As a result, applying standardized confidence ranges to the Company’s IT project cost estimates without accounting for the specific scope and nature of the risks attendant to those projects is inappropriate.

The PFD applies arbitrary disallowances to Level 2 and Level 3 estimates that disregard the Company’s evidence and expert review. Cost estimates are inherently iterative, and observed variances reflect prudent scope adjustments not estimation failure. Hence, adopting the PFD’s recommendations would penalize responsible planning.

The Commission should reject the PFD’s recommended disallowance of 20% of the cost of IT projects with Level 2 cost estimates and 10% of the cost of IT projects with Level 3 cost estimates and approve the Company’s full request for recovery of these IT capital investments.

3. Projected Overhead & Other Costs (Capital)

The PFD recommends that the Commission adopt Staff’s proposed disallowances of \$0.731 million in 2023, \$0.284 million in 2024, and \$2.297 million in 2025²⁷, and adjustment of \$11.542 million in the 2026 test year associated with projected overhead and other capital costs for IT projects not already approved in Case No. U-21534 and for which Staff does not already recommend a full or partial adjustment. (PFD, p 315). The PFD finds that the Company failed to

²⁷ The amount included in Staff’s Initial Brief is \$2.947 million for 2025 (as opposed to the incorrect amount of \$2.297 million referenced in the PFD), as stated on page 81 of the Staff Initial Brief. This amount is correctly reflected in both Staff’s and DTE Electric’s Revenue Requirement calculation in Staff’s workpapers and Attachment A to this document, respectively.

justify the reasonableness and prudence of these costs, stating that DTE Electric did not provide a method for applying these costs to future projects or sufficient detail regarding how it calculated the requested costs for existing projects. The PFD also finds no evidence in the record that the Commission previously approved overhead costs such as those requested by the Company. (PFD, p 314-315).

DTE Electric disagrees with the PFD's conclusion that the Company failed to justify the reasonableness and prudence of the overhead costs. The PFD's recommendation and findings regarding a method for applying these costs to future projects and sufficient detail regarding how the Company calculated the requested costs for existing projects repeats the contradiction that Company witness Uzenski identified in Staff's testimony, specifically: recognizing that overhead costs cannot be traced to a specific asset but still expecting specific cost information for individual IT projects. (DTE Electric's Reply Brief, pp 81-82; DTE Electric's Initial Brief, pp 99-101; Uzenski, 4T 2501). The overhead costs are expenses of a business that are not directly related to constructing an asset or providing a service. They are recurring, indirect costs. Overheads are one component of an asset and by definition, the application of overheads to a project cannot be described in terms of a specific function or impact (Uzenski, 4T 2499). However, the Company did provide examples to Staff of the types of expenses that are included in overhead and these are represented in Staff Exhibit S-12.9 (Uzenski, 4T 2500). They include costs, for example, such as AFUDC, banking and financing fees, mileage and commuting fees, miscellaneous materials from inventory, dues and assessments, utilities, investment recovery from scrap sales, lease and rent expense, meal allowances, office supplies, permits and licenses, postage, telecommunications, travel, and vehicles expenses. These are all necessary expenses to operate the Company and are not generated by particular projects.

The PFD also notes but fails to account for Company witness Uzenski's testimony that the USoA requires capitalization of overhead costs. (Uzenski, 4T 2500). Further, the PFD acknowledges but does not give appropriate weight to witness Uzenski's testimony regarding the well-accepted treatment for overhead costs, to accumulate them in total and allocate them to capital projects by applying an overhead rate to construction charges. (Uzenski, 4T 2500). With no change in accounting policy or underlying conditions, the proposed disallowance is inconsistent with established USoA standards and practice and the record.

For the foregoing reasons, the Commission should reject the PFD's proposed disallowance of overhead costs for the Company's IT capital projects and permit full recovery of these traditional components of such projects.

H. Corporate Staff Group

1. Facilities

a. Headquarters Plaza

The PFD adopts the position of AG witness Coppola and recommends the Commission disallow planned capital expenditures in the amount of \$4,001,000 for 2025 and \$3,754,000 for 2026 (\$7.8 million total) for renovations to the Company's headquarters building. (PFD, p 317). DTE Electric takes exception to this recommendation as unfounded. Neither the AG nor the PFD provide a compelling explanation of why "DTE has not presented enough evidence" and instead seek to exclude these reasonable and prudent planned capital expenditures forecasted to be incurred in 2025 and 2026 because they "may be recovered in a future rate case[.]" But Company witness Uzenski has presented uncontroverted and substantial evidence that the Company has initiated design work for the plaza renovation project with solicitation of bids scheduled for the

work in Q4 of 2025. (Uzenski, 4T 2498-99). Witness Uzenski also detailed the project scope to include updating the building's pipes and plumbing, which are original to the plaza space connecting the buildings within the headquarters complex and built in 1972, as well as renovating the first and second floors of the plaza space (under the current cafeteria and meeting area) to bring the Company's headquarters into compliance with current city and state building codes. (Uzenski, 4T 2499). The Company explains in its briefing that the plaza renovation will occur in 2025 and 2026, as planned, and is necessary and prudent to complete, including to bring its headquarters building into compliance with the current building code. (DTE Electric's Reply Brief, p 105). Accordingly, the Company's request for \$7.8 million to complete this needed project should be approved.

2. Other Corporate Projects and Adjustments

The PFD recommends the Commission remove the forecasted capital expenditures for other corporate projects in the amount of \$4,388,000 for 2025 and \$4,567,000 for 2026. The Company takes exception to this proposed adjustment as the Company explained that these items are related to emergent work. (Exhibit AG-17, p 8). The Company requests that the Commission approve the expenses which are reasonable and prudent to address emergent situations (DTE Electric Reply Briefs, pp. 105-106).

I. Transportation Electrification Plan

DTE Electric witness Foley presents the Company's proposals to continue Transportation Electrification Plan (TEP) execution. (Exhibit A-29, Schedule S1; Foley, 4T 2616-2646; DTE Electric's Initial Brief, pp 206-216; DTE Electric's Reply Brief, pp 196-199). The PFD recommended the Commission approve many components of DTE Electric's TEP without

modification. However, the PFD also recommends a series of actions with which the Company respectfully disagrees.

1. Rebate Program Extension and Subprogram Funding Reallocation

The Company requested authorization to treat up to \$128.3 million as a regulatory asset between 2025 and 2028 in support of its TEP rebate programs, and record rebates as a regulatory asset through 2028. (DTE Electric’s Initial Brief, pp 210-213). DTE Electric also sought confirmation that it could reallocate TEP funding between rebate programs based on prevailing market trends to maximize support of EV adoption. (DTE Electric’s Initial Brief, p 211-213; DTE Electric’s Reply Brief, p 198). The PFD separately addresses these two requests.

First, the PFD agrees with the Company’s proposal to extend regulatory asset treatment until the end of the current TEP in 2028. (PFD, p 342). As to the second request, the PFD recommends that the Company be permitted to shift \$4.39 million from the non-DAC/non-rural on-route DCFC program to the public L2 program between 2025 and 2028. (PFD, p 342). The PFD further declines to support allowing DTE Electric to unilaterally reallocate funding between rebate programs, and, instead, requests that DTE Electric present a “comprehensive proposal from DTE for what standards would be employed regarding fund reallocation, and how the Company would report such fund reallocation to permit Commission oversight.” (PFD, p 343). While the Company appreciates the PFD’s recommendation on the first point and second part related to shifting of \$4.39 million from the non-DAC/non-rural on-route DCFC program to the public L2 program, it reiterates its proposal in its prior briefing and respectfully requests that Staff be responsible for providing any guidelines and reporting requirements on the Company’s ability to shift funding between programs. (DTE Electric’s Initial Brief, p 213). The Company agrees to work with Staff to establish guidelines and reaffirms its prior comments in its Reply Brief that

Staff should consult other interested stakeholders when establishing reallocation guidelines, as appropriate. (DTE Electric’s Reply Brief, p 198).

2. Benefit Cost Analysis of Transportation Electrification Plan

The PFD recommends acceptance of the existing BCA used by the Company for its TEP. (PFD, p 347). The PFD also recommends es that the Company “use the BCA collaborative tool in *the rate case* following when it becomes available, which DTE already anticipates doing” (PFD, p 347) (emphasis added). To clarify, the Company agreed, both in direct testimony and rebuttal, to use the BCA collaborative tool once it becomes available *in its next TEP, not its next rate case*. (Foley, 4T 2669-2670). Likewise, NRDC and Sierra Club witness Woolley recommended that the Company use the BCA collaborative tool in a future TEP (when available). (Wolley, 5T 4796-4798, 4817). Ensuring the record accurately reflects these aligned positions is essential so that the Commission does not inadvertently impose a requirement that no party supported and that the Company did not agree to. Accordingly, the Company requests that the Commission clarify this point and adopt the Company’s stated commitment: that DTE Electric will implement the BCA collaborative tool in its next TEP, once the tool is available.

J. Accumulated Provision for Depreciation

The PFD notes that the differences between the Company’s, the AG’s, and Staff’s balance for the accumulated provision for depreciation results from differences in net plant projections. Based on the PFD’s proposed net plant projections, the PFD proposes a \$26.6 million downward adjustment to the Company’s proposed depreciation reserve, resulting in a projection of \$6.895 billion for the PFD’s proposed depreciation reserve. (PFD, p 352; Appendix B to PFD).

The Company takes exception to this proposed adjustment for all of the reasons it opposes the PFD’s adjustment to net plant expenses as discussed above. The Company accordingly

maintains that the Commission should approve a depreciation reserve of \$6.921 billion consistent with the Company's projection in its Reply Brief. (DTE Electric's Reply Brief, Attachment A, page 2, line 7).

K. Working Capital

The PFD identifies the Company's projected working capital amount of \$1.375 billion as shown in Exhibit A-12, Schedule B1 and discusses three adjustments proposed by Staff and the AG and agreed to by the Company to adjust working capital. (PFD, p 353). After these adjustments, DTE Electric proposed an allowance for working capital in the amount of \$1.365 billion as presented in its Reply Brief, Attachment A, page 2, line 20. The Company takes no exception with the PFD as it finds that the Company's calculation of working capital, which is consistent with GAAP and prior rate case calculations, should be accepted. Notably, the PFD rejects the AG's recommendation for an increase of \$100 million to shift PTMM costs from capital expenditures to a regulatory asset so no adjustment to working capital is appropriate. (PFD, p 355).

L. Rate Base Summary

The Company maintains that based on the acceptance of the adjustments identified in its Initial Brief and Reply Brief, DTE Electric supports a \$23.515 billion net balance as shown on Attachment A, page 2.

VI. COST OF CAPITAL

The PFD recommends a weighted, after-tax overall rate of return of 5.64%. (PFD, p 370 and Appendix D to PFD). The PFD's recommendation reflects a capital structure of 50% debt and 50% equity, along with a long-term debt cost rate of 4.27%, a short-term debt cost rate of 3.85%, and a return on equity of 9.90%. (PFD, p 370 and Appendix D to PFD). DTE Electric disagrees

with the PFD's recommendation and requests a weighted, after-tax overall rate return of 6.03% (Vangilder, 3T 1588; Exhibit A-14, Schedule D1, line 10, column (g)), which the Commission should adopt for the reasons discussed below.

A. Capital Structure

As supported by DTE Electric's Initial and Reply Briefs and the testimony of witnesses Lepczyk, Nelson, and Sheilendranath, DTE Electric presented a 50.75% equity and 49.25% debt capital structure for the 2026 test year. (DTE Electric's Reply Brief, pp 106-111; DTE Electric's Initial Brief, pp 122-125). The PFD concludes that DTE Electric did not "present[] a persuasive case for increasing the equity amount in [its] capital structure" from 50.0%. (PFD, p 362). The PFD relies on the Commission's recent determinations that "a balanced capital structure is reasonable and appropriate for both DTE and Consumers." (PFD, p 362). The PFD states that "DTE's significant capital investment program is not new, and the Company has had no difficulty in raising debt capital at favorable rates with a balanced capital structure." (PFD, p 362). Finally, the PFD references the AG witness Coppola's testimony that "the actual capital structure for DTE Electric, to some degree, is determined by its parent company, which may elect to infuse equity capital at any time," which assertion the PFD stated "is not addressed by either NARUC or in Mr. Bonbright's work, as quoted by Ms. Nelson." (PFD, p 362).

DTE Electric disagrees with the PFD. As discussed in its Reply Brief, (DTE Electric's Reply Brief, p 108), the Company acknowledges the Commission's recent decisions approving a "balanced" 50/50 capital structure, including in Case No. U-21534, and its own election since Case No. U-20561 not to propose a different capital structure in order to reduce the scope of contested issues in those cases. The Company recognizes the balance between investor and customer interests that the Commission must consider under the *Hope* and *Bluefield* standards with these

determinations and also notes the Commission’s acknowledgement that this balancing of regulatory interests is not set in stone. As MNSC notes, the Commission’s most recent discussion of capital structure was in the Consumers’ Energy Order issued March 21, 2025, in Case No. U-21585. In that Order, the Commission stated that “there is some degree of flexibility” to its evaluation of capital structure. (Case No. U-21585 Order dated March 21, 2025, p 232). The Commission also agreed with the ALJ in that proceeding that “the aspirational goals expressed in previous Commission orders are not permanently binding and that any target for the Company’s capital structure should change if evolving circumstances indicate that the target is no longer a sound policy.” (Case No. U-21585 Order dated March 21, 2025, p 232). Similarly, in the Company’s 2023 electric rate case, Case No. U-21297, the Commission stated that “the appropriate capital structure is not static and should reflect market conditions and opportunities.” (Case No. U-21297 Order dated December 1, 2023, p 177).

DTE Electric disagrees with the PFD’s retrospective rationale that the Company’s capital investment plans are not new and that “the Company has had no difficulty in raising debt capital at favorable rates with a balanced capital structure.” (PFD, p 362). As supported by the Commission decisions addressed above and as discussed in the Company’s Reply Brief, pp 108-109, the utility’s capital structure is not static and should adjust when circumstances change. This case is not the first one in which the Company has seen “evolving circumstances” that justify an adjustment to the capital structure target; it is simply the first case in which the Company has determined to pursue that adjustment. With this case, as discussed in DTE Electric’s Initial Brief, p 125, considering the magnitude of the capital expenditures that the Company needs to make in the coming years, combined with the interest in maintaining a ratemaking capital structure

consistent with its actual capital structure, a capital structure of 49.25% debt and 50.75% equity is reasonable and appropriate and should be approved.

Additionally, the Company's ability to raise debt capital at favorable rates in the past should not dictate an appropriate debt/equity structure for the 2026 test year. The PFD did not acknowledge or discuss the rebuttal testimony of witness Sheilendranath that while DTE Electric currently has strong credit ratings, credit metrics can be negatively impacted by an expected reduction in future cash flows. Rating agencies closely monitor cash flow metrics in determining utility bond ratings. Reductions in the cash flow metrics, such as cash flow to debt ratios (i.e., FFO to debt ratio) could negatively impact the Company's credit profile. If future cash flows carry greater risk, the Company's FFO to debt metric decreases, potentially risking credit rating downgrade. Increasing allowed ROE or adjusting the capital structure to comprise more equity would become necessary to offset adverse impact to the Company's credit quality. (Sheilendranath, 3T 1056-1058). While S&P currently has a stable outlook for DTE Electric, this outlook reflects the assumption that the Company will generate sufficient cash flows to maintain financial measures that support S&P Global Ratings-adjusted FFO to debt. (Sheilendranath, 3T 1056-1058).

Witness Nelson added, and the PFD did not address, that regulatory risk affects not only the Company's credit ratings but also the required return expected by equity investors. The Company's investment grade credit ratings and its current cash flow metrics indicate that the Company is financially stable. However, credit ratings are not a complete measure of the risk of a company's equity, i.e., they do not assess the systematic and non-diversifiable risk of the Company's equity. Instead, their current ratings only imply that rating agencies assign a low probability that the Company would default on its debt, given its current cash flow metrics. Because equity investors have a subordinate claim on earnings after debt holders, they are

concerned with risk factors beyond those that affect debt investors. (Nelson, 4T 3114). Irrespective of the Company's investment grade credit rating, equity investors will expect a return commensurate with DTE Electric's total risk profile, including business risk, systematic and non-diversifiable risk, and financial risk. (Sheilendranath, 3T 1058-1059).

Further, the PFD's reliance on AG witness Coppola's testimony regarding DTE Electric's parent company (PFD, p 362) does not appear to fully account for DTE Electric witness Nelson's rebuttal testimony, in which she testified that comparisons to the holding company level are not the correct measure of an appropriate capital structure for a regulated electric utility. (Nelson, 4T 3121-3122). Witness Nelson explained further:

Consolidated holding companies do not have an obligation to serve and are, therefore, financed differently than their regulated operating subsidiaries. Unlike the parent company, regulated operating subsidiaries must maintain financial flexibility to meet the obligation to serve in all operating and market environments. That financial flexibility has a cost. Capital at the holding company level finances a variety of business segments (both regulated and unregulated) each with different risk profiles and return requirements. For these reasons, the proper comparison of the Company's capital structure is to the capital structures that finance the proxy companies' *regulated* electric operations.

(Nelson, 4T 3121-3122).

Based on the foregoing, the Commission should reject the PFD's recommendation and approve DTE Electric's proposed capital structure of 50.75% equity and 49.25% debt.

B. Cost Rates

1. Long-Term Debt Cost Rate

The PFD recommends that the Commission adopt Staff's proposed long-term debt cost rate of 4.27%. The PFD states that this rate "benefits from updated information and projections, and it utilizes a spread derived from the average of the Company's last year of spread quotes from Scotiabank." (PFD, p 364).

DTE Electric disagrees with the PFD. The Company's recommended long-term debt cost rate of 4.29% was based on an issuance rate of 5.78% for 2026 based on an average projected 30-year Treasury rate of 4.59% plus a 119 bps spread, which when applied to actual 2025 issuances results in 4.29%. This accounts for updated weighted average long-term debt cost as of December 31, 2026, as presented in Company witness Lepczyk's rebuttal testimony. (Lepczyk, 4T 2928, Exhibit A-45, Sch. KK1). Further, as the PFD notes, the AG accepted both DTE Electric's initially recommended 4.24% rate and the updated 4.29% rate. (PFD, p 364).

Based on the foregoing, the Commission should reject the PFD's recommended long-term debt cost rate of 4.27% and adopt DTE Electric's recommended long-term debt cost rate of 4.29%.

2. Short-Term Debt Cost Rate

The PFD recommends that the Commission adopt Staff's recommended short-term debt cost rate of 3.85%. The PFD states that this rate, which utilizes a projected Short-Term Overnight Financing Rate (SOFR) of 3.41% from S&P Global, is a better practice for estimating rates in the test year than using the rate currently in effect. (PFD, p 366).

DTE Electric disagrees with the PFD's recommendation. As the PFD notes, in his rebuttal testimony, Company witness Lepczyk explained that given the consistently overly-optimistic forecasts of the possibility of rate cuts by the Federal Reserve, the Company continues to support the current, known short-term cost of debt as a more appropriate metric than the market's forecast rate. (Lepczyk, 4T 2928). Witness Lepczyk provided the example that the S&P Economic Outlook from December 2024 forecasted the average Federal Funds rate for 2025 to be 4.02%, while the actual average Federal Funds rate in 2025 was 4.33%. (Lepczyk, 4T 2928). He continued that due to the continued market volatility and unknown timing of Fed rate cuts, the Company feels it is reasonable and prudent to use the current and known short-term cost of debt rate, which he updated

to 4.69% calculated using DTE Electric’s actual borrowing rate in 2025 of 4.45% plus 0.24% for the cost of credit facility fees. (Lepczyk, 4T 2928). As summarized in DTE Electric’s Reply Brief, “[a]nchoring the short-term debt rate to observable pricing rather than speculative outlooks ensures rates reflect financing conditions rather than hoped for trends.” (DTE Electric’s Reply Brief, p 112).

Based on the foregoing, the Commission should reject the PFD’s recommended 3.85% short-term debt cost rate and adopt DTE Electric’s recommended short-term debt cost rate of 4.69%.

3. Return on Common Equity

The PFD recommends that the Commission reapprove DTE Electric’s current ROE of 9.90% for the test year. (PFD, p 208). The Company disagrees with this recommendation. The Commission should instead adopt DTE Electric witness Nelson’s recommendation that a just and reasonable ROE for DTE Electric’s common equity capital is 10.75%. This represents the midpoint of witness Nelson’s recommended range of 9.90% to 11.60% and is appropriate considering the increased cost of capital since DTE Electric’s last rate case and the business risks facing the Company.

As summarized in the Company’s Initial Brief, (DTE Electric’s Initial Brief, p 127), Company witness Nelson concluded that a range of 9.90% to 11.60% reflects investors’ required return for an equity investment in DTE Electric.²⁸ Within that range, she recommended an ROE of 10.75%, which is the midpoint of the range (Nelson, 4T 3010). She based her recommendation on her application of three widely accepted financial modeling approaches to a proxy group of 19

²⁸ DTE Electric has no preferred stock (Vangilder, 3T 1592; Exhibit A-14, Schedule D1, page 1, line 2).

electric utility companies: (1) the constant growth and quarterly growth forms of the Discounted Cash Flow (DCF) model; (2) the traditional and empirical forms of the Capital Asset Pricing Model (CAPM); and (3) the Bond Yield Plus Risk Premium approach. (Nelson, 4T 2943-2947). Each of these methodologies is discussed further later in this section.

As discussed in the Company's Initial Brief (pp 127-128), witness Nelson also assessed the Company's risk profile relative to the 19 proxy companies. Her recommendation considered the Company's significant capital investment needs, the effect of Michigan's clean energy mandates, the regulatory environment in which the Company operates, DTE Electric's financial risk reflected in its capital structure, and the current capital market environment. She clarified that while these factors are relevant to investors, their effect on the Company's cost of equity cannot be directly quantified. She emphasized that she did not make any explicit adjustments to her ROE estimates for the Company's business risks but rather considered them when determining her recommendation. (Nelson, 4T 2945).

Witness Nelson explained that capital costs have increased since the Company's last rate case and must be considered in recommending an ROE. (Nelson, 4T 3027, 3043). She testified that prevailing long-term bond yields have a significant impact on utilities' cost of capital, as well as on investors' assessment of a fair and reasonable return on invested capital. Citing the example that rising treasury yields signal to investors that they can earn a higher return investing in risk-free government bonds, she explained that, consequently, equity investors will expect higher returns when government bond yields rise. (Nelson, 4T 2946). She also noted in her direct testimony that authorized returns for vertically integrated electric utilities had actually increased with higher bond yields on a nine-month rolling average basis. (Nelson, 4T 2946-2947). She also explained that equity returns set when interest rates were very low in 2020 and 2021 are not a

reasonable basis of comparison for evaluating the authorized ROE for 2025 when bond yields have increased and are projected to remain elevated as inflation was still elevated. (Nelson, 4T 3019).

Witness Nelson also spoke to the significant capital investment DTE Electric plans to make in the next few years and the need for an adequate ROE for the Company to be able to secure financing on reasonable terms. (Nelson, 4T 2182). She described how the Company is planning to invest \$24 billion in new generation and reliability capital expenditures over the 2025 to 2029 period that includes approximately \$10 billion for cleaner generation investments, \$10 billion in distribution infrastructure investments, and \$4 billion in base infrastructure investments. (Nelson, 4T 2983). Notably, compared to 2023 net plant, the Company's capital investments over the next five years reflect a near doubling of net plant. (Nelson, 4T 2983). Additionally, meeting the ambitious renewable energy goals under Michigan law calls for significant deployment of new renewable generation resources. (Nelson, 4T 2983-2984). Witness Nelson also discussed how DTE Electric's capital expenditure requirements affect its risk profile and why credit rating agencies recognize the risks associated with elevated levels of capital expenditures, noting that "[m]aintaining access to capital markets on favorable terms is especially important for utilities and their customers during periods of significant capital investment." (Nelson, 4T 2984-2985). She noted that DTE Electric's ratio of projected capital expenditures to net utility plant is the highest of all the proxy companies and is higher than the median ratio for the proxy group of 53.85%. (Nelson, 4T 2986).

Although witness Nelson provided an extensive and robust evidentiary analysis, the PFD's primary basis for its recommendation is that the ROEs recommended by Staff, the AGO, ABATE, and CUB "are either identical, or within 10 basis points, of the recommended ROEs presented and evaluated by the Commission less than a year ago." (PFD, p 369). The PFD also notes that "except

for the AG's recommended range from the previous rate case, the results of the various analyses undertaken by Staff and intervenors are again remarkably similar." (PFD, p 369). The PFD concludes based on these observations that,

[g]iven the near identical results in both ranges and ROE recommendations, coupled with the short time since DTE's ROE was last authorized, this raises a question whether any change to DTE's ROE is justified. This PFD finds that it is not, despite the hundreds of pages of testimony and extensive arguments over proxy companies, appropriate betas, adjustments for financial risks, analytical flaws, or the comparability of ROEs authorized by other utility commissions. (PFD, p 370).

DTE Electric disagrees with the PFD's rationale. While it references the voluminous record in this proceeding addressing proxy groups and cost of equity methodologies and notes the "results of the various analyses undertaken by Staff and intervenors," the PFD does not otherwise mention, much less discuss, any of those methodologies (with the exception of the PFD's cursory dismissal of the ECAPM, addressed below). Instead, the PFD relies on the fact that Staff and other parties' recommendations are similar to their recommendations in the previous rate case, Case No. U-21534. The PFD does not engage with the analyses undertaken by witness Nelson (who notably did not present testimony in Case No. U-21534), which support adoption of DTE Electric's recommended ROE, or in fact with the analyses of any other ROE witnesses. The Commission has recognized, most recently in the Company's previous rate case, that each proceeding must be decided based on the evidence presented in that case. (Case No. U-21534 Order dated January 23, 2025, p 207 (citing Case No. U-21291, Order dated November 7, 2024, p 24 for the proposition that "[t]he Commission agrees that the evidence presented in each case should be considered in arriving at an approved ROE for the utility.")). Because witness Nelson's multiple analyses support DTE Electric's recommended ROE, they are addressed briefly further below.

The PFD also references that the Commission has authorized a ROE of 9.90% in every rate case since Case No. U-20561 (including Case Nos. U-20836, U-21297, and U-21534). (PFD, p

369). The Company disagrees with this retrospective rationale as well. The Commission should consider the evidence presented in this case to determine an approved ROE, consistent with the precedent cited above.

The Company recognizes that the Commission has stated that “it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions.” (Case No. U-18999 Order dated September 13, 2018, p 52). Here, the increased cost of capital, combined with the business risks facing the Company as discussed in witness Nelson’s testimony and the Company’s briefs represents a significant change in economic conditions that warrants an increase in DTE Electric’s authorized ROE.

Additionally, the PFD characterizes DTE Electric’s 10.75% ROE recommendation as an “outlier.” (PFD, p 369). The Company disagrees with this characterization; as discussed further below, witness Nelson’s direct and rebuttal testimonies present in detail the methodologies she used to determine an appropriate ROE in this proceeding, which resulted in her 10.75% recommendation. The Company also showed, as discussed in DTE Electric’s Initial Brief, pp 141-142, that its recommended ROE is in line with recent authorizations for similarly situated electric utilities. Given the foregoing, the fact that witness Nelson’s recommended ROE is higher than Staff’s or other parties’ does not on its own render it an “outlier” that justifies its dismissal without more fulsome evaluation and discussion.

Finally, the PFD notes that:

the Commission is currently considering a [performance-based ratemaking (PBR)] mechanism for both DTE and Consumers in Case No. U-21400, and is evaluating comments and reply comments on appropriate incentives and disincentives for improved reliability and performance. Because implementing such a mechanism may impact ROE in the future, this PFD finds that maintaining the status quo is appropriate, and consistent with the principles set out in *Hope* and *Bluefield*. Accordingly, this PFD recommends that DTE’s current ROE of 9.90% again be approved for the test year.

(PFD, p 370). DTE Electric takes exception to the PFD's recommendation to simply maintain the status quo at 9.90% to the extent that it is based on a separate, ongoing proceeding that "may impact ROE in the future." The preponderance of the evidence presented in this proceeding supports the Company's requested ROE based on the analyses conducted by witness Nelson and the significant capital investment plans and business risks facing DTE Electric. As noted above, the Commission has recognized that the matter of the ROE to be authorized for the Company must be decided based on the evidence presented in this case on that matter; ongoing, undecided matters in a separate proceeding should not be relied upon to support the Commission's determination on ROE in this proceeding.

a. DCF Estimates

Witness Nelson explained that the Constant Growth Discounted Cash Flow (DCF) approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. (Nelson, 4T 2961). Witness Nelson calculated the Constant Growth DCF result for each of her proxy companies using the following inputs: (1) average daily closing prices for the 30-, 90-, and 180-trading days ended January 31, 2025; (2) the current quarterly dividend as of January 31, 2025 multiplied by 4; and (3) long-term earnings per share (EPS) growth rate projections as of January 31, 2025, reported by Zacks, S&P Capital IQ, and Value Line for the long-term growth rate. (Nelson, 4T 2962). In order to provide a spectrum of DCF-based ROE estimates, witness Nelson calculated the low, mean, and high result for each proxy company using the low, mean, and high EPS growth estimate. The results of witness Nelson's Constant Growth DCF analysis ranged from a low of 9.54% to a high of 11.06%. (Nelson, 4T 2964-2965). Witness Nelson testified that the Quarterly Growth DCF model specifically incorporates the quarterly payment of dividends, which the Constant Growth DCF model does not account for, and the

associated quarterly compounding of those dividends as they are reinvested at the required ROE. (Nelson, 4T 2965-2966). The results of witness Nelson's Quarterly Growth DCF analysis ranged from a low of 9.76% to a high of 11.34%. (Nelson, 4T 2967).

Witness Nelson's rebuttal testimony responded to other witnesses' criticisms and their implementation of DCF models. (Nelson, 4T 3032-3033 (Staff), 3048-3051 (AG), 3063-3073 (ABATE)). Witness Nelson also updated her analysis to reflect market data as of July 31, 2025, with resulting constant growth DCF results ranging from 10.45% to 10.52% and quarterly growth DCF results ranging from 10.67% to 10.74%. (Nelson, 4T 3050-3051).

b. CAPM and ECAPM Estimates

Witness Nelson described the general form of the Capital Asset Pricing Model (CAPM) as a risk premium method that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. (Nelson, 4T 2967). Witness Nelson continued that the CAPM assumes that all non-market, or unsystematic, risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic risk. Systematic (or non-diversifiable) risk is measured by the Beta coefficient, which represents both relative volatility (i.e., the standard deviation) of returns, and the correlation in returns between the subject company and the overall market. (Nelson, 4T 2968-2969). For the risk-free rate of return component of the CAPM, witness Nelson applied both: (1) the 30-day average yield on 30-year Treasury bonds as of January 31, 2025 (i.e., 4.82%); and (2) a projected 30-year Treasury yield (i.e., 4.46%). For the Beta coefficient, she relied on the average Beta coefficients from Value Line and Bloomberg for each proxy company as of January 31, 2025. For the expected market return component, witness Nelson considered both: (1) a forward-looking estimate that calculates the market capitalization-

weighted ROE of the S&P 500 Index by applying the Constant Growth DCF model to the S&P 500 Index; and (2) the long-run historical arithmetic average market return of 12.17 percent reported by Kroll (formerly Duff & Phelps) for the years 1926 to 2024. (Nelson, 4T 2969-2970). Based on these inputs witness Nelson's analysis resulted in a range of 11.51% to 14.39%. (Nelson, 4T 2972-2973).

Witness Nelson also applied the Empirical CAPM (ECAPM) approach, which calculates the product of the adjusted Beta coefficient and the Market Risk Premium and applies a weight of 75.00% to that result. The model then applies a 25.00% weight to the Market Risk Premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result. (Nelson, 4T 2973). Witness Nelson explained that the ECAPM: (1) corrects the tendency of the CAPM to underestimate the cost of equity for companies, such as regulated utilities, with low Beta coefficients, and to overstate the cost of equity for companies with high Beta coefficients; and (2) recognizes academic research indicating that the risk-return relationship is flatter than the relationship estimated by the CAPM and that the CAPM under-estimates the alpha, or the constant return term, for companies with lower equity betas. The results of her ECAPM analysis ranged from 11.68% to 14.61%. (Nelson, 4T 2973-2976).

Witness Nelson's rebuttal testimony responded to other witnesses' criticisms and their implementation of the traditional CAPM model. (Nelson, 4T 3033-3034 [Staff], 3051-3058 [AG]).

The PFD states that "the Commission, like most commissions, has rejected" the ECAPM methodology." (PFD, p 368). The Company respectfully disagrees that the ECAPM has been explicitly rejected by the Commission and disagrees that it should be rejected here. First, as noted above, the ECAPM offers several benefits. (Nelson, 4T 2969-2970). Additionally, witness Nelson

fully addressed Staff's and other parties' testimony regarding the ECAPM in her rebuttal testimony. (Nelson, 4T 3035-3039). Further, while MNSC's Initial Brief recounts CUB witness Bandyk's testimony that the ECAPM has not been recognized by the Commission as a valid methodology for estimating ROE and Staff has historically declined to use it, MNSC cited in support previous PFDs but no Commission orders discussing this approach. (MNSC Initial Brief, pp 131-132). Finally, the Company presented evidence of the academic support for the ECAPM analysis, (Nelson, 4T 2975-2976, 3038, 3056-3057), and cases where the methodology has been accepted by state regulatory commissions, (Nelson, 4T 3038-3039, 3058).

c. Bond Yield Plus Risk Premium Estimate

Witness Nelson discussed how the Bond Yield Plus Risk Premium approach is based on the basic financial principle of risk and return, which states that equity investors require a premium over the return required as a bondholder to compensate for the residual risk associated with equity ownership. She stated that Risk Premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. (Nelson, 4T 2976-2977). Witness Nelson described the advantages of the Bond Yield Plus Risk Premium approach as: (1) accounting for authorized ROEs in other jurisdictions; (2) in conjunction with the DCF and CAPM approaches, adding diversity to the model results, enabling a more robust and reliable ROE estimate; and (3) being simpler and relying on fewer contentious inputs. (Nelson, 4T 2980-2981). The results of her analysis were a ROE of 10.20% based on a projected 30-Year Treasury and a 10.37% based on a current 30-Year Treasury. (Nelson, 4T 2979).

d. DTE Electric's Return on Equity in Relation to Risk

In its final order in Case No. U-20561, the Commission stated that it "will continue to monitor a variety of market factors in future applications, including market reactions to recent

events and measures of volatility and uncertainty, as well as measures of investor confidence, and the utility's risk profile," when determining an appropriate ROE. (Case No. U-21534 Order dated May 8, 2020, p 177). DTE Electric's Initial Brief, pp 142-146, discusses in detail the additional factors that directly bear on the Company's ability to earn a fair return and on its riskiness relative to the proxy group that were presented in witness Nelson's testimony and should be considered in terms of their overall effect on the Company's business risk and, therefore, its cost of equity. These factors include: (1) the Company's substantial capital expenditure program; (2) Michigan's ambitious clean energy mandates that the Company must meet; (3) the regulatory environment in which DTE Electric operates; and (4) economic and capital market conditions. As witness Nelson clarified, while these factors are relevant to investors, their effect on the Company's cost of equity cannot be directly quantified and she did not make any explicit adjustments to her ROE estimates for the Company's business risks. (Nelson, 4T 2945, 3120). The PFD does not mention or consider any of these factors; however, the Commission should take them into consideration as it has stated it would when determining the appropriate ROE in this proceeding.

e. Summary and Recommendations Regarding DTE Electric's Cost of Equity

The Commission should increase DTE Electric's ROE to 10.75% because the cost of capital investment has increased since the Commission maintained the Company's ROE at 9.90% in Case No. U-21534 and the Company continues to experience significant business risk as a vertically integrated generation owning electric utility with increased capital investment needs in the next several years. The average of witness Nelson's DCF, CAPM, and Risk Premium models results in a range of 9.90% to 11.60%, the midpoint of which is 10.75%. The Company's recommended 10.75% ROE is a reasonable and appropriate estimate of the Company's cost of equity, and the results of witness Nelson's updated DCF, CAPM, ECAPM, and Bond Yield Plus

Risk Premium analyses, together with her analyses of capital market data and the Company's risk profile, continue to support the reasonableness of this recommendation. (Nelson, 4T 3125). A 10.75% ROE is also in line with recent ROE determinations in other jurisdictions. (Nelson, 4T 3117-3119). Finally, a 10.75% ROE is important to maintain the Company's access to capital. Maintaining a solid credit rating and outlook is one important aspect to maintaining access to capital. A supportive allowed return on equity is important to ensure the utility's favorable access to credit markets. Maintaining a strong credit rating is particularly critical during a period forecast to have substantial capital investment for infrastructure. Therefore, the ROE of 10.75% recommended by the Company is appropriate given the business risks and increased cost of capital facing the Company and should be approved.

VII. ADJUSTED NET OPERATING INCOME

A. Operations and Maintenance Expense

As shown in Exhibit A-13, Schedule C5, the 2023 adjusted historical O&M expense reported by DTE Electric was \$1.173 billion, which the Company projected to increase to \$1.393 billion in the 2026 test year. Company witness Uzenski developed composite inflation rates for the projected test period. Witness Uzenski used labor and non-labor factors to calculate composite inflation rates of 3.4% for 2024, 3.0% for 2025, and 3.1% for 2026. (Uzenski, 4T 2423-2424; Exhibit A-13, Schedule C5.15).

1. Inflation

The PFD recommends inflation adjustments of 2.9% for 2024, 2.7% for 2025 and 2.4% for 2026, with no historical inflation adjustments. (PFD, p 102, 382). The PFD indicates that it "attempted to make appropriate inflation adjustments to O&M expense, in some cases this was not

possible due to time constraints.” (PFD, p 382). The PFD indicates that adjustments were made to incorporate the inflation rates recommended by the PFD for the following programs:

Steam Power Generation	(\$2,635,000)
Fuel Supply & MERC Fuel Handling	(\$119,000)
Nuclear Power Generation	(\$1,749,000)
Hydraulic Power Generation	(\$169,000)
Other Power Generation	(\$382,000)
Distribution	(\$4,165,000)
Customer Service	(\$1,347,000)
Regulated Marketing	(\$314,000)
Corporate Support	(\$23,545,000)
<u>IT O&M Expense</u>	<u>(\$1,101,000)²⁹</u>
Total	(\$35,526,000)

(PFD, p 382). The PFD cautions that the Commission should make the appropriate adjustments, based on the inflation rates the Commission approves, in its final order. (PFD, p 382).

For the reasons articulated above as well as Section V.D.2, while the Company agrees with the PFD’s use of the CPI-U inflation data in setting the inflation rates to be used for ratemaking purposes, the Company does not agree with the PFD’s rejection of the labor component of the Company’s proposed composite inflation rates. Therefore, the Company respectfully requests that the Commission accept the Company’s composite inflation rates, which, as the record reflects, are specifically tailored to reflect costs that the Company actually incurs. Such a decision would be

²⁹ The proposed inflation adjustment of \$1.1 million for IT O&M is already included in the Corporate Support line above and therefore is duplicative

consistent with the Commission's decision in its January 23, 2025 Order in Case No. U-21534, pp 74-75.

As described by Company witness Uzenski, administrative and general (A&G) O&M expense reflected in Exhibit A-13, Schedule C5.10 includes O&M for IT. (Uzenski, 4T 2445) The IT O&M exhibit (A-13, Schedule C5.13) sponsored by Company witness Ambrose serves only to provide additional information regarding the expenses embedded in Schedule C5.10. If an inflation adjustment is made based on the figures in the A&G O&M exhibit, an additional adjustment based on the figures in the IT O&M exhibit would be duplicative. Thus, if the Commission accepts the PFD's inflation adjustments, it should disregard the \$1.1 million reduction for IT O&M.

2. Steam and Hydraulic Power Generation O&M Expense (non-nuclear)

In this proceeding the Company requests \$197,831,000 for its steam power generation O&M expense. (Exhibit A-13, Schedule C5, line 1; Exhibit A-13, Schedule C5.1). The Company requests \$11,684,000 for its hydraulic power generation O&M expense. (Exhibit A-13, Schedule C5, line 4; Exhibit A-13, Schedule C5.4). Company witness Guillaumin supports the Company's projected O&M expense for steam power generation and for hydraulic power generation.

Staff recommends a significant reduction to the Company's projected steam power generation O&M expense. Specifically, Staff proposes a total reduction of \$20,158,000 to steam power generation O&M expense, which reflects eight specific adjustments. (Staff Initial Brief, p 139). Staff asserts that four adjustments are for projects that Staff identified as being one-time or infrequent projects. (Staff Initial Brief, p 141). For these projects, Staff determined that one-time and infrequent expenses should be recovered over a period of two years to protect rate payers from unreasonable future rates and, therefore, divided these expenses in half to allow recovery over two

years. (Staff Initial Brief, p 141). Two of the remaining four adjustments pertain to specific projects and the unique dynamics associated with each of those projects. (Staff Initial Brief, pp 141-145). Staff's seventh adjustment reduces the Company's periodic outage normalization adjustment shown on Exhibit A-13, Schedule C5.1 at footnote 5. (Staff Initial Brief, p 145). Staff's eighth adjustment is a reduction based on the application of Staff's proposed inflation rates. (Staff Initial Brief, p 148).

Staff recommended that the Company's projected hydraulic power generation O&M expense be reduced by \$131,000. (Kindschy, 5T 5105-5106). This adjustment reflects application of Staff's proposed inflation rates. (Staff Initial Brief, p 150).

The AG recommended a reduction of \$25.5 million to the Company's projected steam power generation O&M expense, based on an expense build-up for 2026 that the AG prepared from the Company's 2024 O&M expense schedule with adjustments to remove items that the AG deemed should not be included in the expense forecast. (Coppola, 4T 3529-3532). \$24.4 million of the \$25.5 million reduction recommended by the AG is simply based on inappropriately eliminating the Company's adjustments, with the balance attributable to the AG's lower proposed inflation rates. (Guillaumin, 3T 679).

The PFD agreed with Staff's adjustments, as modified in Staff's brief, "to Steam and Hydraulic Generation O&M expense." (PFD, p 387). The Company respectfully requests that the Commission disregard the PFD's recommendation for the following reasons.

First, with respect to Staff's recommendation related to hydraulic power generation O&M expense as well as Staff's reduction to the steam power generation O&M expense based on application of Staff's proposed inflation rates, the Company sets forth its position above that the Staff's proposed inflation rates are not reasonable. The PFD also declined to adopt Staff's proposed

inflation rates, (PFD p 102), so the recommendation to accept Staff's recommendation that is based on Staff's inflation rates is inconsistent.

Second, with respect to Staff's recommendation related to steam power generation O&M expense, the Company disagrees with the Staff's proposed reductions that would spread recovery of this expense over multiple years. The record reflects that the Company has presented reasonable support for completing these projects during the 2026 projected test year, (Guillaumin, 3T 668-674), and Staff does not specifically challenge the need for these projects or the Company's plans to execute them during the 2026 projected test year. (DTE Electric's Reply Brief, p 142). As explained by Company witness Guillaumin, the Commission should either approve full recovery now or authorize half now and commit to recovery of the remaining half in the next rate case, including the time value of money for 2026–2027. (Guillaumin, 3T 668).

With respect to the Company's periodic outage normalization adjustment, the Company understands that Staff has the following three concerns: (1) the historical years the Company used for normalization included actual expenses from a time period when the Company still planned to operate the Monroe Power Plant Units 3 and 4 beyond 2028; (2) the Company's actual spending in previous years does not support the level of forecasted periodic outage expenses in the projected test year of this case; and (3) the periodic outage normalization adjustment presented in the instant case is different from the calculation of the periodic outage normalization adjustment in the prior case, Case No. U-21534. (Guillaumin, 3T 675). The record reflects that the Company responded to each of these concerns as follows. The major maintenance planned for 2026 is not related to Monroe Units 3 and 4. Rather, the forecasted major maintenance occurring in the projected test year for steam units is the Belle River Unit 2 gas conversion outage and the Monroe Unit 2 major periodic outage, totaling \$26.9 million (\$13.9 million plus \$13.0 million, respectively). In 2023

the Company only incurred \$9.8 million of periodic outage expenses, mostly for major periodic maintenance on Monroe Unit 1. To normalize the 2023 periodic outage expense, the Company averaged the 2020-2022 actual periodic outage expenses adjusted for CPI to 2023 values. The difference between 2023 actuals and the 2020-2022 actuals adjusted for CPI was \$11.6 million. By adding the \$11.6 million to the 2023 historical test year, the Company included \$21.4 million (2023 dollars) in its request (\$9.8 million actual + \$11.6 million normalization). In terms of 2026 dollars, this adjustment is equivalent to \$23.5 million. In short, the Company's request in the instant case is already over \$3 million less than what it anticipates spending in 2026 (\$26.9 million forecast - \$23.5 million requested = \$3.4 million difference). (Guillaumin, 3T 675-676). Staff's proposed reduction creates a nearly \$8 million gap between the Company's planned work on Belle River Unit 2 and Monroe Unit 2 and the funding being approved in the instant case, which could result in reduced work and adverse impact to reliability. (Guillaumin, 3T 676-677).

With respect to Staff's concern that none of the Company's actual spending in previous years supports the level of periodic outage expenses in the projected test year, the Company explained that it is not requesting all of the forecasted 2026 steam periodic outage expenses in the instant case. The Company realizes that periodic outage expenses vary from year-to-year and thus has utilized a multi-year average of historical O&M expenses to normalize the 2023 expense. (Guillaumin, 3T 677).

With respect to Staff's concern that the calculation for the Company's 2023 periodic outage normalization in the instant case is different from the calculation in Case No. U-21534, the Company explained that the adjustment in the last case was strictly based on moving the cost of a single major periodic outage (Belle River Unit 2) from 2023 to 2024. It was not based on a multi-

year historical average, which, again was done in this case to normalize the 2023 test year expense to more closely reflect the Company's operational realities. (Guillaumin, 3T 676-677).

Finally, the PFD adopts the Staff's adjustment to the Belle River fuel handling expense, but does not acknowledge the fundamental misalignment between actual plant operations and the Staff's suggestion that converting one Belle River unit to gas obviates the need for 50% of the coal fuel handling equipment and labor. (PFD p.387). This is simply not true. As Company witness Guillaumin testified, DTE Electric would not incur less fuel handling costs due to the conversion of Belle River Unit 1 because all units are supplied by a common system of conveyor belts that bring coal into the plant, and reducing the number of coal fired units does not reduce the labor and other O&M costs required to operate this common conveyor belt system (Guillaumin, 3T 672-675). The Commission should recognize the actual plant operations and reject this disallowance.

Significantly, neither Staff nor the AG provide any evidence as to how the Company would meet its O&M obligations with the reduced funding for which these parties advocate. While the Company appreciates Staff's effort to ensure the reasonableness of every customer dollar spent, the Company must be in position to perform anticipated O&M in the interest of the reliable operation of the system, and disallowances should only be based on the required competent, material and substantial evidence on the record.³⁰ Based on this evidence of record, the Commission should disregard the PFD's recommendation and fund the Company's requests in full.

³⁰ *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency's decision was not supported by in evidence that a reasonable person would consider adequate).

3. Other Power Generation O&M Expense

In this proceeding, the Company requests \$39.6 million for its projected other power generation O&M expense. (Exhibit A-13, Schedule C5.5). This expense is supported by Company witness Guillaumin.

Staff and the AG proposed multiple reductions to the Company's projected expense. Specifically, Staff proposed a total reduction of \$5.51 million, which reflects two non-inflation reductions, \$914,472 for Trenton Channel BESS O&M and \$4,302,500 for the peaker increased maintenance expenses, and a \$295,000 reduction related to application of Staff's proposed interest rates. (Kindschy, 5T 5102-5103; 5105-5106, 5108). The AG proposed a total reduction of \$8.741 million to the projected expense, which is based on AG witness Coppola's use of 2024 actual normalized expenses as opposed to the test year, application of the AG's preferred inflation rates and selective elimination of several of the Company's adjustments, including a reduction of \$3,562,000 included by the Company as a normalization of the Blue Water Energy Center (BWEC) periodic spend. (Guillaumin, 3T 690).

The PFD finds that Staff's adjustments should be adopted. (PFD, p 397). Additionally, the PFD finds the AG's arguments persuasive and recommends disallowance of \$3,562,000 for BWEC normalization of periodic outage spending, concluding this expense is speculative. (PFD, p 397).

The Company disagrees with the PFD and respectfully requests that the Commission fund its request in full for the following reasons. First, Staff's reduction involves the halving of the peaker increased maintenance expense, which is unreasonable and not supported by record evidence. (Guillaumin, 3T 666). Witness Guillaumin proposed a reasonable alternative, which is either approve full recovery now, or if recovery is split over two cases, approve the deferred portion with the time value of money to avoid under-recovery of known test-year work. (Guillaumin, 3T

667-668). The PFD disregards this proposed alternative, noting only that “projections are speculative as to both timing and amount, and any additional peaker maintenance expense would simply continue into the next year.” (PFD, p 397). Staff does not specifically challenge the need for these projects or the Company’s plans to execute them during the 2026 projected test year. There is no evidence of record to substantiate Staff’s opinion that the Company’s expense projections are unreasonable or that the Company will not conduct the O&M as planned.

Second, the PFD’s acceptance of a \$4.302 million reduction to “peaker increased maintenance” disregards the record that 2024 reflected “barebones” work and that 2026 work scope is itemized and required to maintain safe, reliable, compliant operation as utilization increases. (Guillaumin, 3T 694-695).

Third, the PFD’s labeling of the Company’s BWEC *periodic-outage normalization* as “speculative” mistakenly conflates two different AG proposals for disallowance. The AG characterized a completely separate topic as “speculative”—BWEC *routine maintenance when equipment is no longer covered by warranty*,³¹ which the PFD did not recommend for disallowance, calling into question the basis for the PFD’s acceptance of the more significant \$3,562,000 proposed AG disallowance the PFD recommends. Further doubt results from the PFD’s disregard of the Company’s evidence that BWEC periodic outages occur on a four-year cycle, that 2026 outage O&M is forecast at over \$14 million. (Guillaumin, 3T 692-693), and because the PFD’s recommendation effectively strips out the Company’s levelization of BWEC periodic outage spending—a prudent expense supporting the execution of planned outage scope at BWEC. (DTE Electric Reply Brief, p 150). The AG’s Revised Initial Brief characterizes the proposed levelization of

³¹ On page 107 of the AG’s Revised Brief, the AG utilizes the word “speculative” to describe the \$0.4 million 2024 normalization adjustment for BWEC maintenance after the warranty period expires. (See Guillaumin Rebuttal, 3T 691-692) The slight increase in BWEC maintenance post-warranty was a distinct and separate contested issue from the \$3.6 million normalization of BWEC periodic outage spend.

BWEC periodic O&M as “unusual” and claims that, “[n]o adjustments have been proposed in the past for large increases in O&M expense for those power plants during periodic outages” (AG Revised Initial Brief, p 109). This claim is factually incorrect. The Company included periodic outage O&M adjustments for its steam units in Case No. U-20836 (Exhibit A-13, Schedule C5.1) and Case No. U-21534 (Exhibit S-16.7, page 1). The Company also included a periodic outage adjustment for BWEC in Case No. U-21534. (DTE Electric’s Reply Brief, p 150). Additionally, the AG’s Revised Brief incorrectly claims the only explanation for BWEC expenses increasing from \$9.5 million in 2024 to \$24.6 million in 2026 is inflationary adjustments. (AG Revised Initial Brief, p 108). In fact, in a discovery response, the Company explained that it estimated 2026 BWEC account-level expenses by applying annual inflation adjustments to 2023 normalized account-level values and adding the total forecasted BWEC 2026 Periodic Outage.” (DTE Electric’s Reply Brief, pp.150-151; Exhibit A-54, Schedule UU4). The Company also refuted the AG’s argument that not operating BWEC should offset most of the \$14 million in periodic outage costs (AG Revised Initial Brief, p 108 and PFD p 391). Specifically, the Company explained that O&M expenses actually *increase* during periodic outages and it is unreasonable to conclude a \$14 million periodic expense can be absorbed by \$10 million of annual non-periodic O&M funding (Guillaumin, 3T 692-693). Finally, the Company explained how BWEC is unique and separate from the Company’s steam fleet and peaker fleet. While annual periodic outage expenses tend to levelize in a larger fleet of units (like the Company’s steam fleet and the peaker fleet), BWEC is the Company’s only combined cycle power plant and, thus, periodic expenses are expected to be “lumpy”, occurring once every four years (Guillaumin, 3T 693 and Exhibit AG-72 p 6). At bottom, the proposed disallowance of the Company’s BWEC periodic outage O&M levelization adjustment provides no funding to perform reasonable and prudent periodic outages at BWEC.

In sum, the PFD’s recommendation disregards operational realities, substitutes unsupported assumptions for the Company’s planning, and would underfund essential maintenance at the expense

of reliability and customer outcomes. Accordingly, the Commission should reject the PFD's recommendation regarding the Company's other power generation O&M expenses and fund the Company's request in full.

4. Midwest Energy Resources Company Fuel Supply Expense

The PFD recommends approving the Company's MERC O&M expense and regulatory liability treatment but applies adjusted inflation rates that reduced the Company's recoverable expense by \$119,000. (PFD, p 400-401). The Company takes no exception with the PFD's general recommendation for approval of MERC O&M expense, and the Company presents its exceptions opposing the PFD's recommendation to reduce the inflation rate in Section VII.A.1 above.

5. Nuclear Generation O&M Expense

The PFD generally recommends approving the Company's Nuclear O&M Expense and rejects the AG's proposed disallowance, finding persuasive DTE Electric's explanation that the Company's staffing level at the Fermi 2 plant is "insufficient, and that DTE is endeavoring to correct this situation, consistent with the requirements of its operating license." (PFD, p 408). However, the PFD applies adjusted inflation rates, reducing the Company's nuclear power generation O&M expenses for the forecasted test period by \$1.749 million. (PFD, p 407-408). The Company takes no exception with the PFD's general recommendation for approval of the Company's nuclear generation O&M expense. The Company presents its exceptions opposing the PFD's recommendation to reduce the inflation rate in Section VII.A.1 above.

6. Distribution Expense

The Company projects \$505.5 million of Distribution O&M expenses for the projected test year (Kryscynski, 3T 1186; Exhibit A-13, Schedule C5.6, page 1, line 27, column (1)). This

consists of approximately \$143.0 million in projected distribution operation expenses and approximately \$362.5 million of maintenance expenses. (Kryscynski, 3T 1186). The operation expenses relate to supervision, engineering, load dispatching, station, overhead and underground line operations, and customer meter and installation activities, among other distribution costs. The maintenance expenses relate to inspecting, repairing, sustaining, and enhancing the distribution infrastructure, with funds allocated for the upkeep of station equipment, overhead and underground lines, and line transformers. (Kryscynski, 3T 1187).

a. Distribution Base O&M Expense

The PFD generally accepts the Company's request for its base O&M expense, including the Company's normalization. However, the PFD recommends a reduction of \$2.128 million related to consulting fees, as advocated for by the AG, concluding that the Company did not adequately support this cost. (PFD, pp 410-411). The PFD also recommends a decrease of \$12.044 million related to the CDA normalization.

The Company disagrees with the PFD's reduction related to consulting fees, because as testified to by Company witness Kryscynski, "[c]onsultants allow the Company to flexibly support short term priority needs and temper the need to hire more full-time staff." (Kryscynski, 3T 1255). Emphasizing that temporary reductions to O&M allowed the Company to manage short-term challenges, witness Kryscynski explained that "these reductions are not viable as a long-term strategy." (Kryscynski, 3T 1255). His testimony emphasized the value provided to customers by contract labor—allowing the company to contract for labor only when the work need is present and not maintain a full-time staff for work that is not full-time—and highlighted that the ability to ramp up a workforce through contracting is "essential to sustaining core operations, ensuring continuity of business functions, and maintaining compliance and performance standards."

(Kryscynski, 3T 1255). Because the use of contract labor provides value to customers for the reasons explained by witness Kryscynski, the Company respectfully requests that the Commission disregard the PFD's recommendation regarding this portion of the base O&M expense.

The Company also takes exception to the PFD's disallowance related to the application of CDA to emergent expense. The Commission should allow the use of CDA for restoration expense in light of the substantial evidence provided by the Company, as discussed in Section V.D.3.a. In particular, the Company provided definitive evidence that labor costs, the primary component of restoration expense, have increased annually since 2019 and will continue to do so into the projected test year. (Hill, 4T 2764) As storm response costs are primarily driven by labor, the PFD's rejection of CDA disregards this critical data point. (Kryscynski, 3T 1257).

Should the Commission reject the application of CDA, the Commission should not ignore the error identified in Mr. Coppola's calculated disallowance of \$12.044 million (which the PFD adopts). Specifically, Mr. Coppola's calculation omitted \$1.495 million for non-storm restoration expenses which results in a disallowance of \$10.549 million and not \$12.044 million (Kryscynski, 3T 1257-1258).

b. Tree Trimming

i. Funding and Specification Changes

The Company's distribution base O&M request for 2026 includes \$180 million for tree trimming. Exhibit A-13, Schedule C5.6, page 1, Line 19; Exhibit A-13, Schedule C5.6.1. The funding requested by the Company includes \$35 million for the incremental costs associated with executing three proposed specification changes, including: (1) the removal of certain overhang; (2) the clearing of the floor, which is the area directly under overhead equipment; and (3) addressing outside-the-right-of-way (OROW) trees that pose a risk to overhead equipment.

(Steudle, 4T 2882, 2866).

Staff supports the Company's full request of \$180 million for tree trimming O&M. (Duell, 5T 5261-5262). Staff witness Duell testified that while Staff supports the Company's proposal related to the removal of overhang, Staff would like a report from the Company within 2 years of the completion of the instant proceeding related to this specification change. (Duell, 5T 5264). Company witness Steudle testified that DTE Electric is supportive of Staff's recommendation to provide a report related to overhang; however, the Company would like to collaborate with Staff to refine the parameters of the report. (Steudle, 4T 2887). Staff agreed to collaborate with the Company on the report. (Staff's Initial Brief, p 217).

The PFD finds the Company's proposed specification changes to be in line with the Commission's June 12, 2025 Order in Case No. U-21305 and recommends approval of the Company's three proposed specification changes. Further the PFD agrees with Staff's recommendation, as agreed to by DTE Electric, that the Company provide a report within two years of the completion of this rate case on the implementation and results of the three proposed specification changes, with the specific contents of the report to be determined by the Company and Staff. (PFD, p 436). The Company agrees with these recommendations of the PFD and respectfully requests that they be adopted in the Commission's final order.

However, the PFD also recommends removal of \$8.322 million from the Company's proposed \$35 million specification change expenditures for the test year, based on contention from the AG that the Company failed to adequately support \$3.5 million for the inspection and planning for OROW tree removal, \$2.5 million for customer outreach and call center support, and \$2.322 million for additional trees to be removed. (PFD, p 436-437).

The Company disagrees with this recommendation. As testified to by Company witness Steudle, these costs are incremental to the Company's proposed base plan and are necessary to

fully support the specification changes. (Steudle, 4T 2885). The \$3.5 million cost for inspecting and planning OROW trees is necessary because the Company is doubling the distance outside the ROW for which at-risk trees are identified, incorporating these inspections into the midcycle inspections, and leveraging certified arborists to assess tree health and risk of failure. (Steudle, 4T 2885). In addition to an increase in time spent identifying trees that must be removed, this will require face-to-face communication with homeowners (based on experience gained during the Surge) and engagement to gain permission to remove trees. (Steudle, 4T 2885-2886). The \$2.5 million for additional customer outreach is based on the Company's reasonable anticipation that the increase in vegetation removal will lead to an increase in customer escalations, inquiries and complaints. An increase in call center staffing levels to handle the increased call volume and an increase in education and proactive communication to customers around the tree trimming program and benefits of vegetation removal will be funded with the \$2.5 million. (Steudle, 4T 2886). With respect to the \$2.3 million for small tree removals, the Company's base plan was built on historical cost per mile and tree removal rates. The \$2.3 million reflects the incremental cost to remove the trees that historically had been trimmed. The base plan reflects only trimming these trees as opposed to removing them. (Steudle, 4T 2886-2887). Based on this evidence, the Commission should, consistent with Staff's support for the full cost request, find that the Company has adequately supported these costs and approve full recovery, in the interest of ensuring that the Company is in a position to proceed as planned with its specification changes.

ii. Risk-Based Approach

The Company also proposes, as a post-Surge tree trimming program, to shift toward a risk-based cycle instead of remaining on a fixed 5-year cycle. (Steudle, 4T 2859). Beginning in 2022, the Company recognized opportunities to adjust the target cycle for different parts of the system

utilizing technology such as Light Detection and Ranging (LiDAR), a remote sensing technology that uses laser light to identify and measure vegetation risk. Adjusting cycle lengths based on tree species' growth rates, risk of outages, and cost of trimming will further improve trimming efficiencies and provide improved reliability benefits to customers. With the acquisition of LiDAR data (2021) combined with tree species data acquired over the course of the Surge program, the Company now has the necessary information to make data-driven improvements to its tree trimming program. (Steudle, 4T 2859-2860). The emergence of remote sensing tools such as LiDAR and advanced data analytics for vegetation management programs will enable the Company to develop variable cycles that are tailored to the Company's overhead circuits' unique risk factors. (Steudle, 4T 2860). Risk-based cycles were endorsed in the Liberty Audit. (Steudle, 4T 2860).

The PFD, however, recommends that the Commission direct the Company to proceed with a consistent five-year trimming cycle for all trees, as opposed to employing the risk-based approach, citing concerns raised by Staff, NRDC-CUB, and Ann Arbor. (PFD, p 435). The PFD suggests that the recommended approach is consistent with the Commission's June 12, 2025 Order in Case No. U-21305, which provides that "[a]t a minimum, the Commission does not want to lose the progress that has been made by achieving the five-year tree trimming cycle. The Commission recommends that the company stay on the five-year cycle while investigating the additional benefits of moving to a four-year cycle." (June 12, 2025 Order in Case No. U-21305, p 17). The PFD also recommends that the Company investigate the costs and benefits of moving to a 4-year cycle, explaining in detail its advantages and disadvantages, and provide a report to the Commission on its findings. The PFD suggests that the Company, in this report, make a comprehensive case supporting risk-based cycling for the Commission's review and consideration.

(PFD, p 436). However, the Company did not arbitrarily and without support from the Commission and intervenors, explore the benefits of adopting a risk-based approach. The idea of variable cycles was raised by intervenors and the Commission in Case No. U-20836. Specifically, the Commission stated in its U-20836 Order that “DTE Electric is expected to provide an update on its analysis regarding its tree trimming program, including improving efficiency and evaluating potential benefits from utilizing a variable cycle, as the ALJ concluded.” (Case No. U-20836 Order dated November 18, 2022, p 479).

The Company respectfully submits that the record in this proceeding contains substantial evidence supporting the Company’s transition to a risk-based approach. Critically, the Commission’s June 12, 2025 Order in Case No. U-21305 was issued prior to consideration of the evidence in this case. The record in this proceeding provides the Commission with new evidence that reasonably leads to a conclusion that the Company’s approach meets the Commission’s concerns related to the Company’s tree trimming practices, notwithstanding its conclusions in its previous order. Notably, risk-based cycles were endorsed in the Liberty Audit. (Steudle, 4T 2860).

Additionally, the record reflects that the Company expects that moving towards a risk-based cycle will result in trimming efficiencies and improved reliability for high-risk areas. Based on the nature of variable cycle programs, the Company anticipates the need to trim high-risk areas more frequently and low-risk areas less frequently, resulting in an overall more efficient use of resources. In addition, more frequent trimming in high-risk areas should provide reliability benefits to customers without sacrificing reliability in low-risk areas. (Steudle, 4T 2861). The Company developed a risk prioritization model that leverages remote sensing data (e.g., LiDAR), advanced analytics, and machine learning to estimate the probability of vegetation-driven failures and determine optimal trim cycles for each individual circuit. (Steudle, 4T 2861-2862). This is exactly

the type of risk-based approach that intervenors have long argued for in the Company's various proceedings before the Commission.

Company witness Steudle explained that the Company has already deployed the risk prioritization model to defer miles already trimmed to the ETTP specification that are due for trimming based on the five-year cycle. (Steudle, 4T 2862). The PFD misinterprets what the Company has achieved in this regard. Using the model, the Company prioritized higher risk areas and deferred action on certain circuits that would have been due for trimming based on the five-year cycle, because these areas were determined to be low risk. This directly benefits customers. As witness Steudle pointed out:

[T]he model was used to defer approximately 2,000 "on-cycle miles from 2024 and 3,700 "on-cycle" miles from the 2025 plan. As noted in my direct testimony on page 19, the results of these deferrals were promising. The SAIFI for circuits deferred in 2024 was 0.15 while the overall system SAIFI was 0.18. In other words, the results of these deferred circuits were on par with the system average for 2024.

(Steudle, 4T 2893). The Company has developed a data-driven approach to optimize resources to address areas with a greater reliability risk. (Steudle, 4T 2865). This approach balances reliability results and the costs to achieve them. (Steudle, 4T 2893).

When fully implemented to include both pull ahead (4-year cycle miles) and deferred miles, the Company estimates the average cycle length will be 5.8 years for distribution miles. (Steudle, 4T 2864). Furthermore, as explained by witness Steudle and further illustrated in Table 3 of her rebuttal testimony, although more than half of its circuit miles are expected to be on a trim cycle greater than the current five-year program, the vast majority of customers- *more than two-thirds*- will remain on a five-year cycle or will move to a four-year cycle. In fact, almost 40% of customers will move to an accelerated 4-year cycle under the Company's proposal. (Steudle, 4T 2864, 2892). In addition, for circuits that are identified for a longer trim cycle, the Company will

put in place a mid-cycle inspection program to allow for the Company to identify and address hot spots. (Steudle, 4T 2896).

Moving from a five-year distribution cycle to a four-year cycle would increase costs, as both witness Steudle and the Liberty Audit point out. (Steudle, 4T 2891). Moving into 2026, the Company's proposed test year budget of \$180 million includes trimming circuits based on their unique risk profiles as opposed to a fixed five-year cycle. (Steudle, 4T 2893-2894). The Company estimates that the incremental cost of moving from a 5.8-year average risk-based trim cycle to a fixed-year trim cycle was estimated to be at minimum \$20 million dollars more than the Company's current \$180 million request for 2026. The Liberty Audit estimates an additional \$40 to \$50 million dollars in moving from a 5- to 4-year trim cycle. (Steudle, 4T 2896-2897).

The Company's approach reflects a data-driven strategy that directs resources more efficiently and more effectively and to where they have the greatest benefit. The risk-based method accelerates the tree-trim cycle for approximately 40% of customers while demonstrating deferred customers receive service consistent with the system average. By optimizing resources, the Company strengthens reliability with financial efficiency. For these reasons, the Commission should not accept the PFD's recommendation and should, instead, allow the Company to move forward with its risk-based tree trim approach.

Lastly, as explained in the Company's Reply Brief, the requested \$180 million in O&M funding is incompatible with the 6,554 miles required to be trimmed under a 5-year fixed cycle. A collaborative approach with Staff would help align expectations as to how the Company can best optimize its approved funding in terms of miles and specification changes for the test year in the instant case. The PFD did not take a position on this request, leaving a critical issue unresolved. The Commission should recognize that, while the Company strongly recommends adoption of its

proposed risk-based approach, if the Commission does not do so, the Company will not be able to trim the required miles in the test period aligned with a fixed five-year cycle with the requested O&M funding in the instant case of \$180 million.

c. Staking and Locating

The Company's requested distribution base O&M expense includes \$605,000 for MISS DIG Fees and \$10,492,000 for contractor staking expense, for a total damage prevention expense of \$11,098,000. (Exhibit A-13, Schedule C5.6, page 4).

The AG took issue with the \$ 2.9 million adjustment in the projected test year over the 2023 expense, arguing that the Company's adjustment is overstated for several reasons, including that inflationary cost increases should not be added to contractor cost increases because the inflation increases reflect increases in prices and that the forecasted volume increase for additional staking and locating requests is unsupported. (Coppola, 4T 3526). The AG contended that the purported inflation increase was "worth about \$675,000." (Coppola, 4T 3526). Ultimately, the AG recommended reducing the adjustment by \$1.618 million, which reflects incremental adjustments made by the Company. (Coppola, 4T 3527).

Although the PFD acknowledges that staking volumes, contractor costs and MISS DIG fees have increased, it also concludes that the AG is correct in suggesting that adding inflation to contracted expenses for inflation appears incorrect. Ultimately, the PFD recommends that the inflation adjustment be removed from this category of expense. (PFD, p 440).

The Company disagrees with the PFD on this issue. The AG's \$675,000 "duplication" claim was not supported by a calculation in testimony or exhibits and should be rejected on that basis alone. (Hill, 4T 2830). No other party, including Staff, took issue with the Company's adjustment of this expense for inflation. The Company's funding request is based on documented

operational requirements to meet statutory MISS DIG obligations and is not discretionary spending. (Hill, 4T 2831). As the Company has explained in this case, the AG's recommendations are not grounded in the practical conduct of the Company's O&M activities and obligations, and reductions to funding requests now will only exacerbate O&M demands in the future. (DTE Electric's Initial Brief, p 163). For these reasons, the Commission should reject the PFD's recommendation to remove the inflation adjustment from this expense category.

7. Customer Service Expense

a. Merchant Fees

The PFD notes that DTE Electric withdrew its request for \$7.013 million in the test year for residential merchant fees and the issue is, therefore, now moot. (PFD, p 458). The Company's take no exception with this finding, but notes that the capital costs for the Payment Merchant Fees IT project is necessary as a result of this withdrawal. See Section V.G.1.e. for the Payment Merchant Fees IT project necessary to collect credit and debit card transaction fees. The removal of merchant fees from the Company's revenue deficiency is discussed further above.

8. Regulated Marketing Expense

The PFD recommend that the Commission adopt the AG's proposed regulated marketing O&M expense of \$29.358 million for the 2026 test year in lieu of the Company's projected \$32.097 million for the 2026 test year, resulting in a disallowance of \$2.739 million. The Company disagrees with the PFD's proposed disallowance because the PFD also rejects the AG's exclusion of two normalization adjustments to historical expense totaling \$4.909 million for MI Green Power program outreach and marketing and deferred backfilling of employees. (PFD, p 467). Company Witness Foley testified that these adjustments are necessary regardless of whether 2023 or 2024

historic data is used as the basis for the test year projection because these costs will be incurred in the 2026 test year (Foley, 4T 2676-2678). If the AG's exclusion of normalization expense is rejected, the total O&M expense would be \$34.267 million. Accordingly, the Company requests that the Commission reject the \$2.739 million proposed disallowance.

Staff witness McMillan-Sepkoski recommended a decrease of \$244,000 in regulated marketing O&M due to Staff's proposed inflation rates (McMillan-Sepkoski, 5T 4983-4984). The PFD does not directly address this issue but notes that "inflation is dealt with elsewhere in this PFD" and recommends a \$314,000 reduction based on proposed inflation rates as discussed in Section VII.A.1 above (PFD, p 327, 382). The Company continues to disagree with Staff's proposed disallowance, as discussed in briefing (DTE Electric's Initial Brief, p 215, DTE Electric's Reply Brief, p 199) and takes exception with the PFD's proposed disallowance as well.

9. Corporate Support

The PFD recommends that the Commission disallow the Company's recovery of \$1,476,202 in O&M expenses for Edison Electric Institute (EEI) membership expense, arguing that the Company did not appropriately comply with past Commission orders to itemize projected costs associated with membership fees,³² explain why such costs are in customers' interest,³³ provide a detailed description of how such memberships specifically impact and benefit customers,³⁴ and discuss the processes, projects, and procedures benefitting the Company's customers that have resulted from such memberships.³⁵ (PFD, p 475). The PFD recommends that the Commission reiterate its previous directives and additionally provide a "detailed and itemized

³² Case No. U-20836 Order dated November 18, 2022, p 308.

³³ *Id.*

³⁴ Case No. U-21297 Order dated December 1, 2023, p 221.

³⁵ Case No. U-21534 Order dated January 23, 2025, p 466.

list of expenditures, with names of vendors and a detailed description of the nature of the expenses, of DTE's spending on electoral campaigns, advertising, marketing, lobbying, trade associations, and 501(c)(3) and 501(c)(4) non-profits." (PFD, p 475).

The Company takes exception with the PFD's proposed disallowance. As explained in the Company's Reply Brief, the Company has provided significant evidence explaining how its EEI membership benefits customers, consistent with the Commission's prior directives, through Exhibit A-27 and the rebuttal testimony of witness Leslie. (Leslie, 3T 1033; Exhibit A-27, Schedule Q1). The PFD dismisses this evidence, arguing that it fails to list any tangible benefits to customers or discuss "processes, projects, procedures or other tangible impacts benefitting ratepaying customers." (PFD, p 475). To the contrary, however, witness Leslie provides a detailed narrative explaining how the Company leverages its participation in EEI to benefit its customers through specific operating groups and workstreams. For example, witness Leslie describes that the Company relies on EEI for support related to:

- (1) Mutual assistance coordination across the nation that enables the Company to quickly secure resources for storm restoration. EEI is the only entity that provides mutual assistance structure in the industry;
- (2) Information on technology industry security initiatives and best practices;
- (3) Assistance identifying networking with diverse suppliers specific to the utility industry as well as sharing best practices regarding supplier diversity
- (4) Benchmarking on utility-driven economic development;
- (5) Benchmarking around solar and battery storage commissioning strategies and best practices;
- (6) Benchmarking around uncollectible expenses and a better understanding of state policies that drive external and internal programs to assist customers;
- (7) Surveys to understand tariff impacts on key supply chain materials;

- (8) Sharing of best practices from transportation electrification programs around the nation; and
- (9) Learning from industry experts and leaders on important topical subjects such as battery operations and risk mitigation as well as decarbonization. (Leslie, 3T 1034-1035)

DTE Electric, through witness Leslie, has provided detailed information explaining how the Company participates in EEI and how that participation improves the Company's operations to the benefit of customers. (Leslie, 3T 1034-35; DTE Electric's Reply Brief, pp 167-168). This evidence presents "tangible benefits justifying why the costs are in the customers' interest" which the PFD suggests is lacking. (PFD, p 474). Moreover, the Commission found this level of detail to be reasonable and "sufficient to approve recovery" in Case No. U-21534, noting that EEI's mutual assistance coordination "has proved invaluable to customers in restoring outages during and following severe weather."³⁶ The PFD appears to argue that the Commission directed the Company to provide additional details in its next rate case, including by describing the Company's "roles and responsibilities in advancing ratepayers interests through its participation in each organization." (PFD, p 473-474 (*citing* Case No. U-21534 Order dated January 23, 2025, p 243)). In fact, though, the Commission articulated this requirement as specifically applicable to DTE Electric's membership and participation in the Center for Energy Workforce, the Human Capital Institute, and The Institute for Corporate Productivity—and *not* to the Company's EEI membership or other discretionary corporate memberships.³⁷ The Company made this point in its Reply Brief at page 169, but the PFD does not directly address it in recommending disallowance of the \$1,476,202 in EEI membership dues.

³⁶ Case No. U-21534 Order dated January 23, 2025, pp 243-244.

³⁷ Case No. U-21534 Order dated January 23, 2025, p 244.

The PFD also suggests that “the Company asks the Commission to take at face value its assertion that any costs associated with lobbying activities have been excluded from its recovery requests without providing evidence.” (PFD, p 474-475). This conclusion disregards the testimony of Company witness Uzenski as well as the Company’s Reply Brief. Specifically, witness Uzenski explains that the Company excludes the actual amount of membership dues identified by EEI as attributable to lobbying and advocacy expenses from its recovery request. (Uzenski, 4T 2411-2412; Exhibit A-3, Schedule C1.1); DTE Electric’s Reply Brief, pp 170-171). Furthermore, DAAO submitted evidence that EEI is required by federal law to report its lobbying expenses to Congress on a quarterly basis and, based on that federally reported information, reports to members the actual percentage of dues used for lobbying expenses at the end of the year. (Exhibit DAA O-32, p 3).

For all of these reasons, the Commission should reject the PFD’s recommended disallowance and find the evidence presented by the Company in this case to support corporate membership dues is reasonable, responsive to the Commission’s prior directives, and fully approve the Company’s projected test period expense for corporate membership dues, consistent with its decision in Case No. U-21534.

Separately, the PFD appears to make a *sua sponte*³⁸ recommendation that the Commission direct DTE Electric to provide a detailed and itemized list of expenditures, with names of vendors and a detailed description of the nature of the expenses, the Company’s spending on electoral campaigns, advertising, marketing, lobbying, trade associations, and 501(c)(3) and 501(c)(4) non-profits. DTE Electric takes exception to this recommendation as the ALJ’s *sua sponte* raising of an independent recommendation in the PFD is not only contrary to the “contested case” provisions

³⁸ *Sua sponte* is generally defined as: “Without prompting or suggestion; on its own motion.” *Black’s Law Dictionary* 1560 (9th ed. 2009).

of the APA, but also inconsistent with the adversarial system of adjudication as generally practiced throughout Michigan and the United States. Some guidance is provided by *Chen v Holder*, 737 F3d 1084 (7th Cir 2013), where the Seventh Circuit Court of Appeals explained in part:

“...[Judges] cannot write a party’s brief, pronounce ourselves convinced by it, and so rule in the party’s favor. That’s not how an adversarial system of adjudication works. Unlike the inquisitorial systems of Continental Europe, Japan, and elsewhere, our [adversarial] system is heavily dependent on the parties’ lawyers for evidence, research, and analysis.” *Chen, supra*, 737 F3d at 1085 (Emphasis added).³⁹

Nor is there any defined purpose to the recommended reporting, particularly where these expenses are not included in rates, and those that are included are discussed in testimony (see e.g. Uzenski 4T 2410-2412, Exhibit A-27, Schedule Q1). Nevertheless, as part of its Integrated Resource Plan settlement in Case No. U-21193, the Company already provides this type of information on its website. Further reporting is neither justified nor necessary.

10. Pension and Benefits

a. New Hire Voluntary Employees Beneficiary Association

As described by DTE Electric witness Cooper, the New Hire Voluntary Employee Benefit Association (VEBA) program costs reflect the costs of benefits that are offered in lieu of the traditional retiree healthcare plan for eligible employees, as adjusted for the portion of costs capitalized. The Company’s traditional retiree healthcare plan is closed to new participants, so the costs of the New Hire VEBA plan are offset by avoided OPEB costs. (Cooper, 3T 1533-1536; Exhibit A-13, Schedule C5-11, page 2, line 4). Witness Cooper explained that in 2023, the Company recognized an unusually high true-up adjustment related to the New Hire VEBA costs

³⁹ The opinion was by Judge Richard Posner, who is generally held in high regard as a scholar and jurist.

recognized in 2022 compared to the actual funding requirement for 2022. Specifically, the 2022 true-up reflected as a reduction to the Company's 2023 New Hire VEBA costs was \$2.920 million, whereas the average of the five prior years true-up adjustments was only \$0.439 million. Accordingly, the Company's 2023 costs were thus uncharacteristically understated by the difference between the 2023 actual of \$2.920 million and the five-year average of \$0.439 million, or \$2.481 million, which after reduction for the proportion of costs capitalized in 2023 of 44.6%, understated the Company's expense by \$1.375 million. (Cooper, 3T 1535).

The PFD does not accept DTE Electric's normalized calculation of New Hire VEBA program expenses, instead recommending the Commission adopt an alternative VEBA expense calculation methodology recommended by AG witness Coppola. (PFD pp. 483-484) The Company takes exception to this recommendation for reasons below, and as previously advanced by witness Cooper in rebuttal testimony and further supported in DTE Electric's Initial and Reply briefs. (Cooper, 3T 1558-65; DTE Electric's Initial Brief, pp 179-181; DTE Electric's Reply Brief, pp 173-176).

As DTE Electric witness Cooper explains, both AG witness Coppola's and Staff witness Rueckert's proposed adjustments to VEBA expenses are flawed and fail to reasonably adjust for abnormal recent events that have actually impacted VEBA expense forfeitures in 2022-2023 (COVID-19 pandemic) and 2024 (excess true ups and the impacts of lag hiring) (Cooper, 3T 1560). More specifically, DTE Electric's proposed normalization adjustment based on the five-year average of true ups for the years 2017-2021 was consistent with the methodology ordered in the Company's most recent rate case without objection. (Order, Case No. U-21534, p. 245; Cooper, 3T 1563). Moreover, DTE Electric supports its methodology by pointing to the Commission's determination in the Case No. U-21534 Order that it was reasonable to recognize the abnormal

impact of the COVID-19 pandemic by excluding the years 2021 and 2022 when determining a reasonable approach to normalize Employee Savings Plan expense, a determination that is equally applicable here. (Cooper, 3T 1563; Case No. U-21534, Order dated January 23, 2025, p 250). Witness Cooper also explains that the VEBA expense escalation rates used by Staff witness Rueckert and by AG witness Coppola are unreasonably low and fail to adjust the Company's recorded VEBA costs for the actual impacts of the abnormally high excess true ups in 2022, 2023, and 2024. (Cooper, 3T 1564). DTE Electric also demonstrated in the record the reasonableness of its VEBA expense calculation methodology by adjusting Staff's annual average escalation to reflect the impact of the excess true ups that occurred in 2022, 2023 and 2024. Additionally, the Company recomputed Mr. Rueckert's projected VEBA expense based on the normalized 2024 starting point and the 7.82% annual escalation, resulting in a projected expense of \$8.150 million, which is \$2.148 million more than Mr. Rueckert's projection. This analysis reflects a substantially higher average annual percentage increase than the compound annual growth rate of 1.5% computed by AG witness Coppola for the years 2020 through 2024. (Cooper, 3T 1564-65). The Company maintains that the surge in forfeitures experienced in 2022 and 2023 were "unrepresentative of a normal level of forfeitures" and "reflects the transitional impact of a once in a century pandemic." (DTE Electric Reply Brief, p 175). In sum, the Company explained in its Reply Brief that its VEBA expense normalization approach is reasonable based upon the actual excessive true-ups and the Commission's recent Case No. U-21534 Order on the reasonableness of excluding the abnormal years.

DTE Electric disputes the PFD's assertion that the five-year average of VEBA expenses for the years 2017-2021 is arbitrary and "outdated" when the Company's more recent experience in 2022, 2023, and 2024 is not representative of reasonably anticipated experience in the test year.

The PFD's recommendation to adopt the AG's proposed calculation of VEBA expense fails to address that the level of true ups in the most recent years has been impacted by the unusually high level of forfeitures due to the transition of the economy out of the COVID-19 pandemic, as well as the excess true ups recognized in 2024 attributable to lag hiring. As reflected on Exhibit A-36, Schedule AA3, the annual level of forfeitures for the years 2016 through 2021 averaged \$467,000, whereas in 2022 and 2023, the average annual forfeitures surged to \$2.614 million. This surge reflects the transitional impact of a once in a century pandemic and, thus, is unrepresentative of a normal level of forfeitures (Cooper, 3T 1563). The AG's claim that the most recent experience is a superior indicator of future forfeitures, and thus true ups, disregards that the impact of the pandemic is temporary and makes this most recent experience abnormal and demonstrably anomalous. The PFD also fails to address witness Cooper's rebuttal testimony that AG witness Coppola improperly used the years 2020-2024, which represents "too short of a period, because it excludes the increase in the Company's 2019 New Hire VEBA costs." (Cooper, 3T 1560).

The Company also takes exception to the PFD's adoption of the AG's annual escalation rate of 1.5% seemingly because the Company failed to explain why the AG's exclusion of 2019 from the AG's calculation was inappropriate and why the AG's use of a compound annual growth rate was inconsistent with traditional Commission practice (PFD, p. 484). However, the Company did just that. AG witness Coppola's sole justification for the 1.5% annual escalation rate is a footnote in his testimony that starts with New Hire VEBA costs of \$9.7 million in 2020 and \$10.3 million in 2024, which represents a compound annual growth rate of 1.5% (Coppola, 4T 3548). As described by Company witness Cooper, the use of only the New Hire VEBA costs for the years 2020 and -2024 is flawed because it fails to include the actual increase in costs between 2019 and 2020, which increased from \$8.965 million to \$9.716 million, or an increase of 8.4% (Cooper 3T

1560, Exhibit A-36, Schedule AA-4). Moreover, AG witness Coppola utilizes a compound average growth rate of 1.5%, in contrast with the Commission's long standing practice of using a five-year average of the actual percentage change in historical costs. The use of historical annual average increases was most recently confirmed in its Order in Case No. U-21534 in which it adopted the Average Annual Growth Rate (AAGR) for Active Healthcare expense (Case No. U-21534, Order dated January 23, 2025, p. 258). Further, the use of an average of annual percentage changes is the basis of Staff witness Rueckert's annual escalations used in this case (Rueckert, 5T 5194).

Because AG witness Coppola failed to properly normalize the 2024 New Hire VEBA costs and used an unreasonable annual escalation rate, the Company takes exception to the PFD's recommendation to adopt his proposed adjustments to New Hire VEBA expense. Accordingly, the PFD's proposed \$1.8 million disallowance of VEBA expense should be rejected and the Commission should adopt the Company's proposed New Hire VEBA expense calculation.

b. Employee Incentive Compensation Costs

DTE Electric witness Fix addresses the Company's incentive compensation programs, including the Company's request to recover the \$56.369 million net projected test period incentive compensation expense. As explained by witness Fix, this requested amount excludes the incentive compensation expense allocated to the Company for DTE Energy's top five executive officers (Fix, 3T 1482; PFD, p 494).

The Company takes exception to the PFD's recommended 100% disallowance of \$7.730 million of LTIP program Restricted Stock expense, as proposed by Staff. (PFD, pp 518-519). The PFD relies on the Commission's prior determination in Case No. U-21534 to disallow restricted stock payouts and "finds that DTE has not presented new evidence or argument that would necessitate a reversal from the Commission's prior determination regarding restricted stock."

(PFD, p 519). DTE Electric disagrees. In the Commission’s January 23, 2025 Order in Case No. U-21534, the Commission adopted Staff’s proposal to disallow recovery of Restricted Stock expense as “supported by the record as well as precedent,” finding that payout for the LTIP restricted stock program was “. . . based on DTE Energy stock prices and . . . awarded for achieving financial performance goals.” In contrast to the record in Case No. U-21534, there is substantial evidence in this proceeding that Restricted Stock is not tied to financial performance and is similar to other non-financial components of the Company’s incentive compensation program. The payout amount is not tied to the financial performance of the Company, instead, Company witness Fix explains:

. . . the Company’s Restricted Stock expense is completely *unrelated* to the Company’s financial results, and therefore, should not be regarded as a financial measure. Moreover, while Restricted Stock grants are in shares of DTE Energy Common Stock, the cost to the Company is recognized at the value of those shares on the date of grant, and therefore, are not variable based on the future price of DTE Energy’s Common Stock. Indeed, the cost recognized by the Company for the Restricted Stock upon grant *is the same as if the Company had made a promise to pay cash*. The mere fact the Restricted Stock grants are convertible into DTE Energy’s Common Stock does not make it a financial measure. Last, the benefits of Restricted Stock relate to the Company’s ability to attract and retain highly qualified employees, for which both customers and shareholders benefit. Accordingly, because the Commission’s exclusion of the Restricted Stock expense is based on this misunderstanding, it would be *unreasonable* to not include the Restricted Stock expense in the revenue requirement adopted by the Commission in this proceeding. (Fix, 3T 1496-1497; emphasis added)

Witness Fix also explains that Staff is necessarily relying on a different rationale in this proceeding than in Case No. U-21534, explaining that Staff Witness McMillan-Sepkoski inferred that Restricted Stock was a financial measure in her testimony in Case No. U-21534 because the Company’s employee handbook at the time stated that Restricted Stock was a reward for assisting

the Company in reaching its financial performance goals. However, in this case, Staff witness McMillan-Sepkoski cites an employee handbook that describes Restricted Stock as a reward to employees for supporting the Company's business objectives and long-term success. (Fix, 3T 1518). Witness Fix explains that achieving the Company's "business objectives and long-term success" refers to all aspects of the Company's operations, not exclusively financial. Notwithstanding the Company's position that Restricted Stock is dissimilar to other types of incentive compensation tied to financial performance, witness Fix and the Company in briefing acknowledge the Commission's prior determination in Case No. U-21534 and observe that the Company's AIP and REP measures are the best summary of the Company's business objectives, without any reference to financial performance. (Fix, 3T 1518). Therefore, the proposed disallowance in the PFD is not reasonable in light of the record and the Company takes exception.

Alternatively, and recognizing that the AIP and REP measures reflect a 40% weighting for financial measures and 60% weighting for operating measures (Fix, 3T 1519), the Company proposed that if the Commission is not inclined to modify its approach adopted in Case No. U-21534, the Company alternatively proposes to accept disallowance of 40% of the Restricted Stock expense, consistent with the 40% weighting of financial measures within AIP and REP, as a reasonable alternative to the complete elimination of the Company's Restricted Stock expense. This approach reduces the PFD's recommended disallowance of Restricted Stock by \$4.638 million. (DTE Electric's Initial Brief, p 191; DTE Electric's Reply Brief, p 183).

VIII. OTHER REVENUE-RELATED ITEMS

A. Infrastructure Recovery Mechanism

The Company's IRM was first approved in Case No. U-21297. The January 23, 2025 Order in Case No. U-21534 approved a partial extension of the previously approved 2025 IRM

investment levels and extended the Company's use of the IRM through calendar year 2026. In this proceeding, the Company presented two alternative proposals to extend the IRM. The first and primary proposal extends the IRM through calendar year 2029 and includes new investment authorizations for the Pole and Pole Top Maintenance & Modernization (PTMM) and System Cable programs through 2027, 2028, and 2029. (DTE Electric's Initial Brief, p 197). The second proposal expands the already-approved 2026 IRM to include the full amount of PTMM, Subtransmission Redesign and Rebuild (SRR), and Distribution Automation (DA) requested in this proceeding. (DTE Electric's Initial Brief, p 197).

Staff agreed with the Company's proposed extension of the IRM through 2027-2029. (Staff's Initial Brief, pp 202-206). With respect to the specific amounts for which the Company seeks permission to recover through the IRM, Staff recommended: 1) for Subtransmission Redesign and Rebuild, 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) for the Breaker replacement, URD replacement, and System Cable, Staff supports the amounts proposed; 3) for Distribution Automation, Staff supports 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; and 4) adding \$200 million for PTMM to the IRM. (Staff Initial Brief, pp 203-204). The Company accepted Staff's recommendations as to adjusted amounts to be recovered through the IRM for 2027-2029 and with respect to PTMM in 2026, as shown on Table 1 on page 200 of DTE Electric's Initial Brief. (See also, DTE Electric's Reply Brief, pp 188-190).

The PFD recommends that the Commission only approve a one-year extension of the IRM to 2027, with funding levels limited to the Company’s “alternative proposed programs and amounts, modified[,]” as reflected in the following table. (PFD, pp 557-558).

Program	2026	2027
Breaker Replacement	\$12.6 million	\$15 million
SRR	\$53.8 million	0
URD Replacement	\$13.5 million	\$15 million
Small Wires	\$10 million	\$10 million
Distribution Automation	\$24.4 million	0
PTMM	\$197.4 million	\$200 million
Total	\$311.7 million	\$240 million

The Company disagrees with the PFD’s recommendations for IRM approval. As an initial matter, the PFD does not reflect any System Cable investment in the table replicated above. (PFD, p 558). Given that no party in the case specifically contested the inclusion of System Cable in the IRM and the PFD does not offer discussion or findings regarding its exclusion, the Commission should include System Cable in the IRM.

The Company also disagrees with the recommendation of the PFD to approve a further reduced 2027 IRM relative to the Company and Staff proposals. The PFD indicates that its removal of SSR and DA is predicated on the need for “further analysis, as noted by Staff witness Evans, MNAG witness Stephens, and CEO witness Volkman, and acknowledged by the Company.” (PFD, p 557). The Company highlights that both Staff and the Company are supportive of DA (DTE Electric’s Initial Brief, pp 46-50 and 198-200; DTE Electric’s Reply Brief, pp 188-189; Staff’s Initial Brief, pp 203-204) and that any belief in further analysis did not preclude such support - tying a blanket removal of these programs to the Company’s and Staff’s position is inconsistent with the record in the case. The only additional basis in the PFD regarding the proposed exclusion of SSR and DA is that the programs “raised significant concerns about both the level and

effectiveness of proposed spending” (PFD, p 558) without any discussion linking the positions of the parties, or the merits of their positions, to the proposed disallowance. The Commission should reject the PFD and approve SSR and DA in the IRM.

The PFD also notes with respect to SSR and DA that the programs should remain in base rates in the test year. Given the PFD’s inclusion of these two programs in the 2026 IRM (the rate case test year), the Company is unclear as to what specifically the PFD is proposing. The Company clarifies that these programs should remain within the IRM in 2026, and in the case of DA, should include the additional 2026 automation investment recommended by the Company. (DTE Electric’s Initial Brief, p 201)

The PFD proposed to eliminate the IRM entirely beyond 2027. The PFD reasons that “extension of the IRM [into 2028 and 2029] could lead to inefficient spending if investment levels are locked in years before those investments are made.” (PFD, p 558). However, the PFD goes on to acknowledge that “substantial overall future investments will be necessary to improve the reliability and safety” of the system. (PFD, pp 558-559). As the PFD describes, the record in the case clearly supports the need for system investment. The PFD’s cure for its concern of inefficient spending is twofold. The first is to eliminate the IRM beyond 2027, which would appear at odds with the PFD’s observed need for system investment. As supported by the record evidence, DTE Electric and Staff are aligned with the Company’s proposed extension of the IRM through 2027-2029 subject to Staff’s recommendations as to adjusted amounts to be recovered through the IRM for 2027-2029. (Staff’s Initial Brief, pp 202-206; DTE Electric’s Initial Brief, p 200; DTE Electric’s Reply Brief, p 188-190). Thus, the Commission should reject the PFD and approve the IRM for 2028 and 2029.

The PFD also recommends adoption of CEO's proposed "effectiveness review" of IRM programs in future reconciliation proceedings to analyze whether the Company is realizing reliability outcomes from authorized spending. (PFD, p 559 citing 4T 3669-3670). The Company disagrees with the recommendation and the PFD's underlying conclusions.

First, on December 18, 2025, the Commission issued an Order Approving Settlement Agreement in Case No. U-21909 that established financial incentives and disincentives for reliability performance that are consistent with the Commission's Order in Case No. U-21400 dated February 27, 2025. DTE Electric's performance-based ratemaking (PBR) mechanism approved in Case No. U-21909 was the result of more than two years of workgroups, public comment, and a contested case proceeding among the Company, Commission Staff, and stakeholders. Importantly, the Commission has indicated the development and establishment of the Company's PBR mechanism is interrelated to the IRM. (Case No. U-21297 Order dated December 1, 2023, p 289; Case No. U-21534 Order dated January 23, 2025, pp 301-302). Indeed, the approved PBR mechanism and terms of the Case No. U-21909 Settlement Agreement comprehensively address, among other things, concerns relating to the effectiveness of IRM programs. (DTE Electric's Initial Brief, p 205).

The Case No. U-21909 Settlement Agreement not only established metrics, targets, thresholds, and maximums used to determine incentives or penalties that are consistent with the Commission's February 27, 2025 Order in Case No. U-21400, it also established an annual review process for the actual performance data from the prior year for each metric in the PBR mechanism, as well as the applicable targets and thresholds. (Case No. U-21909 Order dated December 18, 2025, pp 39-42). Hence, the Commission has approved a comprehensive and effective approach to ensure the success of DTE Electric's investments through a PBR mechanism that applies across

the totality of the Company's investments and reliability efforts. It is therefore neither reasonable or necessary to impose a bifurcated "effectiveness review" of IRM programs to analyze reliability outcomes, as requested by CEO and recommended by the PFD. (Willis, 4T 1772-1773).

Second, it must be kept in perspective that the forum for determining the effectiveness of IRM programs and the reasonableness of including proposed programs within the IRM remains the Company's general rate cases, such as the instant case. When first approving the Company's IRM in Case No. U-21297, the Commission established a clearly delineated process in which (1) proposed programs and investment levels are thoroughly reviewed at a programmatic level in general rate cases to determine reasonable and prudent costs for inclusion in the IRM; (2) the Company files annual IRM Plans with accompanying reviews and forums to provide Staff and intervening parties an opportunity to raise questions, provide feedback, and collaborate with the Company; and (3) annual IRM reconciliations are held as contested case proceedings to provide even greater transparency and opportunity for review of the Company's IRM expenditures. (Case No. U-21297 Order dated December 1, 2023, pp 289-291).

Regarding step (1) of the IRM ratemaking process that is conducted in general rate cases, as referenced above, the Company has robustly developed the record in this proceeding in support of its proposed IRM programs and investment levels. The Company applies substantial and expanding benefit cost analyses in support of proposed investments, both those in rate base and the IRM, and appropriately does so on a prospective basis. Once approved in a general rate case, the Commission has determined the reasonableness and prudence of the inclusion of the applicable programs and associated investment levels within the IRM. In direct reliance on the Commission's IRM approvals in general rate cases, the Company plans and implements its annual IRM Plans subject to reconciliations. If the PFD's recommended "effectiveness review" is adopted it would

render a clearly delineated IRM review and approval process too unpredictable for the Company to rely upon because it could result in disallowances of previously approved and invested dollars based on a redundant and unnecessary effectiveness review. . In order for the Company to execute approved IRM programs and expenditures arising from general rate cases, the PFD's recommended "effectiveness review" would compromise the requisite investment certainty needed to plan and implement the multi-year IRM. By compromising the requisite investment certainty, all other customer benefits afforded by the IRM also would be compromised, including increased accountability, review and input, and transparency. (Willis, 4T 1738-1739).

The Company maintains the position that "[u]sing the reconciliation process to monitor and potentially disallow recovery of costs for projects previously approved by the Commission would constitute retroactive ratemaking ... and is an improper use of the reconciliation process". (DTE Electric's Initial Brief, p 205). With respect to retroactive ratemaking, while the PFD addresses its view that "shifting funding in *future* IRM years, *prospectively*" is not retroactive ratemaking (emphasis original) (PFD, p 559), it is definitionally retroactive to disallow already approved and invested capital in a reconciliation based on a retroactive determination regarding the effectiveness of IRM programs already deemed effective in a general rate case . This is precisely what the CEO proposes and the PFD recommends. The time for determining effectiveness is in this general rate case, and the Company has done so. In addition to retroactive ratemaking concerns, at a minimum, the "effectiveness review" is an improper use of the IRM reconciliation process that runs afoul of Commission-approved IRM approval and review processes that would compromise the numerous customer benefits derived from the IRM. Based on the foregoing, the Commission should reject the PFD's proposal for an unreasonable and unnecessary effectiveness review in the IRM reconciliation process.

B. Pilot Programs

1. Strategic Undergrounding Pilots

The Company presented two undergrounding pilot programs for approval in this proceeding: (1) Spruce, an undergrounding suburban project in coordination with the City of Ann Arbor; and (2) Attica, a project being developed in a rural area. (Stowe, 2T 229).

The PFD recommends acceptance of costs with the Attica project, leaving only the Spruce project at issue. (PFD, p 567). The PFD proposes a disallowance of \$11.6 million for the Spruce project because the BCA indicates that its “costs meaningfully exceed the benefits it will produce.” (PFD, p 567). The Company disagrees with the PFD’s recommendation related to Spruce for the following reasons.

Undergrounding is the only investment option that fully eliminates the safety risk associated with downed wires and structures. (Stowe, 2T 230). It also provides the highest overall benefit in reducing emergent reactive costs and customer outages and is the most resilient option for severe weather-related events. (Stowe, 2T 230).

As noted by the PFD, the Commission has directed the Company to investigate targeted, strategic undergrounding projects where there is a business case to do so. (PFD, p 567). The BCA conducted by Company witness De Stigter shows that, while costs of the Spruce project exceed anticipated benefits, it will still provide millions of dollars in benefits to customers. (De Stigter, 4T 1858). Despite the estimated benefits-to-cost ratio, this pilot is a unique opportunity to learn from municipal infrastructure coordination with strategic undergrounding in an area that the Company was already going to rebuild as part of the ISO Conversion Program. (Stowe, 2T 233). Moreover, the Spruce pilot project is coordinated with the City of Ann Arbor’s plan to replace roads in the area, which gives the Company a unique opportunity to avoid the costs associated with

breaking down and restoring roadways. (Stowe, 2T 162-163). The Company has followed the Commission's guidance, and the Commission should accept capital expenditures associated with the Spruce project, notwithstanding the PFD's recommendation.

C. Affordability

Certain intervenors in the proceeding raised challenges related to a rate increase on residential customers, as well as DTE Electric's assistance programs for low-income customers to maintain access to electric service and afford their energy bills. The PFD categorized those challenges as relating to: (1) affordability and energy burdens; (2) low-income energy assistance programs; (3) unregulated programs; and (4) shutoffs. (PFD, p 569). Each of these topics is addressed in turn below.

1. Energy Burden and Affordability

CUB-NRDC, CEO, and the DAAO asserted that DTE Electric's proposed rate increase for residential customers should be rejected due to "energy burden" considerations and lack of customer affordability for lower income customers. (PFD, pp 569-581 (summarizing arguments by CUB-NRDC, CEO, and the DAAO)). DTE Electric maintained that its requested rate increase results in average residential rates below the average increases of other utilities in the Great Lakes region and at the national level. (PFD, p 577 (citing DTE Electric's Initial Brief, p 5)). While Staff addressed the affordability arguments raised by intervenors more generally, it recognized that "there is no state or federal, constitutional statutory guarantee for free or fixed rate utility services for those that cannot afford to pay." (Staff Reply Brief, p 18). The PFD ultimately agreed with Staff "that the Commission must follow statutory and other legal directives when setting rates" and declined to adopt the recommendation that DTE Electric's residential rate increase be denied. (PFD, p 580).

The PFD, however, acknowledges and agrees with the affordability concerns raised by certain intervenors and presents the Commission two related recommendations. First, the PFD found CUB-NRDC and the DAAO's arguments that energy burden is a better comparison for customer affordability persuasive, recommending that the Commission require DTE Electric to "present data about its residential rates and the impact of its requested rate increases on residential customers by providing data on the electricity burdens of its residential customers" and to do so "in all rate cases going forward." (PFD, p 580). As to this recommendation, the Company respectfully disagrees and asserts that presentation of energy burden data as described by CUB-NRDC and DAAO is not industry standard and would introduce costs and administrative burden beyond the regulated electric service that DTE Electric provides to its customers. The Company also takes exception to the PFD's seeming determination of what constitutes an "unaffordable electric burden" equating to "electric bills constituting more than 4% to 6% of their household income . . ." and notes that the Commission gave clear direction in its January 2023, 2025 Order in Case No. U-21354 that "the Commission expects DTE Electric to use the Commission-adopted definition of 'affordability' for any analyses it presents to the Commission when referencing affordability impacts of energy-assistance programs in contested cases." Case No. U-21534 Order dated January 23, 2025, p 461). The Company also does not agree that it is procedurally appropriate for the Commission to establish new electric rate case filing requirements applicable to "all rate cases going forward" in this case and further agrees with Staff that the Commission has established the EAAC (Energy Affordability and Accessibility Collaborative) as well as other collaboratives to consider such issues and "a rate case, such as this, is not the appropriate place to discuss such proposals." (Staff Reply Brief, p 17). The Commission concluded an update to the

Michigan rate case filing requirements in Case No. U-18238 in 2024 and this is not the forum to reopen or amend the determinations in that proceeding.

Second, the PFD recognized that Staff’s Energy Affordability Report addressed concerns about affordability and the need for immediate relief, as recognized by the Commission in DTE Electric’s last rate case, Case No. U-21534. (PFD, pp 580-81). The PFD was persuaded, however, by the DAAO’s comments on the impact of rate increases on low-income customers being intensified by poor insulation, less energy efficient appliances, and decreased access to smart technology. Accordingly, the PFD also recommends that DTE Electric be directed to implement an initiative “to educate all low-income customers about, and assist them with, accessing programs or funding for weatherization, EWR, and energy efficiency.” (PFD, p 581). The PFD’s recommendation that DTE Electric “be directed to implement an initiative” (PFD, p. 581) to educate all low-income customers is unnecessary because DTE Electric already operates a comprehensive initiative that includes annual system-wide assistance notifications, agency-partnered Community Resource Fairs with onsite application support, Income-Qualified EWR programs delivering weatherization-aligned measures, employee ambassador training for proactive customer assistance, and data-driven outreach targeting households with the highest energy burdens.(4T, 1785, 2716-2722).As such, the initiative recommended by the PFD would be duplicative, and the Company respectfully requests that the Commission reject the PFD’s position.

2. Low-Income Assistance Programs

In discussing DTE Electric’s current low-income assistance programs and the intervenors’ “many specific recommendations,” the PFD states that it is “in agreement with Staff” and recommends the Commission review the Energy Affordability Report and provide guidance on appropriate next steps by February 2026. (PFD, pp 594-95). Specific to DTE Electric, the PFD

recommends DTE Electric “use electric burden as its key indicator of affordability in its analysis of low-income programs.” (PFD, p 595). The PFD notes that Staff’s Energy Affordability Report makes recommendations for a redesigned energy assistance system with energy assistance subsidies based on customers facing an energy burden of 6% and electric burden of 4% of their monthly income. (PFD, p 594). As seemingly recognized by the PFD, issues like these should be addressed by the Commission and the EAAC (Energy Affordability and Accessibility Collaborative) in Case No. U-20757. Accordingly, the Company disagrees with the recommendation.

3. Unregulated Programs

The PFD reviews DAAOs testimony on DTE Electric’s unregulated program offerings to customers and notes DAAOs acknowledgment that the Commission cannot regulate these programs. (PFD, p 597). The PFD further notes that “no other party presented evidence or commented on the Company’s unregulated programs” but then proceeds to recommend the Commission task the EAAC (Energy Affordability and Accessibility Collaborative) EAAC with “investigating the impact of DTE’s unregulated programs on affordability and shutoffs, to include disparities in marketing and enrollment, and make recommendations to the Commission on ways to mitigate these impacts.” (PFD, p 598) DTE Electric takes exception to this recommendation as it purports to do what the PFD found the Commission cannot do, which is to regulate the unregulated programs. Additionally, the unregulated programs offered by the Company are wholly separate from the rates it charges for regulated electric service. They are discretionary programs that are made available to customers, similar to any other discretionary product or service that customers may choose to purchase. “Affordability” with respect to utility rates is wholly distinct

from consumer spending on discretionary products and services and, therefore, the Commission should reject the PFD's recommendation on this issue.

4. Shutoffs

The PFD makes several recommendations in response to intervenor testimony about an increasing number of shutoffs and the corresponding costs, and based on the PFD's conclusion that it would be "prudent to analyze shutoffs more thoroughly." (PFD, pp 598-611). First, the PFD recommends that the Commission direct DTE Electric to:

gather, review, and analyze its customer account data to determine the following: how many customers whose electricity is shut off for nonpayment have their service restored and the average time it takes for restoration; whether the duration of the average shut-off is increasing; whether and to what extent shut-off duration correlates with arrearage balances; and any other factor that may reveal why disconnections are increasing and how to reduce them. (PFD p. 609)

While the Company acknowledges the impact of shutoffs for nonpayment on its customers and the importance of reviewing and assessing customer shutoffs, it echoes Staff's sentiments that this rate case is not the appropriate forum to address shutoffs and related issues. (Staff Reply Brief, p 16-17).

The PFD also provides that "DTE should review its disconnection policies and use regression analysis to determine if customers are disconnected disparately based on race, income, or geography and report shutoff data at the census tract level." (PFD, p 610). As noted by Company witness Sparks, the Company's disconnection policies are applied uniformly, and shutoff decisions are based solely on account status and payment history. (Sparks, 4T 2743). There is no evidence suggesting systemic disparities in disconnection practices based on demographics or regional factors. (Sparks, 4T 2743). Moreover, witness Sparks notes a number of factors, such as data privacy and system compatibility, that make collecting shutoff data at the census tract level impracticable and unnecessary. (Sparks, 4T 2744). As a result, the Company maintains that the

recommended regression study is not necessary, would be overly burdensome, and therefore, should be rejected.

The PFD also recommends requiring DTE Electric to expand and accelerate its shutoff analysis beyond the timing established in Case No. U-21534, and the Company respectfully disagrees. In that case, the Commission intentionally determined that shutoff and arrearage trends should be evaluated through existing reporting and policy proceedings rather than through accelerated analysis in a general rate case, and any changes to that framework should be considered in the appropriate policy forum rather than here.

Finally, the PFD includes recommendations responding to intervenor testimony on DTE Electric's medical and critical care programs. Many of the recommendations are directed to the EAAC; though, in one instance the PFD recommends DTE Electric "publish its internal guidance for eligible conditions, affirmatively reach out to medical providers, and provide fulsome and timely explanations and an appeal process to customers denied entrance into the programs." (PFD, pp 610-611). As seemingly recognized by the PFD, issues like these should be addressed by the Commission and the EAAC in Case No. U-20757, not here. Accordingly, the Company disagrees with the recommendation and respectfully requests that the Commission reject the shutoff recommendations directed at DTE Electric in this proceeding.

D. Environmental Justice

DTE Electric witness Kryscynski explained how the Company uses environmental justice (EJ) considerations in its distribution grid planning. First, witness Kryscynski explained that DTE Electric uses an MiEJScreen Tool to identify vulnerable communities, which was "developed with extensive input from Michigan stakeholders, including experts in the EJ community, is maintained by the State of Michigan, and includes a breadth of socioeconomic and environmental factors in

its EJ impact scoring that the Company does not maintain and does not have the expertise to compile.” (Kryscynski, 3T 1292). The Company’s use of this tool follows the Commission’s recognition of MiEJScreen “as the primary screening criteria in assessing EJ impacts associated with planned company investments.” (Case No. U-21534 Order dated January 23, 2025, p 124).

After identifying vulnerable communities, DTE Electric applies an EJ multiplier in its Grid Prioritization Model (GPM) to increase benefit cost ratios for projects benefiting vulnerable census tract communities, which results in a higher likelihood that those projects will be selected for funding. (Kryscynski, 3T 1201-1204). The Company also uses the EJ multiplier for prioritizing circuits within the PTMM and Automation Programs and intends to use the EJ Multiplier for its IRM Plans going forward. (Kryscynski, 3T 1243-1244). Together, DTE Electric’s EJ analysis and use of the MiEJScreen Tool provide a robust and comprehensive basis for prioritizing investments in EJ communities.

Nevertheless, the PFD found the Company’s extensive EJ analysis lacking and recommended additional EJ analysis in future rate case and Distribution System Planning (DSP) proceedings. (PFD, 621-622). The Company disagrees with the PFD’s recommendations.

The PFD takes issue with the Company’s inability to present its analysis on changing demographics as directed by the Commission’s Final Order in Case No. U-21534 until its 2026 Distribution System Planning (DSP) filing. (PFD, p 621).⁴⁰ As noted in the rebuttal testimony of Company Witness Kryscynski, the Commission-directed analysis is complex with numerous variables and data limitations that require stakeholder engagement. (Kryscynski, 3T 1293).

⁴⁰ The Commission’s Order in Case No. U-21534 dated January 23, 2025 recommended that DTE Electric “evaluate changing demographics over time using data consistent with the underlying data sets for the detailed regression analysis already required to investigate ‘customer demographics and reliability for vulnerable communities to be used in the company’s distribution plan case’” (Case No. U-21534 Order dated January 23, 2025, p 124).

Performing this type of study in the three months prior to filing the instant case was simply not practicable. Moreover, the Order in Case No. U-21534 dated January 23, 2025 did not explicitly require the Company to submit the recommended changing demographics analysis in its next rate case. The Company reiterates its intent to present the Commission-directed analysis in its 2026 DSP.

The PFD also recommends additional studies to the Company's existing EJ analysis. First, the PFD recommends that the Company run a regression analysis in all its rate cases and DSPs. (PFD, pp 621-622). First, it is unclear what role the regression analysis will have in distribution planning in the future. Second, the findings of a regression study relating to EJ considerations in distribution planning are more appropriate for a DSP proceeding than it is a rate case. For that reason, the Company already intends to include a regression analysis in its 2026 DSP filing. Thus, it would be both lacking in relevance and unnecessarily duplicative to require the same analysis in a future rate case as well.

The PFD also recommends the Company "conduct an analysis comparing service reliability in EJ census tracts to non-EJ census tracts with similar population densities and other characteristics, such as urban EJ to urban non-EJ," "include distributions, not just averages, across EJ gradations in its reliability reporting," and "pair the MiEJScreen Tool with reliability and energy-burden indicators so that investments increase reliability without worsening affordability." (PFD, pp 621-622). The regression analysis that the Company will provide in the DSP will include the census tract comparison and distributions recommended by the PFD. However, DTE Electric takes exception to the PFD recommendation to pair the MiEJScreen Tool with reliability and energy-burden indicators because there is no explanation as to how this additional study would benefit EJ communities or how these new indicators do or do not overlap with factors already

contained within the MiEJScreen Tool. Again, the Company is already using the Commission’s “primary screening criteria” for identifying and prioritizing vulnerable communities. (Case No. U-21534 Order dated January 23, 2025, p 124). Moreover, the objective of the recommendation is unclear. When prioritizing reliability improvements, the Company utilizes the GPM which already considers EJ. If an investment is made in an EJ community, the rates associated with that investment are applied to all customers in the service territory and not to the specific community.

As part of this recommendation, the PFD further notes the Commission should require the Company to “better account for the number of residential customers on a given circuit rather than just the proportion of customers living in an EJ community, if possible, when prioritizing EJ in its GPM model, incorporate EJ into its Reliability Model, and build EJ considerations into the CE and SRIP programs to further target disadvantaged communities.” (PFD, p 622). The Company takes exception to this recommendation, because again there is no explanation as to how it will benefit EJ communities. Again, the Company is already using the Commission’s “primary screening criteria” for identifying and prioritizing vulnerable communities. (Case No. U-21534 Order dated January 23, 2025, p 124). As explained by Company witness Kryscynski, the Company’s existing distribution planning already incorporates significant EJ analysis and considerations. (Kryscynski, 3T 1221-1244; 1290-1295). Additionally, the PFD appears to mistakenly assume that the Company’s GPM does not account for number of residential customers per circuit. However, the GPM analyzes projects, typically at a circuit level, and creates the EJ multiplier by accounting for the total number of residential customers on that circuit, determining which of them fall into EJ census tracts, and which do not. (Kryscynski, 3T 1202-1203; 1224) The Company’s Reliability Model is used to project future reliability; therefore, adding EJ designations in this model does not provide additional benefits (Kryscynski, 3T 1213). The Company recognizes that EJ data, tools,

and analysis are evolving and will continue to analyze EJ trends while collaborating with stakeholders to develop plans for the 2026 Distribution System Plan. However, the Company takes exception to the PFD's recommendations to further expand DTE Electric's EJ analyses without a stated need or purpose for additional analysis.

E. Accounting Requests

The PFD presents recommendations on certain of the Companies' accounting requests at page 622, but also does not appear to address all of the Company's requests for regulatory accounting authorizations in the PFD. For completeness and consistency, DTE Electric addresses all accounting requests presented by the Company in this section.

The PFD finds that the Monroe regulatory asset revenue requirement be calculated based on the decisions in the Commission's final order. (PFD, p 622). Regulatory asset treatment for certain Monroe Power Plant assets was approved by the Commission in Case No. U-21193. Company witness Uzenski provides details regarding the calculation of the Monroe Regulatory Asset balance. (Uzenski, 4T 2467-2469; DTE Electric's Initial Brief, p 243). Staff's Initial Brief, pp 176-177, recommends that the return on the Monroe Regulatory Asset revenue requirement be based on Staff's recommended 6.52% projected pre-tax cost of capital rather than the Company's projected pre-tax cost of capital of 6.58%, resulting in a return of approximately \$139 million rather than \$141 million. (Nichols, 5T 4880; DTE Electric's Reply Brief, p 215). Staff's reply brief did not discuss this topic but continued to apply Staff's recommended 6.52% pre-tax cost of capital. (Staff's Reply Brief, Appendix A1.2). For the reasons discussed in Section VI, which addresses DTE Electric's Cost of Capital, the Commission should approve the Company's recommended overall pre-tax cost of capital of 6.58%, which will appropriately flow through to the return on the Monroe Regulatory Asset revenue requirement.

The PFD also recommends that the Commission approve the Company's proposed regulatory liability treatment for O&M expense at its Midwest Energy Resources Company (MERC) recovered in rates that exceed the amount incurred until rates are reset in a future rate case, because such treatment can protect ratepayers from potential over-recovery. (PFD, p 398). The Company supports the PFD's recommendation. As discussed in the Company's briefing, the Company expects to incur operating costs at MERC through mid-2026, and the Company's O&M forecast reflects a reduction based on that assumption. Given the planned operating timeline for MERC, the Company requests the regulatory liability treatment. (Uzenski, 4T 2486; Milo, 3T 735-736; DTE Electric's Initial Brief, p 243; DTE Electric's Reply Brief, p 216). Staff supports the requested treatment. (McMillan-Sepkoski, 5T 4986). Based on the foregoing, the Commission should approve the Company's request for the benefit of customers.

In addition to the foregoing accounting requests addressed in the PFD, the PFD does not appear to address DTE Electric's requests summarized at pp 242-244 of the Company's Initial Brief and pp 215-218 of its Reply Brief to continue previously approved deferral accounting treatment and for new accounting authorizations related to (i) permission to record issuance costs (e.g., commitment fees, due diligence, legal) associated with securing debt financing of up to \$7.2 billion from the U.S. Department of Energy under the Inflation Reduction Act (IRA) to a regulatory asset for future recovery, if the Company does not reach financial close on this loan (Uzenski, 4T 2486-2487); (ii) to defer investment tax credits (ITC) that DTE Electric expects to earn under the IRA with respect to the Trenton Channel battery storage asset to a regulatory liability (Uzenski, 4T 2483); (iii) the Company also notified the Commission in response to its prior direction to defer certain outage credits in account 182.3, Other Regulatory Assets, that no such deferred costs are reflected in the instant case. If the cost becomes material, the Company will defer the expense and

request recovery in a future rate case. (Uzenski, 4T 2486). As addressed in the Company's Reply Brief, at 216-218, Staff did not oppose any of the foregoing requests or proposals, and the Company respectfully requests the Commission authorize the new or continuing regulatory accounting treatment, as requested in DTE Electric's Application and summarized in the Company's briefing.

IX. COST OF SERVICE

A. COSS Allocation Adjustments

1. Production Cost Allocator

Staff did not recommend changing the production allocator in this case, however, the PFD notes that Staff further advised the Company to run and present the standard coincident peak tests in its next rate case and to provide some insight into expected seasonal or monthly load growth, including commentary on the potential for changes to the production allocator based on seasonal load shifts. (PFD, pp.631- 632)

The PFD observes that the Company did not address this recommendation in its brief and recommends that the Commission either adopt Staff's recommendation or initiate a separate proceeding to address production cost allocation concerns under seasonal load shifts on an industry-wide basis. (PFD, pp. 632)

DTE Electric does not take issue with the Staff's recommendation, however, no party proposed a separate proceeding to address the Staff's recommendation. As such, the Commission should decline to create a separate proceeding.

X. RATE DESIGN AND TARIFF ISSUES

A. Residential Rate Design

1. Rate Schedule D1.6 Transition and Closure

In its Initial Brief, the Company explained that it agrees with the objective of protecting and assisting customers during the D1.6 to D1.11 rate transition and has already implemented a comprehensive outreach plan consistent with Commission direction. (DTE Electric’s Initial Brief, p 227).

DAAO argued that the Company has not complied with the Commission’s directives in Case No. U-21534 regarding the transition of customers from Rate D1.6 to Rate D1.11 and mitigation of potential adverse impacts for low-income customers. (DAAO Initial Brief, pp 79-89). DAAO contends that the Company did not provide an analysis of factors affecting low-income households’ ability to shift usage, relying instead on older Advanced Customer Pricing Pilot (ACPP) survey materials that allegedly do not examine causal constraints and show low-income customers may face greater barriers to shifting. (DAAO Initial Brief, pp 80–83). DAAO further asserted that the Company has not implemented Commission ordered safeguards to identify and address harmful energy limiting behavior using AMI data and urges that the D1.6 transition be paused until the Company presents a concrete assistance plan tailored to at risk low-income households. (DAAO Initial Brief, pp 84–89). DAAO also claimed the Company did not implement Commission ordered mitigation measures beyond “generic outreach,” particularly targeted weatherization and smart thermostat support, and asks the Commission to require post transition bill tracking for low income customers and to address nonmonetary TOU impacts on household wellbeing. CEO similarly recommends that the Commission require shadow billing of vulnerable

customers transitioning to D1.11, with targeted outreach to ensure that those customers do not experience bill increases. (DAAO Initial Brief, pp 79-89; CEO Initial Brief, pp 43-45).

The PFD adopts these concerns and recommends the Commission substantially expand the requirements associated with the D1.6–D1.11 transition. (PFD, pp 654-656). The PFD first notes that the Company has provided a regression analysis and some shutoff information but suggests that the Company “has not sufficiently analyzed the factors impacting low income customers’ ability to shift usage” and recommends that the Commission direct DTE Electric to “conduct an updated analysis specifically designed to analyze the factors impacting low income customers’ ability to shift usage” and provide that analysis as soon as feasible, but not later than the Company’s next rate case. (PFD, p 655). The Company takes exception to this recommendation. The Case No. U-21534 Order characterizes this requirement as “shall include...an analysis of the factors impacting household ability to shift usage”. (Case No. U-21534 Order dated January 23, 2025, p 394). The Case No. U-21534 Order did not direct the Company to create a new analysis, nor an analysis based on specifically transitioning customers. What the Company provided was an extensive discussion and contextualization of a robust analysis of behavioral factors and perspectives around energy usage (e.g. “ability to shift usage”) specific to low-income customers. (Gerdes, 4T 2527-2531; Willis, 4T 1781-1782; Exhibit DAO-6). It was conducted based on the ACPP, an extensive, costly, and statistically robust effort conducted over more than a year, involving more than ten thousand customers in support of a rate transition for approximately two million customers. The Company’s prior time-of-use rate transition also included approximately 95,000 low-income customers. Neither the prior time-of-use transition nor the now completed D1.6 transition has evidenced any structural concern or complaints from customers. (Willis, 4T 1781-1782, 1785). As such, the Commission should reject the PFD on this matter.

The PFD also agrees with CEO that the Company has “failed to describe a targeted plan to promote weatherization and smart thermostats,” but disagrees with DAAO’s suggestion that the directives in Case No. U-21534 require the Company to develop new substantive programs beyond educational outreach. (PFD, p 655). The PFD therefore recommends that the Commission order DTE Electric to “update and modify its educational outreach to transitioning low-income customers to ensure it includes substantive information about weatherization and smart meters.” (PFD, p 655). The Company takes exception to this recommendation. The Company complied with the Order, which did not direct the Company to “describe a targeted plan to promote weatherization and smart thermostats”. Instead, that Order directed the Company to implement “expanded educational outreach to low-income customers regarding low-income energy efficiency programs, weatherization, and smart thermostats” (PFD, p 655). The Company has completed the communications described in the record for the D1.6 transition that has since been completed, which includes information regarding the Company’s energy waste reduction programs (including weatherization programs and smart thermostats). (Willis, 4T 1780-1781). The Commission should reject the recommendation to further expand the communication requirements beyond the directives in U-21534.

The PFD finds that the Company “did not present a plan” to use AMI data to identify and address energy limiting behavior and that the Company’s explanation that it is developing an approach is “insufficient,” and it recommends additional AMI based analysis and outreach, including “shadow billing of vulnerable transitioning customers” as well as tracking and reporting of low-income bill changes after the transition. (PFD, pp 655-656). The Company takes exception to this recommendation. The Order in Case No. U-21534 directed the Company to use “smart meter data to identify customers and address energy-limiting behavior that is adverse to health and

safety” (Case No. U-21534 Order dated January 23, 2025, p 394). The Company described its plan to address this requirement on the record, including the approaches under consideration. (Willis, 4T 1780-1785, DTE Electric Reply Brief p. 207). The Company could not have already completed the outreach given that the transition was conducted in October 2025 and an analysis based on meter data requires the transition to have occurred and for there to be D1.11 data to analyze.

The PFD recommends “the Commission require DTE identify and assist low-income customers during the D1.6 to D1.11 transition” with outreach including “AMI-based analytics to flag at-risk households; targeted, multilingual outreach; streamlined enrollment in assistance (e.g., LIA/arrears management); and practical mitigations (e.g., smart thermostat support, weatherization referrals, safety checks, and near term bill protection where warranted)” (PFD, pp 655-656). The transition was completed in October 2025, and the Company is unaware of associated concerns from transitioned customers. Moreover, the Company sent extensive materials to *all* customers transitioning (not just those deemed “at risk”). The customers being transitioned are by definition already enrolled and receiving the LIA credit (a requirement of the former D1.6) and were provided extensive “practical mitigation” information via the welcome kits sent to customers. (Willis, 4T 1781-1785). The Commission should reject this recommendation.

The PFD further recommends “that the Commission require DTE to discuss the transition and its mitigation measures in its next rate case, including conducting shadow billing of vulnerable transitioning customers and targeted outreach to those customers to address bill impacts. The PFD also recommends the Commission should also require that DTE track low-income customer bills after the transition and report this data in its next rate case in such a form that it will permit analysis of how many low-income customers experienced decreased and increased bills and by how much.” (PFD, p. 656). Taken as a whole, it is not evident what purpose these recommendations serve given

that the transition is complete. Focusing on “shadow billing”, the Commission already approved the closure of Rate Schedule D1.6 in Case No. U-21534 (Order dated January 23, 2025, pp 393-394). Shadow billing is not possible to conduct given that the Company’s instant case does not include rates for Rate Schedule D1.6; there is no rate upon which to base a shadow bill. Moreover, it is not evident from the PFD or the record what would be tangibly accomplished by shadow billing even if it was possible to conduct. The recommendation for bill tracking and reporting is similarly unclear. The Company is unable to track actual bills relative to a hypothetical D1.6 bill – the rate has been closed and there is no D1.6 rate upon which to conduct such an assessment. The Company is again unclear what such tracking would tangibly accomplish given that D1.6 was closed by the Commission. (Willis, 4T 1779-1785, DTE Electric Reply Brief pp 207-208). As such, the Commission should reject the recommendations of the PFD on these topics.

Company witness Sparks analyzed shutoff information by comparing disconnection rates before and after the 2023 full TOU transition, and Company witness Willis explained that DTE Electric will complete the specific D1.6 shutoff analysis once a full year of post-transition data is available, or in the next rate case, so the results are meaningful. (Sparks, 4T 2732; Willis, 4T 1784-1785). Thus, the Company does not take exception to the PFD recommendation to complete the shutoff analysis by the next rate case.

The Commission should recognize that the Company has complied (or has demonstrated that it is continuing progress toward compliance) with the ordered analyses and mitigation requirements, as demonstrated in this record, and reject the PFD’s suggestion to reopen and expand those obligations beyond what the Commission previously directed in Case No. U-21534.

B. Commercial Secondary and Primary Rate Design

1. Rate D3 - EV Fast Charger Rate

Staff recommends that the Commission (i) remove the two-year rolling provision from the currently approved holiday and further recommended that the June 1, 2028 sunset date established in Case No U-21534 be firm for the demand charge holiday, and (ii) direct the Company in its next rate case to propose a new, cost-of-service-based fast-charging tariff that is an energy-only rate with no demand charges. (Staff’s Initial Brief, pp 195-196). MEIU witness Schuster, argues the Commission should not accelerate changes to DC fast-charging rates or end the two-year rolling demand-charge waiver. (MEIU’s Initial Brief, pp 18-22). Walmart witness Lyon recommends that the Commission “direct the Company to plan, develop, and announce a stakeholder convening agenda and schedule as soon as is prudent to allow for sufficient opportunity and time to develop a consensus-based EV fast charging rate proposal to present to the Commission no later than December 1, 2026.” (Walmart Initial Brief, p 9).

The PFD adopts Staff’s DCFC recommendations, finding them consistent with the DCFC tariff framework already established in Case No. U-21534, rejects MEIU’s suggestion to wait for “market stability” or steady-state usage before implementing a fast-charging tariff, and concludes that, because DTE Electric has acknowledged that many Staff and intervenor priorities are already embedded in the Case No. U-21534 Order, no additional Commission direction is needed beyond that Order. (PFD, p 667).

The Company agrees that any successor EV fast-charging rate should be grounded in cost-of-service principles and developed through the specific process the Commission already established in its January 23, 2025 Order in Case No. U-21534, but takes exception to the PFD to the extent it is pre-ordaining detailed design criteria such as an energy-only structure with no

demand charges. As explained in witness Willis's rebuttal testimony (Willis, 4T 1790-1791), and reiterated in the Company's Initial Brief (p 233) and Reply Brief (pp 209-210), such considerations will be vetted through a future stakeholder process. Additionally, the Company clarifies that the December 1, 2026 tariff filing date established by the Commission in Case No. U-21534 should be maintained (DTE Electric Reply Brief p 210). Subject to these clarifications, the Company agrees with the PFD that no additional direction is necessary from the Commission at this time.

XI. REQUEST FOR RELIEF

DTE Electric respectfully requests that the Commission issue its final order:

- A. Granting DTE Electric's request for final rate relief, as further supported and explained in its Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief (including Reply Brief Attachments A and B), and these Exceptions (including Exceptions Attachment A) approving rates that will recover the Company's revenue deficiency of approximately \$561.7 million, based on a January 1, 2026 through December 31, 2026 projected test year;
- B. Approving an annual revenue increase effective as soon as possible in the projected test year;
- C. Approving new rates effective as early as February 24, 2026, in the manner described in the Company's Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief (including Reply Brief Attachments A and B), and these Exceptions (including Exceptions Attachment A);
- D. Approving DTE Electric's proposed capital structure and return on equity;

- E. Granting DTE Electric's request to approve the PSCR base;
- F. Approving DTE Electric's proposals to implement certain customer rate schedules and tariffs;
- G. Approving recovery of DTE Electric's generation investments;
- H. Approving recovery of DTE Electric's investments related to the strengthening of the Company's distribution system and reliability improvements;
- I. Approving the extension and expansion of the IRM;
- J. Approving all requests to employ special accounting treatments as requested by the Company;
- K. Approving the capacity charge calculated by the Company, which is based on the methodology utilized in Case No. U-21534, and approving the capacity-related costs supported by the Company in this proceeding;
- L. Approving the remainder of DTE Electric's proposals and requested relief as set forth in the Company's Application, testimony, exhibits, Initial Brief, Reply Brief and these Exceptions; and
- M. Approving the remainder of DTE Electric's proposals and requested relief as set forth in the Company's Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief (including Reply Brief Attachments A and B), and these Exceptions (including Exceptions Attachment A); and

N. Granting such other lawful relief that the Commission deems reasonable and appropriate.

Respectfully submitted,

DTE ELECTRIC COMPANY
Legal Department

By: _____
Attorneys for DTE Electric Company
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Dated: January 9, 2026

DTE Electric Company
 Computation of Revenue Deficiency
 Projected 12 Month Period Ending December 31, 2026
 (\$000)

MPSC Case No. U-21860
 Exceptions to PFD
 Attachment A
 Page 1 of 4

Line No.	(a) Description	(b) Reply Brief Position	(c) Adjustments	(d) Exceptions to PFD Position	(e) ALJ Proposal for Decision	(f) Difference
1	Rate Base (1)	\$ 23,515,626	\$ -	\$ 23,515,626	\$ 23,035,019	\$ 480,607
2	Adjusted Net Operating Income (2)	1,118,401	-	1,118,401	1,249,412	(131,011)
3	Rate of Return (3)	6.0427%	0.0000%	6.0427%	5.6424%	0.4003%
4	Income Requirements	1,420,979	-	1,420,979	1,299,738	121,241
5	Income Deficiency (Sufficiency)	302,578	-	302,578	50,326	252,252
6	Revenue Conversion Factor (4)	<u>1.3496</u>	<u>-</u>	<u>1.3496</u>	<u>1.3496</u>	<u>-</u>
7	Rev Deficiency / (Sufficiency)	<u>\$ 408,369</u>	<u>\$ 0</u>	<u>\$ 408,369</u>	<u>\$ 67,921</u>	<u>\$ 340,448</u>
8	Tree Trim Surge (5)	11,944	-	11,944	4,854	7,090
9	Monroe Regulatory Asset (5)	<u>141,416</u>	<u>-</u>	<u>141,416</u>	<u>138,101</u>	<u>3,315</u>
10	Revenue Deficiency / (Sufficiency) - Total	<u>\$ 561,729</u>	<u>\$ 0</u>	<u>\$ 561,729</u>	<u>\$ 210,876</u>	<u>\$ 350,853</u>

Sources

- (1) Attachment A, Page 2
- (2) Attachment A, Page 3
- (3) Attachment A, Page 4
- (4) Exhibit A-13, Schedule C2
- (5) Exhibit A-11, Schedule A1

DTE Electric Company
Rate Base - Average Net Plant
For the 13-Month Average Period Ending Dec. 31, 2026
(\$000)

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description	Reply Brief Position	Adjustments	Exceptions to PFD Position	ALJ Proposal for Decision	Difference
1	Plant in Service	\$ 26,150,061	\$ -	\$ 26,150,061	\$ 25,642,875	\$ 507,186
2	Plant Held for Future Use	224		224	224	-
3	Construction Work in Progress	2,637,403	-	2,637,403	2,637,403	-
4	Acquisition Adjustments	77,542		77,542	77,542	-
5	Total Utility Plant	28,865,230	-	28,865,230	28,358,043	507,186
6						
7	Less: Depreciation Reserve	6,921,497	-	6,921,497	6,894,918	26,579
8						
9	Net Utility Plant	21,943,733	-	21,943,733	21,463,126	480,607
10						
11	Net Capital Lease Property	5,735		5,735	5,735	-
12	Net Nuclear Fuel Property	207,030		207,030	207,030	-
13						
14	Total Utility Property and Plant	22,156,498	-	22,156,498	21,675,891	480,607
15						
16	Less: Capital Lease Obligations	5,815		5,815	5,815	-
17						
18	Net Plant	22,150,683	-	22,150,683	21,670,076	480,607
19						
20	Allowance for Working Capital	1,364,943	-	1,364,943	1,364,943	-
21						
22						
23	Rate Base	\$ 23,515,626	\$ -	\$ 23,515,626	\$ 23,035,019	\$ 480,607

DTE Electric Company
Adjusted Net Operating Income
Projected 12 Month Period Ending December 31, 2026
(\$000)

MPSC Case No. U-21860
Exceptions to PFD
Attachment A
Page 3 of 4

Line No.	(a) Description	(b) Reply Brief Position	(c) Adjustments	(d) Exceptions to PFD Position	(e) ALJ Proposal for Decision	(f) Difference
1	<u>Operating Revenues</u>					
2	Sales Revenues	\$ 5,718,358	\$ -	\$ 5,718,358	\$ 5,722,151	\$ 3,793
3	Other Operating Revenue	-	-	-	-	-
4	Fuel and Purchased Power	1,353,470		1,353,470	1,353,470	-
5	Net Margin	4,364,888	-	4,364,888	4,368,681	3,793
6						
7	<u>Operating Expenses</u>					
8	Operations and Maintenance Expenses	1,382,150	-	1,382,150	1,241,909	(140,240)
9	Depreciation and Amortizations	1,358,612	-	1,358,612	1,325,819	(32,793)
10	Property Taxes	346,796	-	346,796	343,492	(3,304)
11	Other Taxes	52,064	-	52,064	52,064	-
12	Total Operating Expenses	3,139,622	-	3,139,622	2,963,285	(176,337)
13						
14	Operating Income	1,225,266	-	1,225,266	1,405,396	180,130
15						
16	<u>Other Operating Income Adjustments</u>					
17	Allow. For Funds Used During Constr	62,659		62,659	62,659	-
18	Amortization of Loss on Reacquired Debt	(2,435)		(2,435)	(2,435)	-
19	Other Income	6,425		6,425	6,425	-
20	Total Operating Income Adjustments	66,649	-	66,649	66,649	-
21						
22	PreTax Adjusted Net Operating Income	\$ 1,291,915	\$ -	\$ 1,291,915	\$ 1,472,045	\$ 180,130
23						
24	State Income Taxes	62,166	-	62,166	73,941	11,774
25	Federal Income Taxes	111,347	-	111,347	148,692	37,344
26						
27	Net Operating Income	\$ 1,118,401	\$ -	\$ 1,118,401	\$ 1,249,412	\$ 131,011

DTE Electric Company
Rate of Return Summary
Projected 12 Month Period Ending December 31, 2026
Based on Average Rate Base
(\$000)

MPSC Case No. U-21860
Exceptions to PFD
Attachment A
Page 4 of 4

Line No.	(a) Description	(b) Amounts (\$000)	Capital Structure		(e) Cost Rate %	Weighted Costs			(i) Pre-Tax Return
			(c) Percent Permanent Capital	(d) Percent of Total Capital		(f) Permanent Capital	(g) Total Cost %	(h) Conversion Factor	
Reply Brief Position (Test Period Average Basis)									
1	Long-Term Debt	\$ 9,076,192	49.25%	38.52%	4.29%	2.113%	1.65%	100.000%	1.653%
2	Preferred Stock	0		0.00%	0.00%	0.000%	0.00%	134.964%	0.000%
3	Common Shareholders' Equity	9,351,796	50.75%	39.69%	10.75%	5.456%	4.27%	134.964%	5.759%
4	Total	18,427,988	100.00%			7.568%			
5									
6	Short-Term Debt	562,850		2.39%	4.69%		0.11%	100.000%	0.112%
7									
8									
9									
10	Job Development - ITC - Debt	16,840		0.07%	4.29%		0.00%	100.000%	0.003%
11	Job Development - ITC Equity	17,353		0.07%	10.75%		0.01%	134.964%	0.011%
12	Total Job Development - ITC	34,192							
13									
14	Deferred Income Taxes (Net)	4,535,041		19.25%	0.00%		0.00%		0.000%
15									
16	Total	23,560,071		100.00%			6.04%		7.537%
Exceptions to PFD Position (Test Period Average Basis)									
17	Long-Term Debt	\$ 9,076,192	49.25%	38.52%	4.29%	2.113%	1.65%	100.000%	1.653%
18	Preferred Stock	0		0.00%	0.00%	0.000%	0.00%	134.964%	0.000%
19	Common Shareholders' Equity	9,351,796	50.75%	39.69%	10.75%	5.456%	4.27%	134.964%	5.759%
20	Total	18,427,988	100.00%			7.568%			
21									
22	Short-Term Debt	562,850		2.39%	4.69%		0.11%	100.000%	0.112%
23									
24									
25									
26	Job Development - ITC - Debt	16,840		0.07%	4.29%		0.00%	100.000%	0.003%
27	Job Development - ITC Equity	17,353		0.07%	10.75%		0.01%	134.964%	0.011%
28	Total Job Development - ITC	34,192							
29									
30	Deferred Income Taxes (Net)	4,535,041		19.25%	0.00%		0.00%		0.000%
31									
32	Total	23,560,071		100.00%			6.04%		7.537%

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

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on January 9, 2026, she served a copy of DTE Electric Company's Exceptions to the Proposal for Decision in the above captioned matter, via electronic mail upon the persons listed on the attached service list.

ESTELLA R. BRANSON

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MPSC Case No. U-21860

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MPSC Case No. U-21860

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