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October 27, 2023

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-21297

Dear Ms. Felice:

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

Very truly yours,

Andrea E. Hayden
Digitally signed by Andrea E. Hayden
Date: 2023.10.27 16:02:31 -04'00'

Andrea E. Hayden

AEH/cdm
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-21297

DTE ELECTRIC COMPANY'S EXCEPTIONS

TO THE PROPOSAL FOR DECISION

Dated: October 27, 2023

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I. INTRODUCTION

On October 5, 2022, the Administrative Law Judge (the ALJ) issued a Proposal for Decision (PFD). 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 DTE'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 believes that Michigan has great opportunities on the horizon. Strong energy policy coupled with a strong regulatory construct are the foundation necessary to provide Michiganders an affordable, reliable, resilient, and cleaner energy future, to attract business and provide economic growth to Michigan. DTE's customers, employees, communities, and investors expect implementation of the recently approved Integrated Resource Plan (IRP), electric distribution system upgrades, and reliable generation sources. The settlement of DTE's IRP was testament to Michigan's constructive regulatory environment.

By December 10, the Michigan Public Service Commission (MPSC) will determine DTE's ability to continue its journey to cleaner energy and build the grid of the future. Following years of historic grid and clean energy investments, and extraordinary inflation and rising interest rates without meaningful rate relief, the impact of this pending order will be significant for Michigan. The need for recovery cannot be overstated. A constructive outcome is possible here – one in which DTE customer bill increases remain lower than Midwest and national averages and in which DTE

receives the rate relief needed to continue critical investments in modernizing the grid and transitioning to a cleaner energy future.

No matter how modest a rate increase is, DTE recognizes the impact on vulnerable customers. Working closely with federal, state and agency partners to get aid to those in need is a top priority. In the 2021-2022 fiscal year, DTE connected customers to nearly $200 million in financial aid for their energy bills. Additionally, partnering with the Michigan Department of Health and Human Services, DTE directly applied aid to the accounts of many of its most vulnerable customers – work that was spotlighted by the White House. DTE continues to work with customers having difficulty paying their bills through several payment assistance programs and has expanded income-qualified Energy Efficiency (EEA) program to assist customers in making their homes more energy efficient and reducing their energy bills. The EEA program is delivered through over 30 nonprofit and community action agencies and has served over 50,000 customers with complete cost coverage since its inception. There is no scenario in which DTE's vulnerable customers will be left behind.

The Significance of This Rate Case

Unlike its Midwest and national peers, DTE has not had a meaningful base rate increase since May of 2020 due to two primary factors: 1) DTE opting against filing a rate case during the pandemic in 2020 and 2021; and 2) The Commission's low base rate order in 2022.

During the global pandemic, despite the need to recover a revenue deficiency at the time, DTE opted to stay out of rate cases to avoid placing additional burden on customers.[1] As the pandemic eased, DTE filed a $388 million rate case to implement new rates beginning in November

[1] To mitigate impact of rising rates, DTE accelerated accumulated deferred income tax (ADIT) amortization (Tax Cuts and Jobs Act of 2017). This temporary solution allowed DTE to cover its cost of service for that year only – like a band aid – and delay filing a rate case while the pandemic persisted, but the result was no increase in rates.

2022. The outcome was a Commission order of $30 million – about 8% of DTE's request, and far below even the Administrative Law Judge's (ALJ) recommendation of $145 million.[2]

The cumulative impacts of that 8% order, persistent inflation, the unrelenting impacts of climate change, and unfavorable weather now challenge DTE's ability to deliver safe, reliable, and affordable energy to its customers and communities. The MPSC will decide whether DTE will maintain the investments required to continue reducing carbon emissions and build the grid of the future – one that can both withstand the impacts of climate change and electrification transformation.

Elements of DTE's Rate Request

- **$102 million correction in sales forecast from the last electric rate case**
- **$278 million to support necessary investments**
- **$74 million of inflation and debt costs**
- $15 million in increased taxes
- $112 million of other increases

TOTAL = $580M

Approximately $454 million of this request is recovery for these three critical items alone:

1) Undisputed $102 million sales forecast correction from the last case;

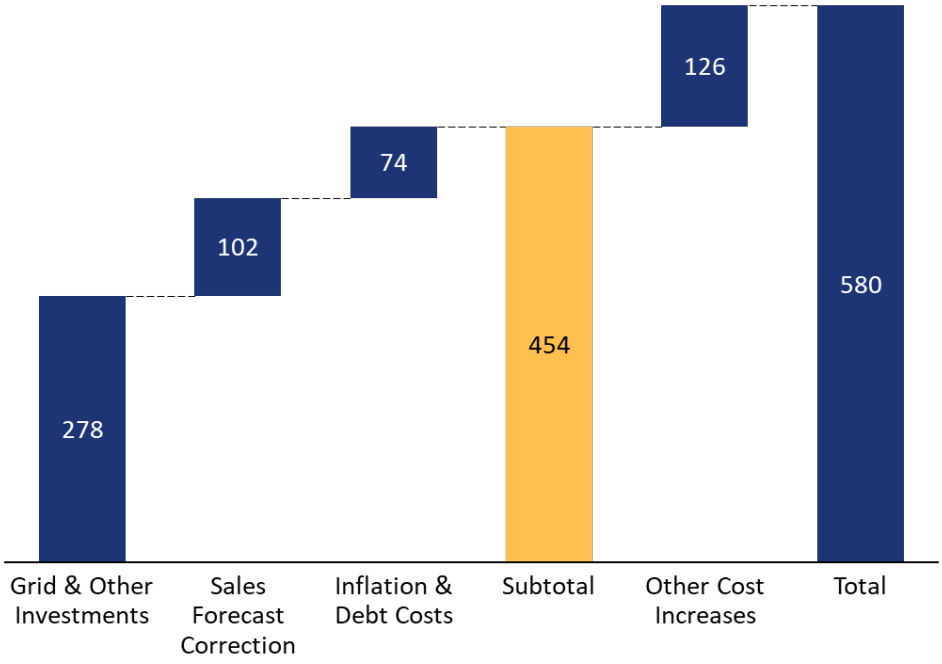
2) $278 million to recover customer-focused investments made in 2021-2023, and to be made in 2024; and

3) $74 million in inflation related expenses, including higher interest rates.

This level of rate relief amounts to an increase of 16 cents per day for the average residential customer. Absent the sales forecast correction from the prior case, the requested relief would have been much lower.

[2] The primary driver of the small order was the adoption of a never-before-used methodology on sales forecasting suggested by the Attorney General. In the present case, no parties have argued that the forecast was wrong by over $100 million to DTE's detriment.

Chart 1: Projected Revenue Deficiency by Cost Type ($ millions)



Current Case Status

As with every rate case, once DTE put forward its case, intervening parties advocated for disallowances. The MPSC Staff opined that DTE should recover $379 million in this case. The Attorney General, who has taken an especially critical position against rate increases in Michigan, determined that $326 million was appropriate. Despite these positions and the overwhelming evidence provided by DTE, the ALJ released a Proposal for Decision (PFD) on October 5th with a recommended revenue deficiency of $290 million.

Each of these recommended outcomes (MPSC Staff, the AG, and the PFD), if adopted by the Commission, will require sustained reductions in operating costs which will impact DTE's level of service to residential and business customers. Of greater concern, with no additional operating cost reduction levers remaining, DTE will need to pause or cancel critical investments.

Without Adequate Relief We Must Reduce Investments

Over the past year, DTE has implemented sweeping measures to mitigate the impacts of inflation alongside nearly flat base rates for the prior three years. These include reducing call center hours, reducing contractor staffing, suspending hiring, and delaying non-critical preventative maintenance on the grid and generation fleet. DTE implemented these measures without sacrificing safety or reliability – but these actions are not sustainable. Maintenance deferred on these assets will now become critical. With no remaining available operating cost reductions, a second consecutive order well below revenue needs will result in reductions to necessary investments in the grid and the clean energy transition. That means reduced investments in grid hardening and resiliency to combat climate change, automation to reduce the number of customers impacted by storms, and decommissioning of coal plants.

A Constructive Outcome is Possible

Residential Customer Impact

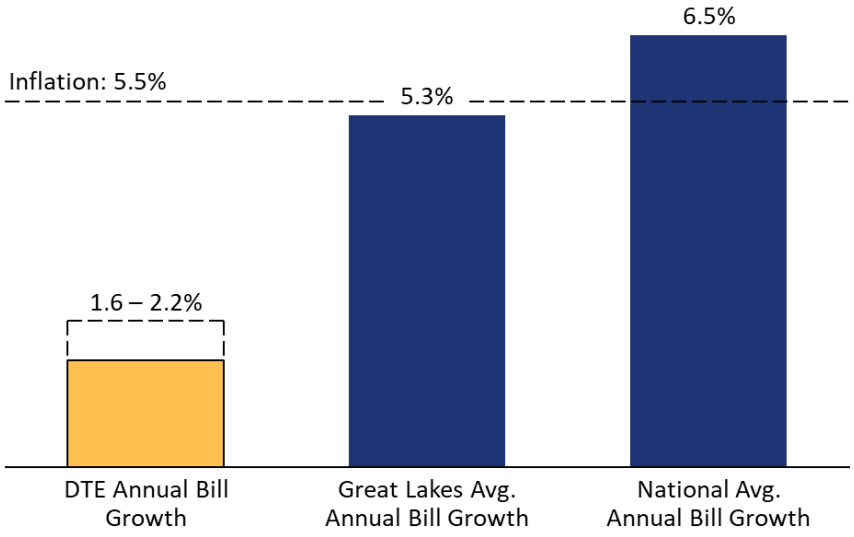
Nationwide, electric customers are experiencing rising rates as utilities grapple with the same challenges faced here in Michigan – increasingly volatile weather, elevated inflation, aging infrastructure, and the need to prepare for a future of increased electrification. Since DTE's last meaningful base rate increase in May 2020, Great Lakes[3] and national average residential bills have increased on average by 5.3% and 6.5% per year, respectively.[4] These increases are consistent with the level of inflation over that same period, with the average annual increase in the Consumer Price Index at 5.5%.

[3] Michigan, Indiana, Ohio, Illinois, and Wisconsin

[4] Based on most recent EIA data through July 2023

DTE's residential customers, on the other hand, have not experienced an increase in bills during the same period. In fact, even with a constructive outcome in this case, residential bill increases would remain well below both the rate of inflation and increases experienced by other utilities. For example, if the MPSC ordered full rate relief of $580 million, the average customer's bill would increase about 2.2% per year since May 2020.[5] Rate relief ordered at $454M would result in an average residential bill increase of 1.6% per year. The chart below illustrates these comparisons.

Chart 2: Comparison of annual residential bill growth (% increase per year)



[5] Through 2024

With full relief of $580 million, the average residential customer would pay 25 cents per day more in 2024 than what they pay today.[6] With rate relief of $454 million, the increase drops to 16 cents per day.

A constructive order in this case would lead to a reasonable increase in bills and would allow DTE to maintain its core operations, preserve cost-effective access to capital, and deploy necessary capital investments. These investments include, among other things, grid resiliency and expansion projects, a substantial improvement in reliability and in restoration performance in the aftermath of storms, decommissioning and dismantling of retired coal plants to the benefit of the communities in which they are located, building better digital channels for customers to connect with the Company, and ensuring that information technology systems are operated and maintained so as not to cause disruptions.

There are many disallowances recommended by the PFD, and they are discussed in detail within these exceptions. Of significant concern to DTE are some of the key disallowances that compromise the Company's ability to deliver the outcomes its customers deserve. These are summarized below.

III. OVERVIEW OF CRITICAL EXCEPTIONS

Despite the unprecedented depth of the record in this case, the PFD recommends unreasonable disallowances that will be detrimental to the Company's core functions, will reduce the Company's ability to accelerate grid reliability and safety improvements, and take important steps towards a future of cleaner generation. Additionally, the level of disallowances contemplated in the PFD if adopted could lead to a change in the perception of the regulatory construct in

[6] Inclusive of ordered rate relief and projected decrease in Power Supply Cost Recovery (PSCR) costs.

Michigan, a key risk factor utilized by rating agencies when developing a utility's credit rating. This increased perception of risk, along with the pressure on the company's credit metrics that would result from the disallowances, could increase the Company's borrowing costs which would be passed on to customers. The following are some of the most concerning recommendations included in the PFD:

- A $44 million disallowance for information technology (IT) operation and maintenance. This disallowance has significant consequences to the Company's IT operations. It slashes actual expenses for people and software that keep the Company's IT systems operational (for example, software licensing fees for the programs the Company's employees use every day, personnel for the Company's help desk, support for the telephone system). The PFD suggests a micro investigation into the necessary personnel and systems that the Company needs for its day-to-day operations, but this is well beyond the considerations required of the reasonable and prudent standard applicable in rate cases. A disallowance of costs that are based on actually incurred historical operating expenses in an important function such as the IT department sets a problematic precedent, as the Company will still need to fund the department to maintain operations and will need to rely on financial (cash) resources that would have otherwise been intended for investment in our grid and transition to cleaner sources of energy.
- Electric distribution infrastructure capital disallowances of $406 million, amounting to a $34 million revenue deficiency, which include disallowances for the replacement and hardening of aging infrastructure that is well beyond its useful life, as well as for the conversion of distribution systems built in the 1940's and 1950's to modern standards that will improve safety and reliability of the system. The majority of capital projects put forth

by DTE in electric distribution were supported by the MPSC Staff based on their deep understanding of the needs of the distribution grid, as amply documented in the instant case and in the Company's Distribution Grid Plans filed in 2018 and 2021. Yet the PFD recommended that virtually every proposed disallowance raised by other intervenors be accepted by the Commission. Should these recommendations be adopted, DTE's ability to improve reliability and meet the more stringent Service Quality and Reliability Standards that were approved this year will be significantly impeded. Importantly, even if some of the investments proposed for disallowance are ultimately included in rate base, disallowing other core operating costs, such as IT O&M as described above, will reduce the Company's ability to make such investments, as financial resources will need to be diverted from planned investments to supporting essential operations. In addition, the Commission has undertaken an effort that will consider the implementation of a system of incentives and penalties linked to improved reliability. Absent an ability to recover the costs of its investments, the Company will not be able to make progress towards the reliability improvements intended as part of this process. Regardless of when or whether such a system of incentives and penalties is implemented, the Company believes that substantial improvements in reliability are necessary and is fully committed to achieving the reliability its customers deserve.

- A $203 million disallowance for St. Clair, River Rouge, and Trenton Channel decommissioning costs, amounting to a $10 million revenue deficiency. The Company retired these plants with substantial stakeholder support. River Rouge has been closed since 2019 and both St. Clair and Trenton Channel retired last year – these decommissioning and dismantling projects are well underway. There should be no reasonable disagreement that

decommissioning the plants is a necessary next step and provides benefits to the communities in which the plants are located. Decommissioning is also needed and to make the sites ready for new investments, including the large-scale battery array that will be deployed at the Trenton Channel site included in the Company's recently approved Integrated Resource Plan.

- A $51.3 million disallowance amounting to a $11 million revenue deficiency impact for customer self-service IT investments. Not only do customers want to transact digitally, but the Company also put forth a compelling business case for these investments, one with positive financial value to customers – the clear benefit of making these investments led to both Staff and the AG supporting them. Improvements to our digital self-serve channels provide better service while also reducing live call center volumes and in turn decreasing operating costs. Through the implementation of self-service channels, customer call volumes were reduced by 1.87 million from 2013 through 2022. The ALJ has suggested that the Company must guarantee future savings for these projects, but again requiring this threshold of proof goes beyond the reasonable and prudent standard while ignoring the desires of our customers and the Company's historic success in reducing call volumes and their associated costs.
- Imputation of a $9.6 million tree trim surge savings. The PFD imputed additional cost savings suggested by the Attorney General beyond the $6.3 million identified by DTE for the tree trimming surge. The savings were correctly calculated by DTE Electric, and notably in the Company's last case the ALJ concluded that the Company's explanation and calculation are reasonable. Imputing an additional $9.6 million in savings double counts dollars that have already been reduced in the Company's annual tree trim budget. There is

no evidence in this case to suggest that any additional savings has been realized and finding otherwise incorrectly double counts savings already accounted for.

- A disallowance of $7.1 million related to inflation adjustments. The PFD recommends disallowance of $7.1 million in historical normalization adjustments to restoration O&M expense. The adjustments, foundational in accounting practice, are necessary to express past expenditures in a constant-dollar denomination (in this case, 2021 dollars) as the value of a dollar changes over time due to inflation. These recommendations not only arbitrarily reduce revenue requirement despite the Company's investments in prior years but are contrary to past rulings of the Commission which support the method of adjustment used by the Company in this case.
- A reduction in the Company's current return on equity (ROE) from 9.9% to 9.8%. This is a seemingly small downward adjustment with a very significant impact. In the current environment of rising interest rates and increased economic risk, more needs to be done to attract capital investment at reasonable rates, not less. A downward revision in ROE at a time of rising interest rates would be a signal of a deteriorating regulatory environment which could lead to higher borrowing costs from investors who could view Michigan as having become a riskier state offering lower returns on invested capital. While the Company believes that an increase in ROE is justified due to the current market conditions, at a minimum the current economic environment supports maintaining the status quo.

This is not a comprehensive list of the untenable disallowances proposed by the PFD, but it highlights crucial issues with the PFD's recommended $290 million revenue deficiency. Notably, the PFD also rejected the Company's proposed Infrastructure Recovery Mechanism (IRM), which was first advanced by the Commission as an option to be considered and further refined in the

instant rate case with input from Staff. An order in this case could be balanced to include customer protections related to DTE's execution on investments. The IRM was designed for this purpose and is intended to be a key enabler that will ensure that the appropriate investments in the grid are made by the Company, while also protecting customers from unwarranted rate increases should the Company be unable to execute all the investments contemplated in its request.

IV. LEGAL STANDARDS

The PFD presents a "Legal Standards" discussion (PFD, pp 29-30) 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 29) 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."[7]

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 to fair and just treatment in MPSC proceedings: "No person shall be compelled in any criminal case

[7] *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 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.[8] As a matter of fundamental ratemaking law, DTE Electric is entitled to a commensurate return of and on its investment in providing utility service.[9]

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." [10] Expert testimony is

[8] 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).

[9] 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).

[10] *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.[11]

When reviewing a PFD in response to exceptions filed by a party, the Michigan Administrative Procedures Act (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).

The PFD (at p 29) 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. [12] 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

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

[12] 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.[13] 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.[14] It is similarly well established that an agency decision may not be based on speculation.[15]

Logistically, DTE Electric has the initial burden to prove its case by a preponderance of the evidence.[16] 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

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

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

[15] *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).

[16] 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).

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 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 is unprecedented in length 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.[17] The Company further maintains that statutes must be applied as written,[18] and controlling precedent must be followed.[19]

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[17] 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."

[18] *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").

[19] See, for example, MCL 7.215(C)(2) and (J)(1).

Company witness Uzenski testified that generally, projects not in service in the projected test period have no net revenue requirement because of the Allowance for Funds Used During Construction (AFUDC) offset. AFUDC is applied to projects greater than $50,000 and lasting more than six months, with an exception for environmental and other specifically ordered projects. Disallowances of projects with an AFUDC offset have no impact to the amount of rate relief requested or approved. The correct result can be achieved by simply not reducing the Company's requested rate base and leaving the full AFUDC credit as filed in projected net income. (5T 1541, 5T 1573-1574).

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

V. DTE ELECTRIC HAS A $580 MILLION REVENUE DEFICIENCY

The Company revised its initial ($619 million) request to $583 million (See Initial Brief, Attachments A and B), and then made additional adjustments resulting in a revenue deficiency of approximately $580 million ($583 million without approval of the IRM) for the projected test year (See Reply Brief, Attachments A and B), which the Company continues to support.

The PFD recommended a $290.4 million revenue deficiency (PFD, pp 569, 858, Appendix A to PFD). The PFD's recommended revenue deficiency is insufficient and should be increased based on the controlling law outlined above, and the record evidence discussed below. Attachment A pages 1 through 4 to these Exceptions reflects the Company's position.

VI. DTE ELECTRIC'S RATE BASE IS $22.534 BILLION

DTE Electric's initially-filed rate base was $22.611 billion, which the Company adjusted to $22.344 billion (DTE Electric Initial Brief, pp 19-20) and adjusted further to $22.534 billion (DTE Electric Reply Brief pp 63) consisting of $21.283 billion of net plant balance and a $1.251 billion

working capital balance. Staff recommended a rate base of $22,452,387,000, consisting of $21,003,072,000 of Net Plant and $1,249,285,000 of Working Capital (Staff Initial Brief, pp 1, 4, 6; and Appendix B). The Attorney General suggested a $1,049.5 million reduction in rate base, based on various recommendations reflected on Exhibit AG-1.31 (AG Initial Brief, p 78).

The ALJ agreed with the Staff and AG on a number of issues and recommended a total rate base of $21.858 billion (PFD, p 413; Appendix B to PFD). DTE Electric takes exception and maintains that its Rate Base for the projected period ending November 30, 2024, is $22.534 billion.

A. Net Plant - Capital Expenditures

1. Energy Supply – Monroe.

Company witness Morren explained and supported total Energy Supply[20] capital expenditures of $524.6 million for 2021, $451.9 million for 2022, $958.6 million for the 23 months ending November 30, 2023, and $520.5 million for the projected test year (Exhibit A-12, Schedule B5.1, page 1, line 13, columns (b), (c), (e) and (f). See also generally DTE Electric's Initial Brief, pp 22-40). Energy Supply has a rigorous capital spending and approval process that is designed to identify the optimal allocation of capital resources to meet safety and environmental regulations, while maintaining overall reliability performance and reducing costs (Morren, 5T 2260, 2373).

Projected capital expenditures could be significantly reduced based on Monroe Units 3 and 4 retiring in 2028 as the Company proposed in its Integrated Resource Plan (IRP) and *voluntarily* addressed in this case.[21] This will allow several capital projects to be avoided or scaled back, lowering the required capital expenditures. The avoided or scaled back capital expenditures include

[20] In July 2021, the Company restructured some of its business units and combined Renewables Operations with the Fossil Generation business unit into a new integrated business unit called Energy Supply (Morren, 5T 2248).

[21] On July 26, 2023 Order, the Commission issued an Order Approving Settlement Agreement in Case No. U-21193.

over $42.2 million of routine capital expenditures (Morren, 5T 2341-48 and Exhibit MEC-13 page 5), $17.2 million[22] of non-routine capital expenditures related to the Monroe Bottom Ash Conversion (ELG) project (Exhibit MEC-13, page 1), and $21 million[23] of non-routine capital expenditures related to the Monroe Flue Gas Desulfurization (FGD) wastewater project.

Staff proposed a $39.9 million adjustment ($19,231,423 for the 11 months ending November 30, 2023; $20,628,303 for the projected test year) based on the assumptions that Monroe Units 3 and 4 are responsible for half of the common costs for the Monroe Bottom Ash (ELG) project and that 2023 costs can be avoided (Kindschy, 7T 4512). The PFD "concludes that Staff's recommended adjustment for this project should be adopted" (PFD, p 54).

The Company disagrees. Staff's assumptions are incorrect because common system costs (such as the common feed from the high-pressure general service water system and the sump system) will remain regardless of whether two units or four units are operational. Common costs also include engineering costs, which are not reduced by half if Monroe Units 3 and 4 retire in 2028. The Company identified $17.2 million of potential avoidable costs specific to Monroe Units 3 and 4 if the Company retires Units 3 and 4 in 2028 (Morren, 5T 2418-19; Exhibit A-35, Schedule Z13). Furthermore, Staff Exhibit S-21.1 confirms substantial ongoing (and unavoidable) construction expenditures throughout 2023 associated with Monroe Units 3 and 4 that could only reasonably be halted in August 2023 after the July 26, 2023 Order in Case No. U-21193 addressing the Company's Integrated Resource Plan. At most, inclusion of Monroe Unit 3 and 4 projected expenditures in Staff Exhibit S-21.1 for months remaining in 2023 following the Order in Case No. U-21193

[22] Exhibit MEC-13, page 1 includes the Company's discovery response MNSCDE-4.3cva that identifies $17.2 million of avoidable costs on the Monroe Bottom Ash (ELG) project. In direct testimony, MNSC Witness Comings refers to this exhibit, but appears to inadvertently identify the number as $17.4 million.

[23] The $21 million of non-routine capital expenditures related to the Monroe FGD wastewater project is projected beyond the timeframe of the instant case and is not included in the Company's request for rate recovery.

(August through December) totals $10.688 million, bringing the total potential avoidable costs to $27.9 million ($17.2 million for January through November 2024 expenditures + $10.7 million for August through December 2023 expenditures).

More specifically, The Company identified $6.5 million of avoidable costs for the Monroe Unit 3 Waterwall Tubes project (Morren, 5T 2343-44). Staff "agrees . . . and removes an additional $2,250,000 for this project that equates to half of the 2024 costs . . . ." (Kindschy, 7T 4514). The PFD "concludes that Staff's recommendation, supported by the testimony of Ms. Kindschy, is reasonable and should be adopted" (PFD, p 57).

The Company maintains that this additional amount is incorrect. It is based on an unfounded assumption that the cost of a waterwall replacement project is directly proportional to the square footage being replaced. There are many parts of a waterwall project that are not reduced by half simply because the square footage being replaced is reduced by half (e.g., erecting staging areas, installing temporary power and lights, and other examples listed in Mr. Morren's rebuttal testimony). These non-variable costs were considered by the Company in determining the $6.5 million of avoidable costs. This is the correct amount that should be used (Morren, 5T 2419).

In addition, the Monroe Unit 3 DCS & Control Room project replaces DCS hardware that was last replaced over a decade ago, and software that dates back to the 1980s and is no longer supported by the vendor. The Company identified $750,000 of avoidable costs (Morren, 5T 2343-44). Staff proposed a full disallowance ($1,176,000 for the 11 months ending November 30, 2023; $3,858,314 for the projected test year), reasoning that "Staff confirmed through discovery that all of the expenditures for this project in 2023 and 2024 are now avoidable with a 2028 retirement date for Monroe Units 3 and 4" (Kindschy, 7T 4513). AG witness Coppola also proposed a full ($3.823 million) project disallowance for 2024, using similar reasoning (6T 3713). The PFD states:

> This PFD finds that the DCS and control room costs should be excluded for the reasons explained by Staff and the Attorney General, and confirmed by DTE's discovery response at page 5 of schedule Z14, which indicates only that a portion of the project "may" be required. That DTE "may" spend some amount of money on this project is an inadequate justification for including it in projected rate base, and DTE's intransigence on this item calls into serious question its claim to use a "known and measurable" standard, or any appropriate standard, for its rate case projections. [PFD, p 60.]

The Company disagrees because, as indicated above, it proactively identified avoidable costs, as well as ongoing hardware and software issues. The PFD's characterization of the discovery response and further commentary are inaccurate and unjustified. The discovery response explains: "The current Monroe Unit 3 DCS could potentially operate through 2028. However, the DCS may require upgrades that the Company is reviewing. Additional analysis has to be performed before determining the extent of scope that could be avoidable" (Exhibit A-35, Schedule Z14). Therefore, portions of this project may still require completion in 2024, which can be reviewed in a future rate case (Morren, 5T 2419-20; Exhibit A-35, Schedule Z14 further reflecting how the Company has been keeping the equipment running to this point).

The Company also seeks to recover capital expenditures for installing backup power generators for the FGD equipment at Monroe (Morren, 5T 2323, 2325-27; Exhibit A-12, Schedule B5.1, page 6, lines 140, 149, 153, and 160). AG witness Coppola recommended $5,852,000 of reductions to the Company's Monroe 1-4 FGD Backup Generators project, incorrectly suggesting that the existing FGD system is flawed and that there is existing backup redundancy (6T 3709-10).

The PFD agreed with the AG, incorrectly concluding that "DTE was wholly nonresponsive to a legitimate [discovery] question" (PFD, p 65). To the contrary, the Company explained in the first sentence of the discovery response (included in Exhibit A-35, Schedule Z9, pages 1 through 4, and quoted at PFD, p 65) that the FGD systems were designed with back-up power to be provided by adjacent unit system service transformers in the event of a system service transformer or

auxiliary transformer failure. The Company also further explained that the existing design is sufficient if adjacent generation units are available, but in the event of a site blackout in which all generating assets are unavailable, that system would not allow for stabilization of critical FGD equipment, resulting in severe damage. This actually happened, requiring an extended outage to manually remove limestone slurry that had hardened (as discussed in Exhibit A-35, Schedule Z9).

The PFD further asserts that the Company's discovery "response raises more questions than it answers," including "a question of the reasonableness of the initial design and installation" (PFD, pp 65-66). Assuming for argument's sake that this speculation concerning a long ago decided engineering decision is even relevant, then the remedy would be follow-up discovery by the AG or cross examination of the Company's witness.[24] The ALJ's role was to weigh the parties' evidence and arguments. 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.[25]

The PFD also neglects that its suggestion that backup generation might have been provided earlier would have involved corresponding costs. The Company further notes that Mr. Coppola's suggestion that there could be less costly options "including temporarily obtaining power from the grid" (6T 3710) reflects a disregard of the Company's well-reasoned explanation over four (4)

[24] *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).

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

discovery questions and a lack of appreciation for the need to prevent system damage in the event of a site blackout, and that a site blackout might be part of a larger grid blackout (and the Commission is presumably well aware of the tightening of capacity resources).[26] Mr. Coppola also suggested that the project is wasteful due to the early retirement of Monroe units indicated in the Company's IRP (6T 3710). The Company disagrees because the backup generators will provide valuable protection from extensive FGD equipment damage (and therefore Monroe unit operability) through the remaining operational years. Therefore, the generators, which are already installed and expected to be operational by the end of this year, should be approved (Morren, 5T 2408-10).

After "find[ing] at this point the backup generator costs should not be included in projected rate base," the PFD further "recommends that the Commission allow DTE to present a report in its next rate case to establish that the additional costs it seeks to recover could not have been avoided or minimized with reasonable and prudent design and installation of the FGD system, and if additional costs are attributable to a design failure, to explain whether DTE has or had any recourse against the manufacturer or designer of that system" (PFD, p 66).

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[26] The Order in capacity demonstration Case Nos. U-21099 *et al*, discussed the Commission's concerns regarding the tightening of capacity resources, explaining in part:

> [The Staff report filed on March 25, 2022] also notes concerns regarding tightening capacity availability throughout the MISO zones and slimming margins for LRZ 7. *See*, Staff Report, pp. iii, 8, 17. The ***Commission shares these concerns regarding the tightening of capacity resources given the implications for resource adequacy and the economic and human impacts of capacity shortfalls. As described in last year's capacity demonstration docket,*** Case Nos. U-20866 *et al*., ***LRZ7 experienced a capacity shortfall that led to the PRA for that zone being set to CONE***. *Capacity Demonstration Results: Planning Year 2024/2025* in Case No. U-20886, filing #U-20886-0075, p. 4. While not included in this year's Staff report due to the MISO 2022/2023 PRA being conducted after the Staff Report was issued, the results were released on April 14, 2022. ***The MISO 2022/2023 PRA showed that all zones within the MISO footprint met their LCR, but LRZs 1-7 cleared at CONE, which for 2022/2023 is set at $236.66 per MW-day.*** [June 23, 2022 Order in Case Nos. U-21099 *et al*., pp 13-14; emphasis added.]

The Commission also recognized this concern in the July 2, 2021 Order in Case Nos. U-20886 and U-21099, p 10, which "emphasizes that the shortfall in LRZ 7 should serve as an important signal to Load Serving Entities (LSEs) of the severe economic consequences that could occur in the event of a loss of load event."

The Company maintains that the requested costs should be allowed as discussed above, so the PFD's recommendation regarding a report is moot. If the Commission orders any disallowance, however, then the Company agrees only that it should be able to further pursue cost recovery, and the Company reserves all rights to do so. The PFD's suggestion that the Company's options going forward should be limited to filing a report threatens an unlawful result.[27] Also, to the extent that the Company may file a report, the Company further objects to the PFD's characterizations as unfounded speculation suggesting that something is amiss and presuming a result.

The Monroe Wastewater Discharge System requires enhancements to process wastewater flows more efficiently, and sustain compliance with environmental permit requirements (Morren, 5T 2327; Exhibit A-12, Schedule B5.1, page 6, line 161). AG witness Mr. Coppola recommended disallowances totaling $7,007,000, suggesting that there is "uncertainty and conflicting information," because a discovery response "seems to refer to effectiveness and efficiencies and not to environmental risks" (6T 3711-12). The PFD states:

> This PFD finds Mr. Coppola's testimony persuasive that DTE's projected expenditures should not be adopted. The company can comply with its NPDES permit without this expenditure, and has not justified the costs relative to the alternatives to preventing coal pile runoff from contaminating the environment. [PFD, p 69.]

[27] For example, the First Amendment to the United States Constitution (which is applicable to the State of Michigan and its political subdivisions by operation of the Fourteenth Amendment) relevantly provides: "Congress shall make no law . . . abridging . . . the right of the people . . . to petition the Government for a redress of grievances." Michigan's Constitution similarly provides: "The people have the right peaceably to assemble, to consult for the common good, to instruct their representatives and to petition the government for redress of grievances." Const 1963, art 1, § 3.

The right to petition extends to all departments of government, including administrative agencies. *California Motor Transport Co v Trucking Unlimited*, 404 US 508, 510; 92 S Ct 609; 30 L Ed 2d 642 (1972). The Company's status as a privately-owned and government-regulated company does not preclude its assertion of First Amendment rights. *Consolidated Edison Co of New York v Public Service Comm of New York*, 447 US 530, 533-34; 100 S Ct 2326; 65 L Ed 2d 319 (1980) (holding that the New York Public Service Commission's suppression of bill inserts discussing public issues directly infringed the freedom of speech protected by the First and Fourteenth Amendments).

The Company disagrees. Mr. Coppola relied on a discovery response (included in Exhibit A-35, Schedule Z10) that makes no mention of any efficiency improvement. Mr. Coppola also suggested that it is uncertain whether the upgrade is necessary because the Company's IRP contemplates that Monroe Units 3 and 4 will retire in 2028 (6T 3712). The Company disagrees because Monroe Units 1 and 2 would continue to use this common coal pile runoff system into the 2030s. Therefore, the Company's requested recovery to process wastewater flows more effectively, and sustain compliance with environmental permit requirements should be approved (Morren, 5T 2410-11). The PFD's conclusion that "[t]he company can comply with its NPDES permit without this expenditure …" infers insight into the Monroe Wastewater Discharge System beyond information presented in the record and therefore lacks the evidentiary support required by law.[28] In sum, the Company properly explained and fully justified (*proactively* in direct testimony 5T 2259, 2341-2348) the potentially avoidable capital expenditures for Monroe Unit 3 and 4 associated with retiring those generation units in 2028 as the Company proposed in its Integrated Resource Plan.

2. Belle River Fuel Conversion.

The Belle River Fuel Conversion project is to convert Belle River's fuel source from coal to natural gas, consistent with the commitment to cease coal-fired operations,[29] and the Company's

[28] See MCL 24.285, which states in pertinent part: "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."

[29] DTE Electric's Initial Brief, pp 33-37, discussed ELGs (national wastewater discharge standards that are developed by the Environmental Protection Agency (EPA)), and the EPA's ELG Reconsideration Rule, which contains time-based options for complying with the updated rules for Bottom Ash Transport Water (BATW) and Flue Gas Desulfurization (FGD) wastewater. On October 13, 2021, DTE Electric submitted Notices of Planned Participation (NOPPs) to the Michigan Department of Environment, Great Lakes, and Energy (EGLE) for (1) cessation of coal burning at the Belle River Power Plant to achieve compliance with BATW discharge requirements, and (2) the Voluntary Incentive Program (VIP) at the Monroe Power Plant for FGD wastewater compliance (Lee, 5T 1255-57; Morren, 5T 2263). DTE Electric's NOPP for the Belle River Power Plant indicated a commitment to cease coal-fired

most recent IRP (Morren, 5T 2269-70; Exhibit A-12, Schedule B5.1, page 2, line 2). [30] ABATE witness York proposed a full ($38.763 million) disallowance. The ALJ acknowledged ABATE's support for the project, and the Company's testimony regarding completed engineering studies to confirm that the conversion is feasible, issuing an RFP to select an engineering, procurement, and construction (EPC) contractor, and that major design phases will be materially completed and long lead material will be procured in 2023; however, she asserted that "it is uncertain whether DTE will actually select an EPC in 2023, and whether the EPC will meet DTE's intended timelines" (York, 4T 1123). The PFD states:

> Based on the Commission's approval of the settlement agreement in Case No. U-21193, this PFD concludes that this project is reasonable. Nevertheless, recognizing that the costs DTE will incur through the test year are not known with certainty, and further recognizing that DTE is not seeking any rate relief in this case based on its planned expenditures for this project, because it proposes to include them in CWIP with an AFUDC offset, this PFD concludes that the projected costs should simply be excluded at this point. Generally speaking, it is this PFD's recommendation that DTE exclude from its rate case presentation, or separately present for informational purposes only, those projects that do not affect the company's revenue requirement in this case. By the time of DTE's next case, it should have signed contracts, and plans for the project to be in service during what will likely be a 2025 test year. [PFD, p 74.]

The Company agrees only with the conclusion that the project is reasonable. The PFD should have stopped there and recommended recovery. However, the PFD's suggestion that costs must be "known with certainty" is synonymous with the "beyond a reasonable doubt" evidentiary standard applicable only to criminal trials[31] and is contrary to the preponderance of evidence standard (which the PFD at p 29 correctly recognizes applies in this proceeding) and the use of a

operations by the end of 2028, with the option to evaluate a conversion to an alternative fuel source. This decision allows the Company to avoid installing $55 million of new ELG-compliant bottom ash technology by the end of 2025 (Morren, 5T 2263).

[30] On July 26, 2023, the Commission issued an Order Approving Settlement Agreement in Case No. U-21193.

[31] See Thangavelu v Dep't of Licensing & Regulation, 149 Mich App 546, 554-555; 386 NW2d 584 (1986); *Michigan State Employees Ass'n v Michigan Civil Serv Comm*, 126 Mich App 797, 802; 338 NW2d 220, 223 (1983).

projected test year (which the PFD agrees at p 36 is reasonable to use here). Furthermore, the future is inherently uncertain, so "certainty" cannot, applying reason, be the standard. The record further reflects that the indicated concern about the project moving forward is unwarranted because, for example, in April the Company responded in discovery that "EPC bids for the Belle River natural gas conversion project are due back to the Company in mid-May 2023". The Company did receive EPC bids in May. (Exhibit A-35, Schedule Z12; 5T 2414-16).

Witness York further suggested that recovery should be disallowed because the actual conversions will not occur until 2025 and 2026 (4T 1123). This PFD suggestion also neglects that expenditures in the bridge period and projected test year are for contracted work necessary to achieve successful and timely fuel conversion (Morren, 5T 2414). Anything other than full, timely rate recovery for reasonable and prudent projects with in-service dates outside the test year is also inconsistent with legal and regulatory practice. Project costs can be included in rate base if they are deemed reasonable and prudent regardless of whether they will be in service in the projected test year.[32] Under well-established accounting practice, and in compliance with the Commission's May 10, 1976 Order in Case No. U-4771, utilities may include construction work in progress (CWIP) in rate base because the revenue requirement is generally offset by an Allowance for Funds Used During Construction (AFUDC). AFUDC is applied to projects greater than $50,000 and lasting more than six months, with an exception for environmental and other specifically ordered projects. (Uzenski, 5T 1541, 1572-73).[33] There is no reasoned basis to account for the PFD's observations

[32] The Court of Appeals previously rejected the contention that the Commission has no authority to apply anything other than the "used and useful" test in setting rates. *ABATE v Public Service Comm*, 208 Mich App 248, 258-59; 527 NW2d 533 (1994). The Commission is not bound to apply any particular formula or use any specific method in setting rates. *Id*; *Detroit Edison Co v Public Service Comm*, 127 Mich App 499, 524; 342 NW2d 273 (1983); *Residential Ratepayer Consortium v Public Service Comm*, 239 Mich App 1, 6; 607 NW2d 391 (1999).

[33] If the Commission were to accept the PFD's proposition, then then the impact could be material, and the Commission should order a corresponding adjustment (reduction) in pre-tax AFUDC in projected net operating income to offset the removal of projects from approved rate base (Uzenski, 5T 1573).

or implement its recommended changes or limitations --- well-supported and fully examined reasonable and prudent projects like the Belle River fuel conversion should just be approved.

3. Coal Plant Decommissioning Costs.

AG witness Coppola and ABATE witness York proposed disallowances relating to the River Rouge, St. Clair, and Trenton Channel (frequently described as "Tier 2" plants) decommissioning projects (Exhibit A-12, Schedule B5.1, page 2, lines 32, 35, and 37). Regarding St. Clair, the PFD (at p 77) reflects that the Company and AG agreed about an adjustment due to the Company splitting the original project.[34] ABATE witness York proposed a full disallowance regarding St. Clair (originally $96.731 million) indicating various concerns, including that the Company had not received all necessary internal approvals (4T 1128). Witness York's proposed disallowance also included 2022 capital expenditures. The Company provided the actual amounts incurred in 2022 ($9.9 million) so there is no uncertainty about this cost (Exhibit A-35, Schedule Z5). The PFD correctly recognized that the $9.9 million should be recognized as removal costs in this case (PFD, p 81). The PFD otherwise agreed with ABATE, characterizing the Company's plans as uncertain (PFD, pp 79-81), and "conclude[ing] that the projected expenditures for the 11-month bridge period and projected test year are unsupported and should be excluded from the projected test year rate base" (PFD, p 82).

The Company disagrees with the PFD's reasoning and conclusion. It is true that the Company changed its plans after it filed this case, but it also reduced its recovery request. As

[34] AG witness Coppola proposed a $62.0 million reduction in the St. Clair decommissioning project, based on the Company deciding to split the project into two projects subsequent to filing this case, with the first project included in this proceeding, and the second project postponed for consideration in the next rate case (6T 3690-91). The Company generally agrees, but the correct calculation of the reduction should be $56.6 million (Morren, 5T 2402). "After review, the AG agrees with Mr. Morren's rebuttal correction" (AG Initial Brief, p 61). This changes the AG's initially-calculated revenue deficiency ($324 million) to $329.4 million (AG Initial Brief, p 61 n 176. See also pp 1, 4, 10).

indicated above, the Company split the project in two, and proactively and transparently explained that the Company only seeks recovery for the first project in the instant case. The first project has full internal approval, and the Company provided the related project approval forms in discovery and those approval forms were admitted as an exhibit (Exhibit A-35, Schedule Z7). Witness York also indicated a concern about contractual bids and vendor information concerning St. Clair, but this is irrelevant here because the selection of the demolition contractor will be part of the second project. Witness York also did not offer any specific criticism regarding reasonableness or prudence. Furthermore, there should be no reasonable disagreement that, having planned *for years* to retire Tier 2 coal plants, decommissioning these generation plants is the next necessary step. For all of these reasons, the PFD's proposed disallowance (to the extent that it exceeds $56.6 million as the correct reduction based on the project split as discussed above) should be rejected (Morren, 5T 2403-2404).

Regarding the River Rouge ($55.072 million) and Trenton Channel ($84.842 million) decommissioning projects, witness York indicated uncertainties including whether the Company received all necessary internal approvals (4T 11130-32). The Company disagreed, explaining that ABATE overlooked information. The Company provided the Capital Appropriation Request Forms (CARFs) that approved the complete River Rouge and Trenton Channel decommissioning projects in Mr. Morren's workpapers which were admitted as an exhibit (Exhibit A-35, Schedule Z8). Regarding witness York's indicated concern about RFP information, Mr. Morren's direct testimony indicated that the Company issued a demolition RFP, evaluated the bids, and selected a vendor in 2022 for the River Rouge project (5T 2283), and that the Company completed a demolition RFP and chose a vendor for the Trenton Channel project (5T 2286). Witness York's indicated concern that project costs are higher in this case than in Case No. U-20836 neglects that this case concerns

a different time period with projections beyond the prior case's timeframe. Witness York's proposed disallowances also improperly include 2022 capital expenditures. The Company provided the *actual* amounts incurred in 2022 ($13.0 million for River Rouge; $9.7 million for Trenton Channel) so there is no uncertainty regarding these expenditures (See Exhibit A-35, Schedule Z5). Witness York also did not offer any specific criticism regarding reasonableness or prudence. Therefore, the proposed disallowances should be rejected (Morren, 5T 2405-2407).

The PFD states:

> This PFD finds that DTE's projected 11-month bridge and test year costs for the demolition activities at the River Rouge plant have not been adequately supported and should not be included in rate base. As DTE's revision of its planned demolition plans for St. Claire [*sic*] show, in the absence of any particular reason to complete demolition activities, DTE is under no significant time constraints to do so. The project description on the CARF form on page 1 of Schedule Z8 of Exhibit A-35 contains essentially the same language as the CARF in Schedule Z7 that Mr. Morren relied on for the St. Claire [*sic*] demolition project. This document does not state the basis of cost estimates, and indeed indicates that the project will include "creating the bid documents used for both developers and demolition contractors," and thus cannot reflect the costs pursuant to an actual bid. While the CARF appears to have the required approvals, those do not commit DTE to conducting any particular demolition activities through the test year. [PFD, pp 84-85.]
>
> * * *
>
> This PFD finds that DTE has failed to support its projected 11-month bridge period and test year costs for [the Trenton Channel] project. While consistent with the discussion above, the company's actual 2021 and 2022 expenditures should be included in rate base as a reduction to the projected accumulated provision for depreciation, the projected costs should not be. The CARF forms that Mr. Morren relied on in Schedule Z8, pages 3 and 4, were signed days before DTE's application in this case, and contain the following description of work, with no additional basis provided for the cost estimates:
>
> > Initial appropriate request for decontamination, decommissioning and demolition of the Trenton Channel Power Plant. This includes the powerhouse, coal conveyance system, and all associated buildings (admin, clubhouse, etc.)

> Consistent with the discussion above, DTE has not shown any compelling timeframe for this work to be completed, and its decision regarding St. Clair work shows the malleable nature of its plans. [PFD, p 87. Footnote omitted.]

The Company agrees that 2021 and 2022 expenditures should be included in rate base, but otherwise disagrees. There should be no reasonable disagreement that, having planned *for years* to retire Tier 2 coal plants that include River Rouge, St. Clair, and Trenton Channel, decommissioning these generation plants is the necessary next step. Nevertheless, the PFD criticizes the Company's transparent (and near-term cost-saving) change of plans regarding St. Clair. This shows that the Company is requesting an appropriate amount, not that the amount should be reduced as the PFD suggests. The PFD's criticism of the CARF forms for not including additional or different information is misplaced because the forms reflect corporate approval to satisfy any reasonable concerns about projects having corporate approval. The CARF forms satisfy this purpose for an otherwise undeniable need as even the PFD acknowledges in the quote above. There has been virtual unanimity regarding the desirability of retiring the River Rouge, St. Clair, and Trenton Channel[35] power plants. The expenditures necessary to commence ultimate decommissioning of these generation plants must commence now and be recovered.

4. Blue Water Energy Center (BWEC).

Staff double-counted a Blue Water Energy Center (BWEC) contingency adjustment, with recommended disallowances of $8.1 million (DeCooman, 7T 4362) and $6.8 million (Rogers, 7T 4666), which combine to $14.9 million. The Company explained that Staff's proposed disallowances are related to the same thing, and should not exceed the $8.1 million of contingency

[35] See also Exhibit AG-1.91 explaining plans (approved in Case No. U-21193) for the Trenton Channel BESS project to be constructed on this same site.

that the Commission did not include for recovery in Case No. U-20836 (Morren, 5T 2423-24). The PFD states:

> This PFD finds that Staff's analysis of the contingency in the company's expenditures is credible and should be adopted. DTE should not be including any contingency in its projections, and should not be requiring Staff to tease out contingency from its expenses. DTE needs more than a claim that Staff is confused or double-counting, when DTE should have adequate information at its disposal to establish its actual expenditures. [PFD, p 91.]

The Company disagrees because the $6.8 million was the portion of the $8.1 million that was included in 2023 capital.[36] The remaining $1.3 million was in 2022. There is nothing to "tease out," and the PFD's unnecessary commentary does not add further clarity.

There is only $8.1 million of contingency which was removed by the Company in its Reply Brief while reserving its right to seek future recovery.

The BWEC Conference Room Building project involves $5 million to construct a new building at the BWEC site to provide a safe location away from plant operations to accommodate large work crews for outages, site-wide meetings, and visitors (Morren, 5T 2359-60; Exhibit A-12, Schedule B5.1, page 7, line 234). AG witness Coppola proposed a full disallowance, reasoning that "the Company provided only minimal information that makes it impossible to assess the need for the new building" (6T 3717). The Company disagrees and the record refutes the assertion because it provided discovery responses (included in Exhibit A-35, Schedule Z11 pages 1-8) that show a good faith effort to provide as much detail as possible through responses to eight discovery requests, and Mr. Coppola did not indicate how additional (often security sensitive) information would be relevant to determine whether the project is justified (Morren, 5T 2412-13).

[36] Exhibit S-12.2, page 3

ABATE witness York similarly proposed a $5 million disallowance, reasoning that project timing is unclear (4T 1134). The Company disagrees because the project has already commenced and is expected to be completed in September 2024. Therefore, the Company's requested recovery should be approved (Morren, 5T 2413; Exhibit A-35, Schedule Z3 Revised).

The "… PFD finds Mr. Coppola's and Ms. York's testimony persuasive that DTE's plans for this project are insufficiently definite to warrant funding at this stage" (PFD, p 96). The Company disagrees based on the record demonstrating, inter alia, that *"[t]he Company has facilities at each power plant that have been used regularly for decades for similar purposes that the new BWEC building will serve"* and it was the AG and ABATE who failed to provide anything more persuasive than the mere allegation that the Company's evidence is "minimal" or not enough. (Exhibit A-35, Schedule Z3, p. 8) Unsupported conclusory assertions cannot stand in place of the Company's actual evidence, are unpersuasive in the face of the Company's actual evidence, and cannot support a lawful Commission decision on the matter.[37] The BWEC Conference Room Building project has commenced and warrants funding as discussed above.

5. Site Security/NERC.

ABATE witness York proposed disallowances of $8.8 million for site security projects, and $1.7 million for North American Reliability Corporation (NERC) compliance projects (reflected at Exhibit A-12, Schedule B5.1, page 2, lines 8-18), acknowledging that the Company supported its requests with testimony and PMP forms provided in workpapers, and offering no reason for any

[37] *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).

disallowance other than a reference (without discussion or analysis) to the Commission disallowing costs in Case No. U-20836 (4T 1126-27). The Company explained that witness York's proposal should be rejected because the Company supported its requests here with testimony and PMP forms provided in workpapers. The record adequately supports the projects and reflects that they have Company approvals (Morren, 5T 2275-77, 2391). It should also be noted that Staff and AG made no recommendations nor express any concerns related to the Company's Site Security or NERC compliance projects (Morren 5T 2390).

The PFD proposed disallowing recovery because "… for those site security and NERC projects with costs projected for the 11-month bridge period or future test year, the capital costs should be excluded from rate base because the parties were not able to evaluate the reasonableness and prudence of the projects, the basis for the project cost estimates, or the likelihood that DTE will spend the money as projected in schedule B5.1. (PFD, p 98). As part of the ALJ's assessment, faulty comparisons are made at page 100 of the PFD between the Company's Schedule B5.1 and project documents included in Exhibit AB-7. The ALJ compares the annual expenditures included in the Company's Schedule B5.1 which exclude calculated risk (aka contingency)—apples—to annual expenditures in project documents that include calculated risk (aka contingency)—oranges. Based on a sizable difference between these two sets of numbers, the ALJ concludes the forms do not support the Company's cost projections. To the contrary, when these projects are compared on the same basis (i.e. without contingency), the Company's project documents fully support the Company's requested expenditures. The Company maintains that it adequately supported its projects by providing disclosable project scope and schedule details in direct testimony (5T 2275-2277) and internal project approval documents in workpapers, and full cost recovery should be

approved. The *sua sponte* misinterpretation of discovery responses in the PFD cannot form the basis for a lawful Commission Order on the matter.

6. Black Start.

ABATE witness York proposed a complete ($46 million) disallowance for three black start projects (4T 1127). The proposal concerns 2024, as well as work completed in 2022 and year-to-date in 2023 totaling over $23.6 million (Exhibit A-35, Schedule Z5). Witness York vaguely suggested that nothing has changed since Case No. U-20836, but the record reflects that conditions are materially different. The projects have full management approval (reflected in witness York's own Exhibit AB-7), and substantial work totaling over $23.6 million has been completed. Therefore, ABATE's rationale has been persuasively refuted and the proposed disallowance should be rejected (Morren, 5T 2393).

The same response largely applies to AG witness Coppola's proposed total ($46,320,000) disallowance for three black start projects (6T 3699-3700). In response to his further suggestion that the Company did not answer discovery (6T 3700), Mr. Morren explained that the Company answered the discovery questions consistent with the security sensitivities involved. Mr. Morren also summarized and amplified the previously provided discovery answers to assist in better understanding what black start means, and how a generation asset can function as a black start resource. Therefore, the AG's insubstantial concerns and proposed disallowance should be rejected (5T 2394-96).

Notwithstanding, the PFD instead "finds Mr. Coppola's and Ms. York's testimony persuasive that they were unable to adequately review or evaluate the projects at issue to evaluate the projects, the reasonableness of the projected costs, or the reliability of the projected timing of the expenditures" (PFD, p 105). The Company disagrees, incorporating the discussion above, and

further emphasizing the impropriety of the PFD's proposed full disallowance.[38] Black start project funding relates to compliance with North American Reliability Corporation (NERC) reliability standards. The Company cannot disclose specific locations and specific work efforts associated with black start facilities because they are considered critical infrastructure systems by MISO. Also, as reflected in response to discovery, the Company does not decide the extent of resources needed for black start. Instead, the relevant analysis and decisions rest with ITC and MISO (Morren, 5T 2394).

The PFD also states, "to the extent that it is possible to match the project documents in Exhibit AB-7 to the line items in Schedule B5.1, page 2, it appears that the projected expenditures on those documents do not match the projections in lines 47-49" (PFD, p 106). Similar to the PFD's inapt assessment of Site Security/NERC projects above, the PFD engages in further faulty comparisons at pages 106-107 of the PFD between the Company's Schedule B5.1 and project documents included in Exhibit AB-7. The PFD again incorrectly compares annual expenditures included in the Company's Schedule B5.1 which exclude calculated risk (aka contingency)—apples—to annual expenditures in project documents that include calculated risk (aka contingency)—oranges. Based on a sizable difference between these two sets of numbers, the ALJ incorrectly concludes that the forms do not support the Company's cost projections. When these projects are compared on the same basis (i.e. without contingency), the Company's project documents fully support the Company's requested expenditures. The Company maintains that it adequately supported its projects by providing disclosable project scope and schedule details in direct testimony and internal project approval documents in workpapers, and full cost recovery

[38] Staff's Initial Brief, pp 19-21, proposed a combined $6.5 million reduction in the Company's requested funding for three black start projects.

should be approved. The *sua sponte* misinterpretation of discovery responses in the PFD cannot form the basis for a lawful Commission Order on the matter.

7. Batteries – Trenton Channel BESS Project.

This request (2025/2026 Battery, at Exhibit A-12, Schedule B5.1, page 2, line 52) reflects expenditures needed for engineering and long lead material procurement to support 46 MW of build in 2025, and 60 MW of build in 2026, at the recently-retired Tier 2 Trenton Channel Power Plant, consistent with the Company's proposed course of action (PCA) in its most recent IRP, Case No. U-21193 (Morren, 5T 2295). The project was later expanded and accelerated to be a 220 MW lithium-ion BESS with a target COD in 2025, as reflected in Case No. U-21193.

The AG recommended full ($81.2 million) disallowance, largely because the Commission had not yet rendered a decision in Case No. U-21193. The Company disagrees because the project is consistent with the Company's IRP (Morren, 5T 2400). [39] ABATE witness York similarly proposed a full disallowance, essentially reasoning that the Company did not support its request with enough detail (4T 1132). In addition to the discussion above, the Company disagrees because it supported the project, and it had sufficient project and timeline detail to bid the project earlier this year (as reflected in discovery responses, which are consolidated as Exhibit A-35, Schedule Z6). The Company further notes that the project will allow the Company to take advantage of economies of scale during material procurement and site construction. This is the preferred location for the near-term battery deployment due to the large amount of land available, and the ability to repurpose the Trenton Channel Unit 9's transmission interconnection rights using MISO's generating facility replacement process. The Company has three years from the time Trenton Channel Unit 9 retired in 2022 to re-use interconnection rights. The ability to reuse an existing

[39] On July 26, 2023, the Commission issued an Order Approving Settlement Agreement in Case No. U-21193.

generator interconnection has several benefits including a significant time reduction as compared to a new generator interconnection, and avoiding the need to pay for land acquisition, engineering study costs, electrical tie-in infrastructure, and network upgrades (transmission projects).[40] Therefore, full cost recovery is fully justified and should be approved (Morren, 5T 2295-97, 2400-2401).

Staff proposed a partial disallowance of $72,227,000, indicating Staff's belief that this would be appropriate although "Staff understands the Company's desire to execute this project in a timely manner that allows for the capture of all the benefits identified" (Staff's Initial Brief, p 26). The Company appreciates Staff's partial support and indicated recognition of the need to move forward expeditiously, and maintains that full cost recovery should be approved as indicated above.

The PFD states:

> Notwithstanding the importance of this project to the IRP that the Commission approved in Case No. U-21193, this PFD concludes that it is premature to include the projected costs in rate base. While Staff's proposal to include $9 million in engineering costs is not unreasonable, it appears to be based on a desire to have ratepayers fund the beginning of this project, but in theory, as Ms. Uzenski explained it, the costs at this premature stage should be in CWIP with an AFUDC offset, since the project is clearly going to cost more than $50,000 and take more than six months. This ratemaking treatment would not actually provide DTE with funding, and ignores that DTE has a generous working capital allowance and line of credit for activities of this nature. Notwithstanding the Attorney General's current opposition, there is no dispute that this project is consistent with DTE's approved IRP, but that does not require including preliminary stage expenditures for this project in rate base, which no party disputes will not be in service until at least 2025. [PFD, pp 112-13.]

[40] Mr. Morren further explained in a discovery response (Exhibit AG-1.91) that:

> The project should be approved because it supports the broader transition of our fleet as further defined and justified by analysis in the Company's 2022 IRP case No. U-21193. As stated in my revised rebuttal testimony, page 26, lines 8-10, "…the Company's 2022 IRP was a comprehensive analysis that supported the build-out of grid-scale batteries. The 2025/2026 battery in the instant case is consistent with the build plan included in the Company's 2022 proposed IRP PCA." However, the time-limited interconnection window presents an additional justification and benefit that would otherwise be lost if the Trenton Channel BESS projects are not approved.

The Company disagrees. In addition to the discussion above, the PFD's reasoning that the expenditures "should be in CWIP" and "not . . . in rate base" neglects that CWIP *is* in rate base, as reflected for example by Appendix B to the PFD. As previously stated, Company witness Uzenski explained that projects not in service in the projected test period have no net revenue requirement because of the AFUDC offset (5 T 1541, 5 T 1573-1574).

8. Fuel Supply and Midwest Energy Resources Company.

Mr. Milo supported DTE Electric's Fuel Supply and Midwest Energy Resources Company (MERC) capital expenditures for 2021 through the projected period ending November 30, 2024. The capital expenditures of $2.7 million for 2021, $4.6 million for January 2022 through November 2023, and $2.5 million for the projected test year (as shown on Exhibit A-12, Schedule B5.2), relate to improving safety, meeting environmental requirements, reliable operations, and/or replacement of end-of-life equipment. Mr. Milo confirmed "[t]here are no plans to spend capital on items that are not critical to continued safe operations" (5T 2547). The capital expenditures are reasonable and prudent, and necessary to extend and/or improve Fuel Supply operations and MERC's coal transshipment capabilities (Milo, 5T 2544, 2546-49; Exhibit A-12, Schedule B5.2, columns (b), (e) and (f)). Therefore, the expenditures should be approved.

MNSC witness Jester indicated that he would expect DTE Electric to use a declining volume of coal in future years based on the conversion of Belle River to natural gas and the retirement schedule for Monroe indicated in Case No. U-21193 (6T 3461), and suggested that "the Commission disallow the proposed capital expenditures at MERC pending a determination of its retirement date and disallow proposed capital expenditures on coal transportation equipment pending a determination of the appropriate retirement schedule for that equipment." (6T 3462).

The Company explained that MNSC's proposal to disallow MERC capital expenditures ($1.5 million in the projected test year) should be rejected because MERC is a critical transshipment source of coal for Belle River, which is designed to primarily receive coal deliveries by vessel. MERC is also crucial in supplying a significant portion of the western coal used at Monroe, so MERC's continued safe operation is indispensable in providing reliable electricity to customers through the projected test year and beyond. In addition to Mr. Jester failing to suggest any alternative, Mr. Milo explained that no other transshipment facilities could perform the required services at the cost MERC provides, and providing for deliveries by rail to Belle River would require significant and costly modifications to the coal unloading system, which would be operational for only a short period of time until the conversion.[41] Moreover, MERC continues to provide a reduction in DTE Electric's (and its customers') PSCR expense through third-party revenues (Milo, 5T 2553-54, 2556-57).

The Company further explained that MNSC's proposal to disallow capital expenditures on railcars ($1.0 million in the projected test year) should similarly be rejected because DTE Electric maintains the railcar fleet not only to control coal deliveries to its power plants, but also to optimize the cost savings associated with rail transportation by using private equipment. It is critical to rebuild railcar trucks on the 1997-1999 vintage cars to extend the truck's useful life and operability consistent with expected operations, so that these railcars remain in safe and reliable operating

[41] Mr. Jester also inaccurately asserted that MERC's "[c]apital expenditures per ton are increasing from $0.18 in 2022 to $0.49 in 2024" (6T 3461). He incorrectly computed 2024 capital costs as $2,643,000 based on the 23-month bridge period. Using $1.5 million from the projected test year would result in $0.28 per ton. However, the whole exercise of calculating cost per ton is also unsound because capital expenditures for replacing end-of-life equipment, operating the facility in a safe and reliable manner, and maintaining environmental compliance do not change based on the volume of coal transshipped. Moreover, Mr. Jester's own Exhibit MEC-6 also reflects that MERC's annual capital expenditures have decreased since 2013, demonstrating that MERC has taken prudent steps to reduce its capital costs (Milo, 5T 2555-56).

condition to support DTE Electric's coal transportation needs through the projected test year and beyond (Milo, 5T 2548-49, 2554-57).

Mr. Jester further recommended that the Commission "require DTE Electric to propose in its next depreciation case that MERC, including any future capital expenditures, be fully depreciated by its planned retirement date and that any coal transportation assets held by DTE Electric also be fully depreciated by their expected retirement dates" (6T 3462). The Company agrees to update MERC depreciation rates based on its best estimate of a retirement date in its next depreciation case, but does not agree to Mr. Jester's broader proposal to include coal transportation assets in that proposal, incorporating the discussion above (Uzenski, 5T 1565, 1578).

The PFD states:

> This PFD finds that DTE has not adequately evaluated the operation of MERC and its fuel supply infrastructure in planning the projected investments, including an evaluation of the necessity of the investments and their value to ratepayers in light of the significantly diminished transportation volumes. This PFD finds that it is reasonable for DTE to reevaluate these investments, and that the alternative suggested by MNSC to allow DTE to defer recognition of additional costs following such a reevaluation would be appropriate. For example, regarding DTE's proposed refurbishment of the railcars, it possible that the investment will substantially increase the salvage value of the railcars, but no such consideration appears to have been undertaken by the company. Further supporting this deferral, since DTE has not evaluated a retirement date for MERC or for related fuel supply assets, it is possible that it will identify alternatives to these investments that allow the company to meet its needs and commitments over a shorter term at lesser cost. [PFD, pp 120-21.]

The Company disagrees with the PFD's unsupported speculation because the record fully supports its requested cost recovery in this case, as outlined above. In sum, despite the undisputed continuing need for reliable coal transportation for the foreseeable future, MNSC unreasonably and imprudently suggested, and the PFD agreed, that the Commission disallow the recovery of relatively modest costs that are necessary to maintain safe and reliable operations (Milo, 5T 2548-

59, 2554-57). The PFD's further speculation that it is "possible that the investment will substantially increase the salvage value of the railcars" cannot lawfully support a Commission decision [42].

The PFD also essentially faults the Company for not providing additional evidence, neglecting that MNSC raised the issue, so they have the burden of proof.[43] In addition to the Company supporting its expenditures as discussed above, MERC is a well-established component of the Company's generation infrastructure, and there is no requirement for the Company to re-prove MERC's fundamental nature in successive cases (as reflected, for example, by PFD, p 114, referencing Case No. U-5108). Mr. Jester's own Exhibit MEC-6 also reflects that MERC's annual capital expenditures have *decreased* since 2013, demonstrating that MERC has taken prudent steps to reduce its capital costs (Milo, 5T 2555-56). The PFD suggests that the Company's position on Exhibit MEC-6 is "unsupported by the record" (PFD, p 121). To the contrary, that exhibit shows MERC's significantly *decreasing capital costs* in the last ten years ($3.0 million to $4.4 million from 2013-2018; $0.9 million to $1.7 million from 2020-2023; $1.5 million projected for 2024), and Mr. Milo's testimony about the decreasing costs reflecting prudent steps to reduce capital costs is substantial evidence sufficient to properly support a decision. [44] And most critically, DTE Electric has continuing fuel transportation needs in order to properly serve customers and the capital expenditures shown on the Company's Exhibit A-12, Schedule B5.2 relate to improving safety,

[42] *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).

[43] *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), ("The party alleging a fact to be true should suffer the consequences of a failure to prove the truth of that allegation").

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

meeting environmental requirements, reliable operations, and/or replacement of end-of-life equipment. Mr. Milo confirmed "there are no plans to spend capital on items that are not critical to continued safe operations" (5T 2547). Those expenditures are reasonable, prudent, and necessary to extend and/or improve Fuel Supply operations and MERC's coal transshipment capabilities (Milo, 5T 2544, 2546-49; Exhibit A-12, Schedule B5.2, columns (b), (e) and (f)).

For all of these reasons, the Company's requested cost recovery should be approved.

9. Nuclear - Fermi 2.

DTE Electric's Initial Brief, pp 43-44, explained and supported the capital expenditures for the Fermi 2 Nuclear Power Plant (Fermi 2), noting that the Company reduced its projected revenue deficiency because it changed the projected installation date of the Main Unit Generator project (depicted on page 4, line 2 of Exhibit A-12, Schedule B5.3) to the next refueling outage (RF23) (Exhibit S-25). Staff's Initial Brief, p 27, similarly noted adjustments due to the timing of the Fermi Generator Project. Despite the absence of any disagreement and the PFD acknowledging that "DTE imitated Staff's treatment, including the projected expenditures in CWIP as shown in Attachment A to its reply brief, page 3," the PFD suggests that there "seems to be some confusion between DTE and Staff as to how the change in plans should be reflected in rates" (PFD, p 123). The PFD then further asserts:

> This PFD finds that with the change in DTE's plans, there is no reason to assume that it will in fact spend the projected amounts reflected in its exhibits, and thus no reason to include such amounts in projected CWIP, whether or not it has any impact on the revenue requirement to do so. [PFD, p 124.]

The Company disagrees because, as indicated above, there is no disagreement or confusion, so the PFD's assertion is unfounded. Under well-established accounting practice, and in compliance with the Commission's May 10, 1976 Order in Case No. U-4771, utilities may include construction

work in progress (CWIP) in rate base because the revenue requirement is generally offset by an Allowance for Funds Used During Construction (AFUDC). AFUDC is applied to projects greater than $50,000 and lasting more than six months, with an exception for environmental and other specifically ordered projects. (Uzenski, 5T 1541, 1572-73).[45] As the PFD acknowledges, the Company's (and Staff's) presentation results in there being no current revenue requirement for this project.

10. Distribution Operations (DO).

i. Overview and Response to the PFD's General Concerns and Recommendations

DTE Electric's Distribution Operations (DO) organization focuses on the safe and reliable design, construction, maintenance and operation of the Company's electrical distribution system and subtransmission system, which are often referenced collectively as "the distribution system" (Robinson, 5T 2679).[46] DTE Electric's distribution system is aging, and, in many cases, equipment is operating near or beyond typical design life (Robinson, 5T 2686-87). Aging infrastructure combined with more frequent and intense weather require grid upgrades and modernization changes. These changes are necessary and foundational to support growth in distributed energy resources (DER) and load growth associated with electric vehicle (EV) penetration, and expanding regional economic activity requires a more robust, resilient, and modern grid infrastructure. The capital investments (discussed here) and O&M expenses (discussed in section VI. B. 3) are

[45] If the Commission were to accept the PFD's proposition, then the impact could be material, and the Commission should order a corresponding adjustment (reduction) in pre-tax AFUDC in projected net operating income to offset the removal of projects from approved rate base (Uzenski, 5T 1573).

[46] DO consists of eleven suborganizations: (1) Central Engineering; (2) Regulatory Strategy and Grid Modernization; (3) Scheduling & Construction; (4) Project Management Office; (5) Operational technology; (6) Advanced Distribution Management System (ADMS) project team; (7) Regional Customer Operations; (8) System Operation; (9) Emergency Preparedness & Response; (10) Tree Trimming; and (11) Substation Operations (Robinson, 5T 2679-82).

necessary to achieve the Company's goals of providing safe and reliable electricity to customers at reasonable rates. These investments also lay the foundation for grid modernization, which customers require to support their evolving needs for greater resiliency in the face of increasingly frequent and intense storms, electrification including EVs, and integration of DER (Miller, 5T 2840).

DO capital expenditures totaled $1.27 billion in 2021 and are projected to be $2.82 billion for the 23-month bridge period ending November 30, 2023, and $1.56 billion for the projected test year (Miller, 5T 2839; Exhibit A-12, Schedule B5.4, page 1, line 23, columns (b), (e), and (f)).

The Company's projected DO capital expenditures in Case Nos. U-20162 and U-20561 were based on an evolution of the Five-Year Plan that was submitted in Case No. U-20147. The August 20, 2020 Order in Case No. U-20147 re-affirmed the Commission's over-arching objectives (safety, reliability and resiliency, cost effectiveness and affordability, and accessibility) and issued updated distribution plan requirements and guidance. Accordingly, on September 30, 2021, DTE Electric filed a final 2021 Distribution Grid Plan (DGP; Exhibit A-23, Schedule M7) that provides both a detailed five-year investment plan, and a longer-term 10- to 15-year vision for the grid (Robinson, 5T 2692-93). This DGP provided a foundation for the DO capital expenditures in Case No. U-20836.

To support the need for and prioritization of grid investments, Mr. Kryscynski explained that strategic investment programs are evaluated against seven impact dimensions in the Company's Global Prioritization Model (GPM), which is a "best fit, most-reasonable cost" framework that the Company developed to assess the impact that strategic investment programs and projects are

expected to have on the grid in order to meet customer needs (Kryscynski, 3T 385-90). Table 4 at Kryscynski, 3T 392, shows the top 50 Strategic Capital investments (Kryscynski, 3T 390-92).[47]

The PFD presented a number of conclusions regarding the GPM utilized by the Company for prioritization projects presented in this case (PFD, pp 187-191) with which the Company disagrees.

The Company disagrees to the extent that the PFD seems to suggest a stand-alone DGP case, noting that the suggestion vaguely reflects AG/MNSC witness Alvarez's assertion that "distribution investment plans should be presented and evaluated in litigated proceedings" (6T 3345). The DGP has already been considered in Case No. U-20147 in which it was open for comment and evaluation. The Company also disagrees because the DGP outlines the Company's goals for safety and reliability in the longer term, and the investments that are planned in the shorter (5 year) term to achieve its goals. There is no need for this type of planning to be subject to a litigated case. Moreover, a non-litigated plan is what the Commission envisioned (January 31, 2017, Order in Case No. U-18014, pp 40-41), and there is no evidence that the DGP process has limited the Commission's ability to review proposed investments for reasonableness and prudence in rate cases. The current DGP process also provides for stakeholder feedback, and the Company incorporated feedback as appropriate. There is similarly no sound basis for witness Alvarez's proposal to establish a series of workgroups to develop distribution plan requirements (6T 3343) because that has already happened. The current distribution plan requirements, which the 2021 DGP met, were developed through a series of workgroups led by Staff and included participation by the

[47] Tree trimming is a high-priority strategic program, but it is not in the table because the costs are O&M, and not capital (Kryscynski, 3T 390). See section VI. B. 3. ii for a further discussion regarding tree trimming.

Company and stakeholders. Therefore, witness Alvarez's proposals should be rejected (Robinson, 5T 2716-18).[48]

The Company further notes that invitations for the Commission to create a new type of "contested case proceeding, with discovery" (reflected at PFD, p. 190) also raises legal concerns. The present process complies with the law by allowing for comments on the Company's plan, but there is no legal authority to conduct "joint planning" as MNSC suggested, or for the Commission to order the Company to adopt a distribution plan. Even the statutory authority regarding generation planning is strictly limited to considering the utility's plan, and not a third party's alternative plan.[49] Our Supreme Court aptly described the bounds of utility regulation in *Union Carbide v. Public Service Comm*., 431 Mich 135; 428 NW2d 322 (1988) as follows:

> The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions. "It must never be forgotten that while the State may regulate with a view to enforcing reasonable rates, it is not the owner of the property of public utility companies and is not clothed with the general power of management incident to ownership." [citations omitted].[50]

It is also established law that:

> Customers pay for service, not the property used to render it. Their payments are not contributions to depreciation or other operating expenses or to capital of the company. By paying bills for service they do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company.

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[48] Various intervenors also suggested a series of conceptual proposals relating to distribution infrastructure that are incorrect or problematic on their face, or lack sufficient detail to be even thoroughly considered. Therefore, these proposals (presented in table form) should be rejected (Robinson, 5T 2721-23).

[49] MCL 460.6t(8) plainly states that the "commission shall approve *the integrated resource plan* under [MCL 460.6t(7)] if the commission determines all of the following . . . ." (Emphasis added). Thus, there is only "the integrated resource plan," which is the utility's proposed integrated resource plan.

[50] See also *Ford Motor Co. v. Public Service Comm*, 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) ("The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best."); *Consumers Power Co, Public Service Comm*, 189 Mich App 151, 180; 472 NW2d 77 (1991) ("To the extent that the PSC actually ordered Consumers to enter, or not enter, into any particular contract, it exceeded its authority").

[*Bd of Public Utility Comm'rs v New York Telephone Co*, 271 US 23, 32: 46 S Ct 363; 70 L Ed 2d 808 (1926) (emphasis added).]

Therefore, the suggestion that the DGP should be subjected to a litigated proceeding should be rejected.[51]

The PFD also suggests that the Company does not properly consider affordable and reliable service for its customers (e.g., PFD, pp 188-189). To the contrary, the Company encourages customer and stakeholder input and has many existing touchpoints and communication channels with customers where their needs, wants, and concerns are gathered (examples of customer outreach efforts are outlined in Ms. Crozier's testimony, 5T 2228-30).

In addition, the Company's capital investments in this case, as in previous cases, are based on long-term distribution planning processes that identify customer needs and develop and prioritize projects that provide customer benefits of improved safety and reliability in the near term, and lay the foundation for the long-term changes of increased electrification and DER adoption (Robinson, 5T 2693; Exhibit A-23, Schedule M7).[52] In 2022, the Company continued to focus on strategic investments, and was able to successfully invest over $700 million of strategic capital, exceeding the $696 million forecast in Case No. U-20836. For 2023, the Company forecasts $811 million of strategic capital, which is $5 million less than the $816 million forecast in Case No. U-20836. The change is driven by the increased focus on the need to expand the project portfolio in the Infrastructure Redesign and Modernization pillar, as well as increased investments in the 4.8kV

[51] The same response generally applies to CEO's proposal that the Commission not approve the Company's rate increase until after the Company's next distribution grid plan is developed through litigation (CEO Initial Brief, pp 27-30). Moreover, CEO suggests no legal basis for this proposition. The record demonstrates the need for significant grid investment. CEO does not contend otherwise, but instead acknowledges that "CEO are not opposed to any particular projects the Company propose," and "CEO do not take a position on particular spending proposals the Company has offered in this case." (CEO Initial Brief, pp 9, 29). It is also axiomatic that the Company is entitled to recover its costs of investments to provide utility service.

[52]The Company filed its most recent DGP on September 29, 2023 in docket U-20147.

Circuit Automation program, and a reduction in Infrastructure Resilience and Hardening (Miller, 5T 2850-51; Exhibit A-23, Schedule M2).

Improving grid reliability is a key focus for strategic investments. Reliability is measured by several metrics, including the all-weather System Average Interruption Duration Index (SAIDI) and by SAIDI-Excluding-Major Event Days (MEDs). DTE Electric fell in the fourth quartile for all weather SAIDI in several of the past years, but the Company's SAIDI Ex-MED was on the border of the 2nd quartile in 2021 and was trending towards the 2nd quartile for 2022 (Robinson, 5T 2690, Figure 2). When excluding the impact of abnormally severe weather events, such as the extreme weather in the summer of 2021, SAIDI Ex-MED demonstrates that the day-to-day reliability of the Company's system has increased based on recent investments and is on track to achieve second quartile performance by 2025 (Robinson, 5T 2688-92).

Much of the PFD's commentary and recommendations arise from overstated and inaccurate criticisms of the GPM and suggested alternatives by intervenors. For example, AG/MNSC witness Alvarez asserted that the Commission should order "risk-informed benefit-cost analyses," which he described as "[i]n most respects . . . the same as benefit-cost analyses: a simple comparison of the benefits of a project or program to customers over an investment's expected lifetime (depreciation period) to the costs of a project or program to customers (defined as the present value of associated revenue benefits over time)."(6T 3346) He further proposed a formula for a "risk-informed benefit calculation," that purportedly can be used to estimate the value of risk reduction to customers and asserted that the "calculation is simple and intuitive." *Id.* To estimate the benefit (in dollars) of a reduction in the likelihood of an adverse event (i.e., a risk) delivered by an investment (let's call it investment 'a'), one need only multiply the reduction delivered by investment (a) in the likelihood (percent) of an adverse event (b) by the consequence (in dollars)

associated with adverse event (b) if it occurs." (Alvarez, 6T 3346).[53] He further recommended that the Commission "order that risk-informed benefit-cost analyses be completed on any distribution investment plan project or program with capital spending in excess of $100,000, and to include those analyses in plan workpapers . . . [and] that risk-informed decision support be used to select the projects and programs for a distribution investment plan from a portfolio of potential investments" (Alvarez, 6T 3353).

First, the Company clearly identifies the process by which projects get approved (Miller, 5T 2842-2844); which the ALJ clearly acknowledges in the PFD (PFD pp.135-136). This process includes extensive review of planned projects and alternatives by Company SMEs, engineers, planners, and management. After projects are approved as necessary to meet customer and gird needs, they are then evaluated in the GPM.

The Company disagrees with witness Alvarez' assessment of the need for his "risk-informed" process for two primary reasons. First, it is unnecessary for the Commission to order the Company to perform the suggested analysis because the Company already performs risk-informed analysis as part of its GPM that the Company developed to assess the impact that strategic investment programs and projects are expected to have on the grid in order to meet customer needs, as indicated above. Second, Mr. Alvarez provided no evidence that his proposed equation is generally accepted best practice or better than the Company's current risk-informed analysis. Mr. Kryscynski provided extensive direct testimony on how the Company uses the GPM to evaluate its capital and spending programs, as well as a further example on rebuttal regarding how strategic investment programs are evaluated against seven impact dimensions (3T 385-95, 426-27).

[53] Mr. Alvarez offered support for his proposed formula that does not include the formula, but instead only presents steps to build a cost-benefit approach to identify and assess risks (Kryscynski, 3T 424-25; Exhibit A-44, Schedule II1).

Mr. Alvarez attempted to support his equation by asserting that "benefits" are "not always easy to calculate" (6T 3346). That is true, at least to some extent (for example, regarding improvements to public safety), but Mr. Alvarez's proposed formula does not improve the situation, nor does he suggest a method for converting such benefits to monetary amounts. Moreover, attempting to provide a monetary amount for each impact dimension would create more ambiguity by introducing a new variable that is inherently subjective. For example, reducing wire downs is a safety improvement, but there is no method or industry best practice for assigning a dollar value to reduced wire downs. The Company could assign a value (as could others and we could argue about them), but ultimately there is no hard data to conclusively establish that any assigned dollar amount is correct. Thus, there would be no value to the Company or its customers, and the Commission would simply waste its resources chasing something that is inherently indeterminate (Kryscynski, 3T 427-28).

Despite the evidence, the PFD quoted a portion of MNSC's brief (essentially asserting that the GPM ranks investments, but does not say whether the value exceeds the costs, or when to make the investments), and contends that this "could well serve as a motto for the deficiencies in this case" and "DTE has failed to provide any meaningful response to this critique" (PFD, p 188).

The Company disagrees. MNSC's criticisms of the GPM lack merit as indicated above and further explained on the record.[54] MNSC's argument (which the PFD improperly suggests could serve as a "motto" against the GPM) neglects that the same and additional criticisms could be said of proposed alternatives including their own. For example, as indicated above, Mr. Alvarez's proposed formula does not improve the situation because he does not suggest a method for

[54] For example, Mr. Kryscynski provided extensive direct testimony on how the Company uses the GPM to evaluate its capital and spending programs, and a further example on rebuttal regarding how strategic investment programs are evaluated against seven impact dimensions (3T 385-95, 426-27).

converting benefits to monetary amounts and attempting to provide a monetary amount for each impact dimension, e.g., safety benefits, would create more ambiguity by introducing a new variable that is inherently subjective.

Therefore, the Commission should look past the PFD and MNSC's theoretical and unsupported suggestions, and instead follow the record which demonstrates the Company properly uses the GPM to prioritize projects and identify benefits in the real world. The Company also provided additional extensive direct testimony and exhibits that supported each strategic project and program (for example, Exhibit A-23, Schedules M4, M5, and M6) which include a specific purpose and necessity for each strategy program and project. Further discussion is provided below where it is best understood in context.

ii. Emergent Replacement – Storm and Non-Storm

The Commission previously "direct[ed] DTE Electric, in its next electric rate case filing, to provide a detailed description of each type of expenditures assigned to the emergent replacements category" (May 8, 2020 Order in Case No. U-20561, pp 86-87). Accordingly, Mr. Hill explained that the Company tracks Emergent Replacements in three major categories: (1) Storm (investments required to restore the overhead and underground distribution systems, the subtransmission system, and substations from damage that occurs during storms);[55] (2) Non-Storm (capital replacements required to return the overhead and underground distribution systems, and subtransmission electrical system to restore power and/or return to normal operating configuration during non-storm conditions);

[55] A storm is declared when the number of outages exceeds 340 and the number of circuits impacted exceeds 125 (typically equivalent to 25,000 customers) (Hill, 5T 2737).

and (3) Substation Reactive (investments required to perform emergency replacements for substation equipment). (Hill, 5T 2737, 2742, 2752).[56] The PFD states:

> No party took issue with the company's reclassifications, but in light of DTE's determination that it cannot distinguish between replacements of failed equipment made during emergent repair work, and replacements made for efficiency or other reasons during that work, the classifications lack the degree of separation the Commission would prefer. [PFD, p 195.]

The Company has responded to the Commission as well as practicable. The Commission previously ordered that "DTE Electric Company shall begin tracking equipment identified as imminent failure (near failure but has not failed) and exclude those costs from the emergent replacements' capital program" (November 18, 2022 Order in Case No. U-20836, p 485). The Company believes that it can comply with this directive in the Substation Reactive category, where the Company performs predictive and preventive maintenance on equipment such as transformers, 120kV disconnects, 24kV/40kV breakers, distribution breakers, and regulators. The process of identifying these expenditures and tracking them began in 2023**.** The Company is not able to strictly comply with this directive in the Storm and Non-Storm categories, however, because the Company is not able to track, in all circumstances and for all equipment classes, equipment deemed to be at risk of imminent failure separate from equipment that has already failed. For example, a lineman dispatched to fix one problem, such as a broken insulator, at a location might observe a second problem, such as a rotting cross arm, after arriving at the location. The linemen would then replace the two pieces of defective equipment.

[56] DTE Electric's Initial Brief, pp 46-49, explained that Emergent Replacement investments, Storm and Non-Storm, are essential to providing safe (e.g., responding to downed wires) and reliable power to customers. The Company forecasts Storm expenditures of $177 million for 2022, $221 million for 2023, and $227 million for 2024, based on a five-year (2017-2021) inflation-adjusted historical average, consistent with the methodology approved in the Commission's orders in Case Nos. U-20162, U-20561, and U-20836. The Company forecasts non-storm investments of $265 million for 2022, $183 million for 2023, and $188 million for 2024. The 2023 and 2024 forecasts are based on a five-year (2017-2021) inflation-adjusted historic average, consistent with the methodology approved in the Commission's orders in Case Nos. U-20162, U-20561, and U-20836. The 2022 non-storm forecast is higher than the five-year inflation-adjusted average ($177 million) due to several factors driving higher actual costs.

This type of work in not formally planned and decisions are made in the field. It would be highly inefficient and nearly impossible for the lineman to separately track these replacements and their associated work (Hill, 5T 2758-59).

AG witness Coppola recommended that the Commission "remove $18,779,000 for the 11 months ending November 2023 and $21,975,000 for the 12 months ending November 2024, for a total removal of $40,754,000" from the Company's forecasted emergent replacements capital expenditures (Coppola 6T 3644), due to his disagreement with the Company's normalization adjustment. The PFD states:

> On this record, in the absence of any meaningful analysis from DTE, this PFD finds Mr. Coppola's recommendation to use a five-year average without the inflation-normalization adjustment provides a better, more reasonable estimate of what DTE's 2021 costs would have been under a variety of emergent conditions. DTE's filing in this case alone indicates that DTE has invested billions of dollars in capital assets including not just distribution system capital but IT capital as well. [PFD, p 204.]

To the contrary, the Company provided a "meaningful analysis" explaining that prior years' expenditures must be expressed in a constant-dollar denomination (in this case, 2021 dollars) because the value of a dollar changes over time due to inflation (Miller, 5T 2864-65), and the time value of money is a core principle of finance. The PFD's recommendation arbitrarily drives down the recommended revenue requirement despite the Company's investments in providing utility service and despite solid reasoning to the contrary. Furthermore, the recommendation fails to acknowledge that the Commission previously approved the Company's normalization practice (Case No. U-20561, May 8,2020 Order, p 86) and most recently agreed with, and found appropriate, "the [same] ALJ's recommendation for the continued use of the five-year average in determining this category of expenditures, along with the inflationary adjustment to historical data" (Case No.

U-20836, 11/18/2022, p 63). The AG also acknowledged that "the Commission accepted this approach with regard to emergent capital expenditures in Case U-20836" (AG Initial Brief, p 35).

AG witness Coppola proposed reductions in capital expenditures of $13,383,000 for the 11 months ending November 2023, and $28,808,000 for the projected test year due to tree trimming reducing power outages caused by trees (6T 3689). The Company disagrees because the proposal is duplicative. The Company included cost avoidance associated with reduced equipment failures from the tree trimming surge in Exhibit A-12, Schedule B5.4, page 1, line 6, in accordance with past practice (Miller, 5T 2866-67). In addition, Mr. Miller highlighted that Mr. Coppola withdrew a similar proposal in Case No. U-20836 that was based on the same type of evidence offered by him in the instant case (Miller, 5T 2866-67).

The PFD nevertheless "concludes that Mr. Coppola's adjustment should be adopted; the confusion regarding the adjustment on line 6 is entirely of DTE's making" (PFD, p 206). The Company disagrees because it has proven its position on the record as discussed above. The PFD's suggestion that the Company should instead be punished for allegedly causing "confusion" is contrary to law[57], unfounded in light of the record and otherwise inappropriate as the AG previously conceded the same issue.

The PFD further asserts that "DTE neglected to reflect O&M savings associated with the tree trimming surge program, making it more likely it omitted the savings from its capital cost analysis as well" (PFD, pp 207-208). The record instead reflects that the Company corrected an oversight when it was discovered.[58] To the extent this is relevant, it demonstrates that the

[57] Michigan's Constitution requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, Art 6, § 28

[58] AG witness Coppola recommended that the Commission "remove $15.9 million in cost savings from the Company's forecasted O&M expense" due to savings from the surge (6T 3775). The $15.9 million includes three expense items:

Company's numbers (after further scrutiny and any appropriate correction(s) in response to indicated concerns) are "likely" to be accurate. The PFD's contrary speculation cannot support a decision, [59] and suggests drawing inferences that are contrary to the record evidence, which would be unlawful.[60]

Therefore, the PFD/AG's proposed disallowances should be rejected.

iii. Customer Connections, Relocations & Other Capital Investments

Investments in this category are reasonable, prudent, and should be approved.[61] AG witness Coppola proposed that "[g]iven the variability" in Small Load Growth projects, Customer Connections, and Relocation projects, the best approach is to use a historical average to forecast capital expenditures (6T 3645, 3650). The PFD agreed (p 211, pp 213-14). The Company disagrees for several reasons, first noting that the PFD recommends inconsistent treatment of investment categories as Mr. Coppola did not propose the same treatment for every item in this category. Rather, Mr. Coppola selected only line items that would lower revenue requirement for use in his historic average, with respect to any historic averages that would increase revenue requirement Mr. Coppola proposed one year plus inflation. The Company forecasted most of the capital

(1) Tree Trim Reactive, (2) Tree Trim Storm, and (3) Distribution Operations Storm & Trouble. The Company disagrees with the AG regarding Tree Trim Reactive because the savings are already accounted for in Exhibit A-22, Schedule L1, line 4. The Company agrees with the AG that O&M should be reduced by savings from Tree Trim Storm ($3.6 million) and Dist. Ops. Storm & Trouble ($2.7 million). These items were inadvertently omitted from the O&M calculation, and this has been corrected by a $6.3 million O&M reduction (Hartwick, 5T 2162-63; Exhibit A-13, Schedule C5.6 Revised, page 1, line 20).

[59] *Star Steel v USF&G*, 186 Mich App 475, 481; 465 NW2d 17 (1990); *see also, Skinner v Square D Co*, 445 Mich 153; 516 NW2d 475 (1994).

[60] *White v Revere Copper & Brass, Inc,* 383 Mich 457, 462-63; 175 NW2d 774 (1970).

[61] These investments include six major subcategories: (1) Customer Connections and New Load; (2) Relocations; (3) Electrical System Equipment; (4) Normal Retirement Unit Change-out (NRUC) and Improvement Blankets; (5) General Plant, Tools & Equipment and Miscellaneous; and (6) Public Lighting Department Project (Hill, 5T 2760). Further sub-subcategories and other details are discussed at Hill, 5T 2760-66.

expenditures in this category of investment using prior years investments plus inflation, consistent with approaches utilized in Case Nos. U-20162, U-20561, and U-20836, with only specific projects that were not forecasted this way, e.g., Gordie Howe International Bridge (GHIB) which was based on the project's schedule (5T 2858). Mr. Coppola proposed a five-year average for certain line items in Case No. U-20836, but now proposes a three-year average (and even then, not the same years) to different line items in this case, without explanation for either the different methodology or different line items. Mr. Coppola altered his methodology despite the fact that the historic values used in his calculations did not change between U-20836 and U-21297 for the projects he selected in U-20836. Notably, using the methodology proposed by Mr. Coppola in U-20836 would increase the capital expenditures forecast if applied in this case (Miller, 5T 2858-59, 2870-72; Exhibit A-39, Schedule DD2).

Customer Connections, Relocations, and other investments, which are driven by customer requests, have shown consistent year-over-year growth in recent years (Exhibit A-39, Schedule DD3). The Company has consistently used the prior-year-plus-inflation forecasting method which has resulted in reasonable and accurate projections of capital actually spent (in fact, it has often been understated). In contrast, Mr. Coppola's inconsistent use of varying averaging methods for different sub-categories of expenditures would not allow the Company to consistently plan its capital investments from rate case to rate case. The methodology that Mr. Coppola crafted just for this case would also significantly under-forecast the cost that the Company is likely to incur to provide these services to its customers. The PFD appears to have misunderstood this point. It is not that the Company has been unable to plan using the prior consistent methodology; instead, planning

would be impaired using Mr. Coppola's shifting methodologies.[62] Therefore, the Commission should reject the PFD/AG's proposed disallowance, and approve the funding levels requested by the Company (Miller, 5T 2873-74).

More specifically regarding Small Load Growth projects, Mr. Coppola recommended that Commission "remove $2,955,000 for the 11 months ending November 2023 and $3,354,000 for the 12 months ending November 2024, for a total removal of $6,309,000 from the Company's forecasted capital expenditures" (6T 3646). The Company disagrees with the AG's methodology as discussed above. Also, even assuming that a multi-year average should be used (which it should not), Mr. Coppola performed the calculation improperly by not using a normalization adjustment. In addition to the discussion above in emergent replacements, see the May 8, 2020 Order in Case No. U-20561, p. 86 ("Adding inflation to the five-year historic actual spend is appropriate for calculating the starting point for normalized expenditures"). Therefore, the Commission should reject the PFD/AG's selective use of an historic average. If the Commission does choose to use such a methodology, however, then it should be applied with a normalization adjustment, consistent with the May 8, 2020 Order in Case No. U-20561, as shown in Exhibit A-39, Schedule DD4 (Miller, 5T 2875-76).

Regarding Customer Connections projects, Mr. Coppola recommended that the Commission "remove $24,645,000 for the 11 months ending November 2023 and $20,507,000 for

[62] The Company further notes that the PFD may have been confused by a flawed argument by the AG that is refuted by the actual evidence in the case. The AG's Initial Brief, pp 38-39, asserted that "Mr. Miller's claim is meritless" because he allegedly could not provide any evidence in response to the AG's request "to provide evidence that in planning for capital expenditures for 2021 through 2023, the Company used the supposedly erratic amounts approved by the Commission." To the contrary, the Company used actual dollars invested. Those dollars met or exceeded the amounts approved for rate base in prior cases. It is Mr. Coppola's methodologies that are erratic. The referenced discovery response (Exhibit AG-1.78, pp 7-8) further reflects how the Company is able to plan investments based on Commission-approved rates that include elements that are developed on a consistent basis from rate case to rate case.

the 12 months ending November 2024 for a total amount of $45,132,000 from the Company's forecasted capital expenditures" (6T 3649), reasoning that "[a]s a result of the higher interest rates, new housing starts have declined significantly in 2023 and will likely continue into early 2024 before rebounding. As a result, customer connections will decline from the high level seen in 2021" (6T 3648).

The Company disagrees with Mr. Coppola's methodology as indicated above, further noting that he switched from 2020 to 2022 for Small Load Growth projects (6T 3645), to 2019 to 2021 for Customer Connections (Net of CIAC) (6T 4648). He then considered the single variable of housing starts as a proxy for forecasting Customer Connections, which is not a relevant consideration because this category of customer requested investments includes many types of customer needs, not just those reflected in the number of housing starts (Hill, 5T 2760; Miller, 5T 2877-78). Based on Mr. Coppola's methodology, the Company would have experienced a decline in category expenditures in 2022 (corresponding to the decline in housing starts), but actual expenditures increased from $93.3 million in 2021 to $106.7 million in 2022, which is a 13.7% *increase* rather than the 8.7% *decrease* Mr. Coppola used in his calculations to forecast 2023 and 2024 housing starts and expenditures (Exhibit A-39, Schedule DD3, line 5).

The PFD misses the relevant point and relies upon flawed methodology. The point is not whether "there is reason to believe" that there will be a decrease in customer connections (PFD, p 213, further quoted above). Rather, the point is that Mr. Coppola calculated a decrease when there actually was an increase, so there is no valid reason to believe that his methodology is accurate. Therefore, the Commission should reject the PFD/AG's proposed disallowance as it is inconsistent

with the record and based upon flawed methodology and approve the Company's forecasted amount (Miller, 5T 2878-79).[63]

Regarding Relocation projects, Mr. Coppola switched back to a three-year average of 2020-2022 and recommended that the Commission "remove $6,661,000 for the 11 months ending November 2023 and $3,351,000 for the 12 months ending November 2024 for a total removal of $10,012,000 from the Company's forecasted capital expenditures" (6T 3651). The Company disagrees with Mr. Coppola's methodology as indicated above. Applying a selectively chosen historical average to a varying section of line items would not allow the Company to plan its capital investments consistently. If the Commission does choose to accept the selective use of an historic average, then the average should at least be properly calculated using a normalization adjustment as shown in Exhibit A-39, Schedule DD5 (Miller, 5T 2880-81).

iv. Strategic Capital

Strategic Capital projects and programs include work that the Company performs to improve safety, reliability and operability, and grid modernization. These investments are subcategorized into three areas or pillars: (1) Infrastructure Resilience and Hardening; (2) Infrastructure Redesign and Modernization; and (3) Technology & Automation.[64]

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[63] *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).

[64] ***Infrastructure Resilience and Hardening***. These projects and programs focus on replacing aging infrastructure at risk of failure, hardening the system, and addressing areas of the system with known poor customer reliability. Exhibit A-12, Schedule B5.4, page 8 provides details, with additional details at Exhibit A-23, Schedule M4.

Infrastructure Redesign and Modernization. These projects and programs make more fundamental changes to the electrical system, such as conversion of the 4.8kV system and upgrades to the subtransmission system.

ABATE witness York argued that DTE's proposed spending on Strategic Capital Programs includes significant levels of capital expenditures for projects that are not expected to be placed in service until after the end of the projected test year and recommended that the Commission allow only the projected capital expenditures associated with projects that are expected to be in service during the bridge period and projected test year. This results in a capital expenditure reduction of $1.109 billion relative to the amount proposed by the Company. (York, 4T 1139-40).

The Company disagreed with ABATE's suggestion that the Company should be disallowed rate recovery for projects with in-service dates outside the test year because this would be inconsistent with legal and regulatory practice. Project costs can be included in rate base if they are deemed reasonable and prudent regardless of whether they will be in service in the projected test year.[65] Under well-established accounting practice, and in compliance with the Commission's May 10, 1976 Order in Case No. U-4771, utilities may include construction work in progress (CWIP) in rate base because the revenue requirement is generally offset by an Allowance for Funds Used During Construction (AFUDC). AFUDC is applied to projects greater than $50,000 and lasting more than six months, with an exception for environmental and other specifically ordered

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Exhibit A-12, Schedule B5.4, pages 9-11 provide details, with additional details at Exhibit A-23, Schedule M5.

Technology & Automation. These projects and programs are tightly linked to the grid modernization process and include investments that develop capabilities in observability, analytics and computing, controls, and communications. Exhibit A-12, Schedule B5.4, page 12 provides details, with additional details at Exhibit A-23, Schedule M6 (Miller, 5T 2841,2846-47, 2853, 2855, 2857-59).

[65] The Court of Appeals previously rejected the contention that the Commission has no authority to apply anything other than the "used and useful" test in setting rates. *ABATE v Public Service Comm*, 208 Mich App 248, 258-59; 527 NW2d 533 (1994). The Commission is not bound to apply any particular formula or use any specific method in setting rates. *Id*; *Detroit Edison Co v Public Service Comm*, 127 Mich App 499, 524; 342 NW2d 273 (1983); *Residential Ratepayer Consortium v Public Service Comm*, 239 Mich App 1, 6; 607 NW2d 391 (1999).

projects.[66] Also, project completion dates are often based on the final steps of a project, and customers receive the benefits of the work done before these final steps. For example, in conversion work customers benefit from reduced trouble events, wire downs, and improved reliability long before the final step of decommissioning an old substation. Therefore, the Commission should reject ABATE's proposed disallowance (Deol, 2T 200; Uzenski, 5T 1512-13, 1572-73; Miller, 5T 2884-86).

The PFD states:

> This PFD concludes that Ms. York's recommendation is reasonable, and that projects that are not in service by the end of the test year should be removed from rate base, along with the corresponding AFUDC offset, and not approved by the Commission. While Ms. Uzenski correctly points out that if these capital projects are excluded, the offsetting AFUDC adjustments should also be excluded, this PFD finds this approach preferable. The enormity of the projects and dollar volume encompassed within these projects, which Ms. York measured as over $1 billion, and for which DTE's own accounting does not seek any revenue in this case, argue in favor of excluding them from rate base, including projected CWIP. [PFD, pp 219-20.]
>
> * * *
>
> While this PFD understands that DTE would rather obtain Commission approval for projected spending well in advance of the project in-service dates, as Ms. York testified, some of those projects will not be in service for many years, and review of those projects is not necessary to the primary task at hand, reviewing DTE's requested revenue increase, cost of service allocation, and rate design. DTE should instead be able to file such projects and associated costs separately within its rate case filing, as informational for the parties, similar to its filing of the DGP in this case and its filing of a five-year IT plan in its last rate case. The Commission has also provided an alternative expedited process for DTE to obtain stakeholder review of proposed pilot programs [in the February 23, 2023 Order in Case No. U-20898]. [PFD, pp 221-22.]

[66] If the Commission were to accept ABATE's proposition, then then the impact could be material, and the Commission should order a corresponding adjustment (reduction) in pre-tax AFUDC in projected net operating income to offset the removal of projects from approved rate base (Uzenski, 5T 1573).

As noted in the PFD, long-term projects may be included in rate cases to explain the Company's plans before large amounts of money are invested. The Company also seeks approval to include these projects in rate base, however, projects not in service in the projected test period have no net revenue requirement because of the AFUDC offset. As discussed above, disallowances of projects with an AFUDC offset have no impact to the amount of rate relief requested or approved. The correct result can be achieved by simply not reducing the Company's requested rate base and leaving the full AFUDC credit as filed in projected net income. (5T 1512-1513, 5T 1572-1573, A-13, Sch C11.1)

The Company also asserts a continuing exception to the PFD's inconsistencies and suggestions that are contrary to well established law and procedural requirements. On the one hand, the PFD expressly declines to decide certain issues, reasoning for example that they are "not necessary to the primary task at hand" as indicated in the quote above. On the other hand, the PFD then goes on to suggest how the issues should be decided in future cases), essentially suggesting what the issues will be in future cases and a presumption against the Company in how they will be decided. This practice is contrary to the limited scope of a PFD under MCL 24.281, the statutory purpose of the instant proceeding,[67] and threatens to violate axiomatic regulatory practice (for example, each case must be decided on that case's record using a preponderance of the evidence standard as discussed in section II) and fundamental due process.[68] Such suggestions cannot form the basis for a lawful Commission Order.

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[67] See generally MCL 460.6a.

[68] 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 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.

Staff recommended "a 10% reduction be applied to all Strategic Capital programs, excluding the strategic and service undergrounding pilot and the CODI [City of Detroit Infrastructure] projects, in order to protect ratepayers from potential underspending in the projected test year" (Evans, 7T 4416), reasoning that "[t]he Company has yet to demonstrate that it can project a certain amount of capital expenditures for the test year for Strategic Capital programs, and then subsequently spend that amount" (Evans, 7T 441511).

The Company explained that it understands Staff's concern but remains confident that it will be able to deliver on the higher levels of projected investment. The Company has taken several steps to ensure that the requested strategic capital is invested in strategic projects and programs, including (1) increasing labor force, (2) leveraging partnerships, (3) strengthening project management oversight, and (4) strengthening supply chain oversight. These steps have been successful, as reflected by the Company forecasting $696 million of strategic capital in Case No. U-20836 for 2022, and actually investing $712 million in 2022. The Company is showing its ability to execute strategic investment to improve customer service consistent with its forecasting, so Staff's proposed 10% adjustment should not be adopted (Miller, 5T 2851-53, 2882-83; Exhibit A-39, Schedule DD6).

The PFD states:

> After reviewing Mr. Miller's testimony and Schedule M1 in Exhibit A-23, this PFD concludes that DTE's strategic capital spending in 2022, which unexpectedly to DTE exceeded its Case No. U-20836 rate case target after the company's initial filing numbers were prepared, is insufficient to establish that the company can consistently meet its projected spending for these programs, given the history of underspending recited in part by Mr. Evans and by prior Commission orders including the January 31, 2017 order in Case No. U-20836 discussed above [sic, there is no such order]. [PFD, pp 223-24. Footnote omitted.]

The Company maintains its position for the reasons indicated above, further noting that its efforts have achieved success (as Staff acknowledged in its Initial Brief, p 34: "DTE has shown it

can forecast capital expenditures for Strategic Capital for a bridge period [referencing 2022] and then spend it"). The record further reflects that 2021 was one of the worst storm years in the Company's history, resulting in higher than projected DO investments largely driven by emergent replacements, but the Company was still able to invest all of the projected strategic capital. Therefore, the PFD/Staff's proposed 10% disallowance is unnecessary and inappropriate. (Miller, 5T 2847-49; Hill, 5T 2739-41).

In addition, the PFD proceeds to recommend additional overlapping disallowances based upon a myriad of arguments that DTE Electric's projected spending is not reasonable and prudent (PFD p. 224). The PFD further inappropriately recommends projects not in service during the projected test period, which are included in CWIP, but have no net revenue requirement because of the AFUDC offset, to be "excluded from rate base," apparently neglecting that CWIP is in rate base, as reflected in Exhibit B of the PFD. The Company disagrees that the PFD's proposed disallowances are reasonable or just and therefore the Commission should reject these recommendations.

v. Specific Strategic Capital Investment Programs

DTE Electric's Strategic Capital investments are grouped in three pillars: 1) Infrastructure Resilience & Hardening, 2) Infrastructure Redesign and Modernization, and 3) Technology and Automation, as indicated above and further discussed below.

a. Infrastructure Resilience & Hardening.

Infrastructure Resilience & Hardening includes projects and programs focused on near-term grid infrastructure investments to harden the system against increasingly frequent and more severe weather including high winds and storms, addressing frequent outage circuits, and replacing aging

infrastructure. The Company projects capital costs associated with these projects of $692.3 million for 23 months ending November 30, 2023, and $244.5 million for the projected test year (Elliott Andahazy, 3T 506; Exhibit A-12, Schedule B5.4, page 8; Exhibit A-23, Schedule M4). The Company plans to invest in 30 different programs in this category, including the programs discussed specifically below.

The PFD was generally critical of the Company's support for its programs based on arguments that some alternative might be preferable. AG/MNSC witness Stephens suggested that he performed a "risk-informed benefit cost analysis" based on AG/MNSC witness Alvarez's formula (Stephens, 6T 3387). As indicated above, the Company disagrees with Mr. Alvarez's proposed formula and related propositions, in part because putting a monetary value on certain benefits like safety is inherently subjective.

Mr. Stephens indicated a belief that Occupational Safety and Health Administration (OSHA) recordable incidents are the driver to measure the success of capital investments associated with safety (e.g., Stephens, 6T 3396). The Company disagrees because OSHA recordable incidents are a metric used for employee injuries that meet a certain threshold. They are not a measure of public safety risk reduction. OSHA recordables are also a lagging metric that measures safety incidents after they happened, instead of a leading metric to proactively prevent accidents and injuries. Furthermore, many OSHA recordable incidents are unrelated to infrastructure investment, such as an employee twisting an ankle in a customer's yard, injury from a motor vehicle accident or a cut incurred while slicing a cable jacket. The Company strives to proactively improve the safety of its infrastructure for both the public and its employees, including investments for safety not related to OSHA recordable incidents. Examples include the Port Huron project, which had exposed energized equipment that caused a safety and operating concern (Exhibit A-23, Schedule M4), and

the Pontiac Vaults, which "[d]ue to the confined space in the vaults, there is also a shock hazard to personnel entering the vaults" (Exhibit A-23, Schedule M7, section 8.19, page 210). The Company considers customer and employee safety to be a high priority and will continue to proactively invest to improve safety. Requiring OSHA recordable incidents to have occurred prior to implementing safety investments (as Mr. Stephens suggests) would not be prudent. In addition to failing to be proactive, using the proposed measure in Mr. Alvarez's formula (as Mr. Stephens suggests) would also understate the benefits of improvements, and the use of that formula (as Mr. Alvarez suggests) would lead to safety improvements not being made (Elliott Andahazy, 3T 566-68, 589).

1. Substation Risk.

The Company's Distribution Grid Plan (DGP; Exhibit A-23, Schedule M7) proposes to replace equipment with high potential for stranded load and/or compromised substation asset condition. As indicated above, the PFD was persuaded by criticisms regarding the DGP. The Company disagrees for a number of reasons. In this specific context, Mr. Stephens asserted: "Unless and until the Company produces a risk-informed benefit-cost analysis for every substation risk reduction project, or for its various substation equipment replacement programs, I recommend recovery of substation risk cost be disallowed in full and removed from future capital spending plans" (Stephens, 6T 3391).

The Company disagrees because it already performed a risk-informed benefit analysis for Substation Risk projects using the GPM, as indicated above. In addition, there are errors and deficiencies in Mr. Stephens' application of Mr. Alvarez's formula. For example, Mr. Stephens suggested that he performed a robust suite of analyses. (6T 3387: "Every time I have completed this analysis, the premature replacement of equipment operating safely and reliably, just because it is old, is not cost effective.") Yet, his testimony only shows one attempt at completing the analysis

on circuit breakers, as further discussed below. He also acknowledged that "[t]ime constraints prohibited [him] from evaluating all these projects in the instant Application in detail" (Stephens, 6T 3386). Mr. Stephens did not support his speculation that the Company replaces equipment "just because it is old," and the record shows he is incorrect in this regard. The DGP lays out specific replacement factors for various pieces of substation equipment. For example, there are four criteria for replacing circuit breakers (Interrupting medium, High O&M costs, Unavailable Parts, and Known Performance Issues), none of which just depend on the age of the equipment (Exhibit A-23, Schedule M7, page 168). (Elliott Andahazy, 3T 569-70, 574).

Mr. Stephens suggested that substation risk projects are not worth their costs because "[he] completed a risk-informed benefit cost analysis of the type Mr. Alvarez describes in his testimony on the breaker replacement program in the Company's DGP." (Stephens, 6T 3386-87). Mr. Stephens did not offer any support for the parameters that he used in Mr. Alvarez's formula, nor did he fully consider all relevant factors. His analysis is incomplete, however, because there is more to the substation risk project than breaker replacement, as indicated above. In addition, Mr. Stephens admits that the program "replac[es] a variety of equipment types in 'high risk' substations, including disconnect switches, circuit switchers, circuit breakers, and voltage regulators." (Stephens, 6T 3386). For example, failure of a breaker with no available spare parts could lengthen customer outages and result in significant additional costs for the deployment of generators or portable substations to restore customers. Mr. Stephens also failed to consider the maintenance cost savings over time by replacing an obsolete oil-breaker with a modern breaker (Elliott Andahazy, 3T 571-72, 577).

Mr. Stephens asserted that, "Risk-informed cost benefit analyses are completely data-driven and represent the most objective foundation for decision-making available" (6T 3388-89). The

Company agrees in principle with the use of risk-informed data-driven analysis, which is why the Company uses the GPM, with factors including safety risk, avoided costs, load relief, and reliability improvements. In contrast, Mr. Stephens' analysis is incomplete and incorrect. He did not attempt to quantify any benefit other than reliability improvements, and other measures (such as safety improvements) cannot be objectively monetized. Therefore Mr. Alvarez's formula, and Mr. Stephens' application of it, are not "completely data driven." Mr. Stephens' application of the formula is entitled to no weight and should be rejected. There is no sound basis to disallow substation risk capital just because the Company did not perform the AG/MNSC's flawed analysis (Elliott Andahazy, 3T 572-73, 575, 577).

Mr. Stephens also failed to address any detail regarding the projects such as how substations are selected, potential failures or even the impact on customer reliability of those that have failed (reflected in Exhibit A-23, Schedule M4, pages 6-41; Exhibit A-23, Schedule M7, pages 232-40). He instead superficially mischaracterized the program as "premature equipment replacement" (Stephens, 6T 3385). Replacing equipment that has already failed, such as the Drexel and McGraw projects, and eliminating equipment that is a safety hazard, such as the Port Huron project, is not "premature equipment replacement." (Elliott Andahazy, 3T 575-77). As stated on page 237 of Exhibit A-23, Schedule M7 (in describing the historic flooding events in 2021 which impacted thousands of southeast Michigan residents as well as electric service and other infrastructure, "Two DTEE substations in Detroit, McGraw and Scotten, flooded as a result of this storm. The damage that resulted from multiple electrical faults caused by the flood left much of the equipment, including breakers, and buses unrepairable at McGraw." This is a clear indication that the equipment did, in fact, fail at McGraw and the Company was unable to repair said equipment.

In summary, Mr. Stephens did not evaluate substation risk projects, did not propose to disallow any specific project, did not provide support for the limited data used in his analysis, nor even dispute the Company's supporting documentation. Instead, he broadly proposed to disallow all of the entire program based on his defective application of Mr. Alvarez's flawed formula. His analysis fails to even recognize (let alone quantify) benefits such as safety improvements and replacement of failed equipment. Therefore, Mr. Stephens' proposed disallowance should be rejected (Elliott Andahazy, 3T 577-78).

MNSC's co-sponsored testimony broadly yet vaguely suggests alternative analyses and proposes massive disallowances. The Company attempted to unravel this and respond in rebuttal. Then MNSC largely abandoned and misconstrued its own witnesses' testimony criticizing the Company's rebuttal for pursuing tangents that MNSC raised while not addressing matters that MNSC's witnesses did not raise. As the Commission has previously 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 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.]

The PFD suggests that this argument is "seriously misleading" (PFD, p 229). To the contrary, the Company accurately pointed out that MNSC raised issues through intervenor testimony and the Company responded appropriately as well as practicable in the limited time available under the schedule. Then MNSC largely abandoned its prior position in favor of

alternative arguments. The Company maintains its objection to this lack of adherence to well established procedure[69] and misapplication of the burden of proof.

The PFD states:

> Consistent with this PFD's discussion above, and Ms. York's testimony, this PFD notes that the Chestnut, Apache, and McGraw projects will not be completed within the test year, as shown on lines 10, 12, and 15 of Schedule B5.4, page 14, and consistent with this PFD's conclusion in subsection a above, should be excluded from rate base and not approved.
>
> This PFD further finds that MNSC's analysis is persuasive that DTE has not justified this program generally. . . . Since MNSC is only seeking to exclude the bridge and test period costs, and most of these costs are associated with projects that will not be completed within the test year, this PFD finds that DTE should be cautioned that if it seeks to recover costs for these or other projects in the future, it must have objective analyses that supports its decision-making, and be prepared to show its work . . .
>
> [After indicating that historical costs for certain projects should be approved] This PFD concludes, however, that the Substation Risk: Flood Defense program should not be approved . . . [because] a review of the documentation provided for this project also shows inconsistencies. [PFD, pp 231-32.]

As discussed above, Company projects not in service in the projected test period are included in CWIP but have no net revenue requirement because of the AFUDC offset. Exclusion from rate base is not appropriate because they are included in CWIP, as indicated in Exhibit B of the PFD.

The Company maintains it properly supported its projects in this category, as discussed above. With respect to the only historical cost that the PFD recommended the Commission disallow, Substation Risk: Flood Defense, the Company disagrees that these costs should be

[69] See generally R 792.10427(1) and (3) "The rules of evidence as applied in nonjury civil cases in circuit court shall be followed as far as practicable…" "A party…shall have the right to submit rebuttal evidence."

disallowed and that the documentation is inconsistent as alleged. The scope and timing provided in Exhibit A-23 Schedule M4 clearly indicate the Substation Risk: Flood Defense Project and the Substation Risk: McGraw Project are two different projects. Each project has unique scope and timing. The Substation Risk: Flood Defense involves the installation of back flow prevention, emergency dewatering pumps and sealing conduit at six substations, including McGraw Substation, with construction in 2023 (Exhibit A-23, Sch M4 p.41). The purpose of The Substation Risk: McGraw project is to return the McGraw Substation to permanent service (including acquiring parcels, transferring load and decommissioning equipment with construction in 2024 (Exhibit A-23, Sch M4 p. 31, 33). As such historical costs relative to Substation Risk: Flood Defense should be allowed.

2. 4.8 kV Hardening.

The 4.8kV Hardening program was developed as a cost-effective way of providing improvements in safety and reliability in areas of Detroit that have abandoned City of Detroit Public Lighting Department (DPLD) arc wire. The Hardening program is a near-term program, which was designed to be constructed at a faster pace than the longer-term plan to convert the entire 4.8kV system in the city of Detroit, which is estimated to cost over $4 billion and take more than a decade to complete. Primary components of the program include replacing or reinforcing poles as necessary, replacing wooden cross-arms with fiberglass cross-arms, removing DPLD arc wire (consistent with the Commission's Order in Case No. U-18484) and DPLD distribution wire from DTE Electric-owned equipment, removing service lines to abandoned properties, and trimming trees to support construction activities (Elliott Andahazy, 3T 506-509). The Commission previously agreed with the ALJ, who "agreed with DTE Electric that the 4.8 kV hardening proposal is economically efficient and that a more complete conversion of the system to 13.2 kV would be

expensive and provide limited incremental benefit" (May 2, 2019 Order in Case No. U-20162, pp 31, 33).

In the Company's 2019 electric rate case, U-20561, the Commission recognized the indicated concerns were substantially addressed in Case No. U-20162, but directed the Company to "provide a more detailed explanation of the factors and scoring process the company uses to prioritize the circuits to be hardened" (May 8, 2020 Order in Case No. U-20561, p 110). Most recently, the Commission directed that "DTE Electric, the Staff, and interested stakeholders shall conduct one or more technical conferences in the first quarter of 2023" with a list of objectives related to exploring "the benefits and costs of 4.8kV hardening versus other alternatives such as conversion or tree trimming" (November 18, 2022 Order in Case No. U-20836, pp 92-93). The Company was in the process of scheduling and preparing for a technical conference when this case was filed (Elliott Andahazy, 3T 510). The Technical Conference was subsequently held on March 22, 2023, where it was led by Staff and included significant stakeholder (including intervenor stakeholder) participation.

Customers in the Detroit area whose circuits have already been hardened have benefitted because the program has proven very effective in improving the safety, reliability, and resiliency of circuits. Circuits that were hardened experienced a 26% reduction in wire downs vs an increase of 20% in the control group; a 46% reduction in All-Weather SAIFI vs an increase of 26% in the control group, and a 73% reduction in SAIDI ex-MEDs vs a 5% reduction in the control group (3T 514-515).

As in prior proceedings, the Company was criticized with claims that it should both do more and do less. For example, Staff suggested that arc wire should be removed more quickly, while AG/MNSC witness Stephens proposed that "the costs of this program be disallowed in full and

removed from future capital spending plans" (6T 3397), based on his use of Mr. Alvarez's risk-informed benefit cost formula to claim that "the 4.8kV hardening program is not a remotely cost-effective way to improve reliability," plus various unsupported and speculative assertions about safety (6T 3396).

The PFD states:

> First, this PFD notes Staff's significant safety concerns. . . .
>
> Second, this PFD finds persuasive MNSC, the Attorney General, DAAO and CEO concerns regarding the efficacy of this program, which clearly involves significantly more than arc wire removal as Dr. Wang clearly explained. DTE also appears to be abandoning the program without responding to the critiques. [PFD, p 240.]
>
> * * *
>
> [T]his PFD concludes that the projected bridge period and test year spending for this program should be rejected as MNSC and the Attorney General recommend, with the additional proviso that DTE be allowed to defer its costs of arc wire removal for subsequent review and approval to remove all arc wire as efficiently and expeditiously as possible, providing regular reports to Staff on its plans. [PFD, p 242. See also, p 849]

This proposed full disallowance should be rejected. Past Commission orders support the continued implementation of this program (e.g., November 18, 2022 Order in Case No. U-20836, pp 92, 94, approving cost recovery despite various criticisms, and clarifying the Commission's support for reasonable and prudent cost recovery of the Company's arc wire removal program). Furthermore, contrary to the conclusion in the PFD that DTE Electric did not respond to "critiques," Company witness Elliott Andahazy explained and justified the various challenges and activities associated with the removal of arc wire:

> Tree trimming is necessary to gain access to the wire. Testing and replacing, or reinforcing, poles is necessary to make the site safe for workers and the public. Crossarm replacement and rebalancing is likewise necessary, as only removing the arc wire could potentially leave crossarms dangerously unbalanced, and could create hazards. Unbalanced crossarms would occur because arc wire and the Company's

> overhead lines were originally installed to provide equal force on each side of the crossarm; when the arc wire is removed, the remaining DTE wires exert force on only one side of the crossarm, resulting in the need for the wires to be rebalanced so they are properly supported. (Elliott Andahazy 3T 509)

The PFD's reasoning is contrary to the record, as well as inconsistent. For example, the PFD suggests that the Company should remove arc wire faster in this context, but elsewhere (e.g., PFD, p 234) criticizes the Company for increasing its arc wire removal. Mr. Stephens acknowledged that the program offers safety benefits, while his criticisms of the program are unfounded and speculative.[70] Mr. Stephens' assertion that "the 4.8kV hardening program is not a remotely cost-effective way to improve reliability" (6T 3396) misses the mark because the program was created first and foremost as a *safety* program not a reliability program. The program aligns with the Commission's expectation that the Company remove arc wire, as reflected in the November 18, 2022 Order in Case No. U-20836, p 94. With that said, however, the program also provides

[70] For example, Mr. Stephen's admits that "the program does appear to reduce wire down events, though the percentage of wire down events consisting of non-electrified DPLD wire, which has likely not been maintained for decades, is probably high." (6T 3396). He then wrongfully asserts that "the Company indicates that it does not track safety incidents on its 4.8kV system. Thus, I assume that the vast majority of wire down events are associated with the non-electrified DPLD wire." *Id*.

The Company disagrees with Mr. Stephens on this point for three primary reasons, First, Mr. Stephens assertion is dangerous as it gives the false impression that downed arc wire is safe. It is incorrect to assume that all DPLD wire downs are non-electrified. Instead, they might become energized either directly or through contact with energized wires. Indeed, the Commission also requested that the Company remove arc wire because downed DPLD wires present a safety hazard (Elliott Andahazy, 3T 588).
Second, Mr. Stephen's assertion that "the Company indicates it does not track safety incidents on its 4.8kV system" is in reference to a discovery response asking the Company to, "[p]rovide the count of OSHA-reportable safety incidents that occurred on the 4.8KV system from 2018-2022." As discussed above, the Company disagrees that OSHA recordable incidents are appropriate to measure the success of capital investments associated with safety because OSHA recordable incidents are a lagging metric used for employee injuries that meet a certain threshold. OSHA incidents do not capture hazards associated with the public (Elliott Andahazy, 3T 567-68, 589).

Third, based on the two assertions discussed above, Mr. Stephens "assume[d] that the vast majority of wire down events are associated with the non-electrified DPLD wire." This assumption neglects, as indicated above, that any wire can come down, be energized, not create an OSHA recordable incident, and yet it still should be considered a safety hazard until it is fixed. By assuming that "the vast majority" of wire downs are associated with non-electrified DPLD wire, it assumes the 4.8kV system and associated wire downs are only in the city of Detroit where the arc wire is located. In reality, the Company's 4.8kV system extends from Ann Arbor to the west and up into the thumb. (Elliott Andahazy, 3T 589-90).

significant reliability benefits as a secondary benefit to safety (Elliott Andahazy, 3T 506-507, 512-14, 590-91).

The PFD's second finding (quoted above) is particularly inconsistent with the record as well as reasonable and prudent utility practice. It is true that the hardening program involves more than arc wire removal, but it is not practical to simply remove arc wire without some of the other steps of hardening. For example, Mr. Stephens asserted that "[i]t appears that a more cost-effective way to reduce wire down events would be to remove the DPLD wire, and not take on the capital cost of hardening" (6T 3396). In addition to the discussion above regarding the flawed bases for that assertion, Mr. Stephens also neglected to consider removing the arc wire without doing additional work on the pole tops would leave the cross arms unbalanced, which could not only create safety issues but increase wire downs with corresponding outage increases and reactive costs (Elliott Andahazy, 3T 509, 591).[71]

Similarly, the PFD's reasoning is inconsistent with itself (e.g., if the PFD is concerned about safety, then it should not suggest doing something that would be unsafe). The PFD's suggestion that "DTE also appears to be abandoning the program without responding to the critiques" (PFD, p 240) is similarly unfounded and inapt. Instead, the Company has repeatedly faced criticisms in past cases as indicated above (and the Commission is undoubtedly well aware), and the Company is "responding to the critiques" through facilitation of a technical conference and continuing to explore options to remove arc-wire efficiently and timely, while maintaining safe operation of the system.

[71] Mr. Stephens' analysis is also flawed in this context because it does not capture all benefits of the 4.8kV Hardening program. The analysis focuses only on reliability improvements, but the program also provides additional benefits including safety improvements (measured by wire down reductions), avoided O&M and reactive capital costs (e.g., reduced reactive costs due to reduced events requiring the dispatch of a line crew), and regulatory compliance (Elliott Andahazy, 3T 512-14, 587-88; Exhibit A-23, Schedule M7, page 243; Exhibit A-23, Schedule M4, p 44).

Therefore, the Commission should reject the PFD's proposed disallowance for lacking a sound evidentiary basis, as well as for being demonstrably unsafe, unreasonable, and imprudent based on the record in this case and as further established in past cases recognizing the safety and other benefits of the 4.8kV Hardening program.

3. Pole and Pole Top Maintenance and Modernization (PTMM).

This program proactively identifies and replaces damaged or defective poles and pole top equipment before unexpected failures occur (Elliott Andahazy, 3T 517). In Case No. U-20836, the Commission indicated support for the program, but ordered a partial disallowance with an opportunity for later recovery, stating:

> The Commission notes that pole and poletop maintenance and modernization is an important activity for improving reliability and is supportive of the program and is also supportive of effective and well-reasoned proactive repair and replacement of equipment prior to failure. However, the Commission agrees with the ALJ that DTE Electric did not clearly explain its basis for the significantly increased cost projections or the company's standard for remediation versus replacement. . . . Therefore, the Commission adopts the Staff's proposed 15% reduction to the capital expenditures for this program as discussed above. The Commission also finds that the incremental disallowance proposed by MNSC should be approved. The Commission notes that the company has the ability to spend above the level of capital approved in this case and may recover the amount in a future case after the spend is proven to be reasonable and prudent. [November 18, 2022 Order in Case No. U-20836, pp 99-100.]

Accordingly, Ms. Elliott Andahazy explained that in 2019 the Company added enhanced specifications, including changes to the poles and pole-top hardware used, and to testing and inspection processes, based on benchmarking and other learnings (Elliott Andahazy, 3T 517-20; Exhibit A-23, Schedules M8 (Wood Pole Maintenance Specification) and M9 (Pole Top Maintenance Specification) provided as Exhibits in this case in response to the Commission's feedback in Case No. U-20836 above). The more robust specifications have resulted in increased

PTMM investments, since the amount of work required per circuit mile increased (Elliott Andahazy, 3T 521-23).

The Company inspects poles on a 10- to 12-year cycle, and historically has achieved this target by using various inspection processes. In 2022, the Company discontinued using Joint Use inspections[72] for this purpose, and began exclusively using the more comprehensive PTMM, 4.8kV Hardening, and 4.8kV Conversion programs for pole and pole top hardware inspections. This has resulted in a greater number of inspections performed by the PTMM program, at the enhanced specifications discussed above (Elliott Andahazy, 3T 524-25).

The Commission previously directed:

> [A]s part of the company's next rate case, DTE Electric shall: (1) provide a thorough breakdown of the total pole inspection and test costs which are applied across all capital programs and subprograms, (2) support why these costs are appropriately classified as capital costs instead of O&M with reference or references to accounting principles and guidance, and (3) amend the classification of these expenditures, where appropriate, based upon the analysis. [November 18, 2022 Order in Case No. U-20836, p 471].

The Company has supplied the cost breakdown, and the issue has otherwise become moot. Company witnesses Elliott Andahazy and Uzenski explained that pole inspection and testing costs are reflected on Exhibit A-12, Schedule B5.4, page 8, line 12 (4.8 kV Hardening, which is discussed in the section above) and line 13 (PTMM, which is discussed in this section). Exhibit A-12, Schedule B5.4.8 provides a breakdown of those costs at lines 1 - 5 (4.8kV Hardening) and 6 – 11 (PTMM). Inspection and testing costs are shown at line 2 (4.8kV Hardening) and 7 (PTMM). Inspections for the 4.8kV Hardening program were concluded in 2022. The Company changed its

[72] Joint Use inspections are less comprehensive visual inspections that do not directly address pole top hardware, and are mainly intended to ensure that there is proper clearance between utility and telecommunication lines (Elliot Andahazy, 3T 525).

accounting policy, effective January 1, 2023, to shift inspection costs associated with the PTMM program to O&M (Elliott Andahazy, 3T 530-31; Uzenski, 5T 1506-1507).

The enhanced pole specifications and inspection process align with industry best practices and will reduce the risk of pole and pole top equipment failures, improve customer reliability, and reduce reactive costs during trouble or storm events. Customers benefit because overhead-equipment related outages account for almost 25% of all events. As a result of executing the improvements to the PTMM program, the Company expects a further reduction in equipment-related outage events, which will drive reliability improvements, reduce reactive and storm expenditures, and improve safety by reducing pole and pole top equipment failures and downed wires (Elliott Andahazy, 3T 520, 528).

MNSC witness Ozar disagreed with the Company's reasons for increasing investments, and arbitrarily proposed that "the projected PTMM capital expenditure be set at a level of $63.445 million, which is the same level projected in the 2023 bridge period" (6T 3560). The PFD agreed, stating:

> This PFD finds that DTE has failed to support its projected level of expenditures for this program. Indeed, it has not explained why it has ignored the spending level set by the Commission in Case No. U-20836. Mr. Ozar's testimony is persuasive that DTE has not established that it is applying reasonable and prudent standards in determining what poles to remediate. As MNSC argues, in Case No. U-20836, the Commission found that "DTE Electric did not clearly explain the basis for the significantly increased cost projections or the company's standard for remediation versus replacement." Under the circumstances, MNSC's recommendations provide substantial leeway for DTE to implement a reasonable pole and pole top inspection and repair and replacement program. [PFD, pp 251-52. Footnote omitted.]

The Company maintains that its reasons for increasing investments are valid and fully support its proposed level of funding. These reasons include increased reliability, reduction of reactive and storm expenditures and improved safety though the reduction of wire downs (3T 528). Therefore, as indicated above and further discussed below, the PFD/MNSC's criticisms of the

PTMM program and proposed investment cap should be rejected, and the Pole/PTMM program should be fully funded.

Mr. Ozar indicated that the enhanced standards were adopted years ago, so they are not "new" and therefore are not contributing to recent investment increases (e.g., 6T 3547). This is inaccurate for two primary reasons: (1) Although the enhanced standards were formally adopted in the second half of 2019, their full implementation required extensive retraining of the Company's workforce, which did not begin until 2020; and (2) The COVID-19 pandemic significantly hampered the Company's ability to perform inspections in 2020. Therefore, the full effects of the new standards and inspection practices did not begin to generate significant additional work volume until 2021 and were not fully realized until 2022. The enhanced standards have identified more poles and pole top equipment locations to be replaced per circuit mile inspected, with corresponding increases in the overall scope of work and associated investment levels. Mr. Ozar's further suggestion that the Company's inspection cycle is only "marginally shorter" than past years (6T 3547) also neglects that the Company relied on Joint Use inspections prior to 2022 to reach its target of a 10-12 year inspection cycle. The expenditures for these Joint Use inspections were not captured under the PTMM program, and these Joint Use inspections identified significantly fewer defects per circuit mile, since they were focused on maintaining proper clearance between utility and telecommunication lines rather than the condition of pole top equipment (Elliott Andahazy, 3T 522-25, 594-96).

Mr. Ozar suggested that the enhanced standards would decrease failure rates through earlier detection of pole decay and remediation before failure, and that increased PTMM is not being driven by the backlog of distribution assets that failed recent inspections and were not previously remediated (e.g., 6T 3547-49). These suggestions conflate two different categories of work that are

separate regarding how they are managed and where expenditures are captured: (1) in-service failures of pole and pole top equipment, which are captured in the Non-Storm and Storm categories and do not appear in the Pole/PTMM program; and (2) poles and pole top equipment that fail PTMM visual and physical inspections, which are remedied under the PTMM program. The PTMM program includes expenditures for inspections and for remediating poles and pole top equipment that fail those inspections. The existence of a PTMM backlog means that not all of the work identified in prior years was performed in those years (because the Company is identifying more defect locations per circuit mile than it identified historically) and supports the Company's argument that the PTMM program needs increased investment to accomplish its scope of work under the enhanced standards and inspection practices (Elliott Andahazy, 3T 522-23, 593-94, 598-600).

Mr. Ozar further asserted that "the persistent backlogs, exceptionally large variance in inspections from year to year, and unreasonable level of modernization, demonstrate substantial mismanagement of the program." (6T 3547-48). The Company disagrees. Addressing these criticisms in order, the Company incorporates the discussion above regarding backlogs. Inspection totals were 74,000 to 114,000 from 2017-2022, which is not an "exceptionally large variance in inspections from year to year," particularly since the only year with a significant variance was 2020 and was due to the COVID-19 pandemic. Also, as indicated above, the Company made changes to the PTMM program specifications in the second half of 2019, which were fully implemented after some delay due to COVID-19. Mr. Ozar's assertion of an "unreasonable level of modernization" is similarly unfounded. The PTMM program only replaces poles and pole top equipment that fail inspections or are known to have manufacturing defects that lead to elevated failure rates. The modernization aspect of PTMM means that when wooden poles, wooden crossarms, porcelain

cutouts, and porcelain insulators fail inspections and are replaced, they are done so to current, more resilient standards, which include stronger poles, fiberglass crossarms, and polymer cutouts and insulators. Mr. Ozar also "acknowledge[d] that for those poles that are inspected and deemed in need of replacement, that the stronger and taller poles meeting the new engineering standards may cost more than poles meeting the previous standards" (6T 3549). Therefore, there is no sound basis for Mr. Ozar's criticisms (Elliott Andahazy, 3T 600-601).

Mr. Ozar further suggested "that DTE move to a risk-based pole and pole top maintenance program" (6T 3557). The Company disagrees because the current PTMM program already accounts for risk, as only assets that fail inspection and are deemed to be at high risk of failure are replaced. The Company also benchmarked other utilities in the Midwest and Northeast and determined that it is common practice for utilities to manage their PTMM programs on a 5 to 10-year cycle. A 10-year inspection cycle also comports with Staff's November 20, 2009 Utility Pole Inspection Program Investigation Staff Report. (Elliott Andahazy, 3T 603-604).

Mr. Ozar further suggested that the Company report annual metrics to the Commission with respect to its pole and pole top inspection and testing, similar to the Company's annual tree trimming reporting (6T 3559-60). The PFD found that the "reporting recommended by Mr. Ozar will likewise provide accountability for the program administration" (PFD, p 252). While the Company does not oppose this suggested reporting per se, it is redundant as much of this information is already submitted to Staff through the Company's Annual Pole Inspection Report and has been provided in this case (Exhibit A-12, B.5.4.8 PTMM/4.8kV Hardening Details). As such, Mr. Ozar's suggested reporting does not support the PFD's implication of lack of accountability or support disallowance.

4. Cable Replacement, and Underground Residential Distribution (URD) Replacement.

The Cable Replacement program prioritizes and proactively replaces at-risk system cable[73], consisting of underground trunks and tie lines that connect substations, prior to in-service failures based on multiple factors including cable type, vintage, failure history, system impacts, and cable loading. The Company replaced 4.9 miles of system cable in 2022, and is targeting approximately 17 miles in 2023, and 19 miles in 2024. This ramp-up of cable replacement efforts will benefit customers through reduced risk of lengthy outages, improved reliability, and lower reactive costs (Elliott Andahazy, 3T 535-37, 580-81).

The URD program prioritizes and replaces URD cable[74], used for underground residential applications, based on multiple factors including vintage, number of failures, and number of customers affected by those failures. There are approximately 11,000 miles of URD cable on the system, with approximately 2,100 miles (19%) being pre-1985 (non-tree-retardant).[75] The program also replaces live-front transformers with dead-front transformers, as a safety enhancement (Elliott Andahazy, 3T 537-39, 581).[76]

The Company has successfully ramped up its underground replacement program in recent years and is confident that it will be able to execute the URD Replacement program presented in this case (45 miles in 2022; 80 miles in 2023; and 87 miles in 2024). Customers benefit from

[73] System cable is a specific type of cable designed and used for underground distribution and subtransmission on the Company's primary electric system. System cable consists of large diameter cable surrounded by insulation, and it is installed underground in vaults and ducts between manholes.

[74] URD is a specific type of cable designed and used for underground residential use on the Company's secondary electric system. URD consists of small diameter cable surrounded by polyethylene insulation and is either directly buried into the ground or installed inside conduit.

[75] "Treeing" refers to the tree-like pattern of insulation breakdown. The breakdown typically originates at an impurity or defect in the solid insulation and grows gradually over time to resemble the branches of a tree, ultimately leading to a cable failure (Elliott Andahazy, 3T 537-38).

[76] Live-front transformers have no protective coverings over energized equipment, and therefore pose a potential safety risk to crews performing work once the external transformer covering is removed (Elliott Andahazy, 3T 539).

improved reliability because the program will reduce the number and length of customer interruptions due to URD cable failures. Customers also benefit from a reduced risk of multiple failures and long-duration outages (Elliott Andahazy, 3T 540-42).

AG/MNSC witness Stephens recommended disallowance of capital expenditures for both programs, once again asserting "unless and until the Company produces a risk-informed cost-benefit analysis that indicates its cable replacement programs are cost effective, I recommend recovery of cable replacement costs be disallowed in full and removed from future capital spending plans" (6T 3394). The PFD agreed, stating:

> This PFD finds that DTE has failed to support the reasonableness and prudence of its expenditures in this category. As with the rest of the analysis that may underlie its GPM, it has failed to provide that analysis for review in this case. DTE did not establish that it is reasonable and prudent for it [to] replace all cable on a circuit based on fault, age, and/or type of cable on a part of a circuit, and did not respond to Mr. Stephens' straightforward testimony that many types of cable are found on an entire circuit, or to his analysis showing increased outages following the 2020 cable replacement. Because DTE's analyses have not been provided, and because the prioritizations in its model have not been able to be validated, this PFD finds the projected bridge and test year costs should be excluded from rate base. [PFD, pp 258-59.]

The Company maintains that it supported the reasonableness and prudence of its expenditures in this category, which should be fully approved. Much of the PFD's contrary reasoning echoes the PFD's criticisms of the GPM. The Company disagrees because, as indicated above, (1) the Company already uses risk-informed decision making as part of the GPM, (2) witnesses Alvarez and Stephens do not offer any evidence to show that their methodology is better (or even that it is "data driven" as it purports to be rather than subjective), and (3) considerable evidence indicates that it would be worse because it fails to consider all relevant criteria, such as safety improvements (Elliott Andahazy, 3T 581-82).

The Company also responded to Mr. Stephens and further supported its expenditures in this category with specific evidence that the PFD disregarded. The record reflects that the Company has criteria for replacing both system cable and URD, which were selected by the Company's subject matter experts (SMEs) based on their experience with the Company's system as well as industry experience (Elliott Andahazy, 3T 531-42, 584; Exhibit A-23, Schedule M7, pages 203-204 for system cable (insulation type, cable loading, and past failures), and page 206 for URDs (manufacturing year [pre-1985 due to treeing issue] and number of outages)). Mr. Stephens did not consider these criteria. Instead, he asserted, quoting a discovery response, that the Company uses "the completely premature approach . . . [of] prioritizing the replacement of all underground cable on a circuit based on historical failures on that circuit, 'because this cable was installed around the same time with the same cable type and has experienced the same or similar soil and loading conditions.'" (Stephens, 6T 3392).

The quote was part of a discovery response (Exhibit A-42, Schedule GG3) regarding how the Company selects URD cable replacement. Mr. Stephens neglected (1) the significance of "treeing" (insulation breakdown on pre-1985 URD cable), (2) the significance of "same cable type" in the quote from the discovery response, and (3) non-tree retardant XLPE URD cable is one of the replacement factors for the program. Treeing of cable insulation is a well-known failure in URD cable throughout the industry. If an area is experiencing multiple failures, then in the Company's SMEs' experience that means that the adjacent cable is likely to have the same type of insulation and has increased risk of additional failures. System cable has a similar insulation reliability concern relating to "treeing" for pre-1990 cable with XLPE insulation, and there are four cable types with known limitations or defects that are included in the Company's replacement criteria (Elliott Andahazy, 3T 583-84; Exhibit A-23, Schedule M7).

The Company therefore has clear and rational criteria for replacement based on issues known in the industry and further supported by the SMEs' experience with the Company's system. Mr. Stephens did not dispute the criteria, but instead based his proposed disallowance on a partial quote from a discovery response, which he misconstrued. Mr. Stephens also did not dispute the merits of the programs, but instead proposed a total disallowance based on his application of Mr. Alvarez's proposed risk-informed equation, which has numerous flaws, and is also unnecessary because the Company already performs a risk-informed analysis in the GPM. Therefore, the recommended disallowance should be rejected (Elliott Andahazy, 3T 585).

The PFD "further recommends that the Commission require DTE to separate its expenditures by project so the costs for individual projects can be reviewed and evaluated in subsequent cases, and additionally consider looking further into Mr. Stephens' observation regarding the poor quality of outage data maintained by DTE" (PFD, p 259). Implementation of this recommendation is neither practical nor beneficial in the context of cost management. Cable replacement work involves the replacement of the same assets on every project. Each subproject has unique factors driving cost differences which is a primary reason cable replacement (and other similar programs such as tree trim) have historically been tracked by miles. Tracking the individual cost of every subproject would not only require costly and impractical changes to accounting, project management and tracking processes, it would result in an extensive expansion of data incorporated into rate case exhibits which are unlikely to lend themselves to meaningful review.

5. Breaker Replacement.

This program replaces obsolete circuit breakers,[77] and also replaces relays and controls to enable supervisory control and data acquisition (SCADA) utilization on equipment, to give the Electric System Operations Center (ESOC) greater visibility into system performance. Customer benefits include enhanced safety, reduction of substation outage risk caused by breaker failures, improved reliability, reduction in reactive expenditures due to breaker failures, added ability to use SCADA controls, and the reduction of outage duration provided by SCADA capability. Breakers are prioritized for replacement based on criteria that maximize these benefits. The Company plans to replace 35 breakers in 2023, and 36 breakers in 2024, consistent with past years (Elliott Andahazy, 3T 542-44).

AG/MNSC witness Stephens did not propose a specific disallowance for this program, but it was unclear what he proposed. He proposed disallowances of $47,788,000 in the bridge period, and $13,412,000 for the projected test year (6T 3401), which match the Company's requests for the Substation Risk projects, but he cited Exhibit A-33, Schedule X1, which relates to the Breaker Replacement program. MNSC's Initial Brief, pp 72-73, argued for a disallowance in this area by asserting that "Mr. Stephens considered the cable breaker replacement program as a substation equipment replacement program." (MNSC Initial Brief, p 72, n 313). The assertion is unsupported by citation and failed to suggest any reason why Mr. Stephens would consider it as such. The Company maintains that to the extent that Mr. Stephens suggests a further disallowance for the Breaker Replacement program, it should be rejected as unsupported. The Company also incorporates its prior discussion demonstrating that Mr. Stephens' application of Mr. Alvarez's

[77] A circuit breaker is an electrical switch designed to isolate faults that occur on substation equipment, buses, or circuit positions, and thereby minimize equipment damage (Elliott Andahazy, 3T 542).

suggested risk-informed benefit cost analysis has numerous flaws and is entitled to no weight, so any recommendation based on it should be rejected (Elliott Andahazy, 3T 579-80).

With respect to the Breaker Replacement Program, the PFD states:

> Consistent with the foregoing discussions, this PFD finds that DTE has not supported the reasonableness of its program, and concludes that the projected bridge and test year costs should be disallowed. DTE generally, and Ms. Andahazy in particular, could have presented DTE's analysis of the cost justification for this program, but chose not to. [PFD, pp 260-61.]

The PFD's sweeping disallowance ($13.2 million in 2023 and $15.2 million in 2024) fails to address the considerable evidence put forth by the Company relative to the reasonableness of the program and its related costs (See 3T 542-544, Exhibit A-23 Sch M7 Sec. 8.3). Candidates for breaker replacement include but are not limited to those that have no available parts for repair, have known performance issues and have insulation oil for fault interruption which is flammable. (3T 542-544, Exhibit A-23 Sch M7, Sec. 8.3). The Company also provided a breakdown of precisely how many breakers were planned to be replaced in 2023 and 2024 (3T 544). As such, the PFD's recommended disallowance is inappropriate.

b. Infrastructure Redesign and Modernization.

Infrastructure Redesign and Modernization projects and programs fundamentally upgrade the electrical system and fall into three primary areas: (1) Subtransmission Redesign and Rebuild; (2) Conversion to higher voltage (City of Detroit Infrastructure (CODI) and Conversions); and (3) System Loading (Deol, 2T 195-96); Exhibit A-12, Schedule B5.4, pp 9-11 (listing projects); Exhibit A-23, Schedule M5). The Company projects capital expense associated with these projects of $475.4 million in the 23-month bridge period ending November 30, 2023, and $526.4 million in the projected test year (Exhibit A-12, Schedule B5.4, p 11, line 111, columns (b), (f), and (g)).

The PFD indicates support for the recommendations of AG/MNSC witness Stephens. Therefore, as a preliminary matter and in addition to the discussions above, the Company outlines the following reasons this support is inappropriate.

Mr. Stephens asserted that "DTE appears to be basing its need to convert all its circuits to 13.2kV within 15 years on EV growth," referencing the Company's 2021 Distribution Grid Plan (DGP, Exhibit A-23, Schedule M7) and the Company's directionally-plausible forecast for EV growth (6T 3373). There are many concerns with Mr. Stephens' speculative and unsupported assertion. First, the Company does not assert any need to convert all of its circuits in 15 years. Exhibit A-23, Schedule M7, page 319 reflects that the conversion is likely to take decades, but the Company has an aspirational goal to convert in 15 years. In any event, this case involves shorter-term investment projects that support current capacity and reliability needs, not future electrification needs as a driver, as further discussed below (Deol, 2T 241).

Mr. Stephens's reliance on the EV forecast and his assertion that the Company based plans for conversions on that forecast was misplaced. The purpose of the directionally-plausible forecast first introduced in the 2021 DGP was to understand how increased load from EV adoption might stress the distribution system as part of the DGP's Electrification scenario planning analysis. The forecast was not intended to predict a specific impact on peak load or directly support specific investments, as further reflected in the Company's response to discovery (Deol, 2T 237-38, 243; Exhibit A-41, Schedule FF1) ("This directionally plausible forecast served the purpose to highlight needs of a particular plausible future and was not used to determine specific capital investments.").

Mr. Stephens further asserted that "[i]t appears to me that the Company's Area Load Analysis, completed in 2020, artificially de-rated the capabilities of circuits and substations" (6T 3375) and "[i]t wasn't until I reviewed the EV loading workpapers late in discovery that I realized

the capabilities the Company was assigning to its substations were subjectively determined rather than based on the manufacturers' nameplate capacity ratings" (6T 3381). The PFD similarly references "Mr. Deol's workpapers" and "EV workpapers" (PFD, pp 269-70). There is no such thing. The intended reference is to the directionally-plausible forecast discussed above, which again was not used to support any projects or programs in this instant case.

More importantly, in addition to Mr. Stephens above-described inaccuracy, he is simply wrong on the merits. The Company's substation ratings are *not* subjectively determined or artificially de-rated. The Company bases its substation ratings on defined equipment ratings. Mr. Stephens definition of substation capacity (6T 3380) is similar to the Company's definition, as both use equipment rating to determine capacity. The key difference is that the Company appropriately includes single contingency consideration in its planning. A single contingency condition is one in which a piece of equipment fails, and an adjacent piece of equipment is required to pick up the load normally handled by the failed equipment in order to maintain uninterrupted power for customers (Deol, 2T 240). To not include single continency in grid planning would mean that planning assumes all equipment is always fully available, never unavailable due to maintenance or a failure. This would be inappropriate, and inconsistent with industry practice.

Although the PFD indicates "confusion" on this point (PFD, p 283, n 834), the concept is straight forward: in order to provide uninterrupted power to its customers, the Company must plan for equipment failure and maintenance. The record further reflects that the Company's practice is prudent and otherwise appropriate because if the Company did not rate substations based on a single contingency, then the Company would experience additional failures as adjacent equipment would quickly become overloaded, causing cascading failures resulting in customer outages (Deol, 2T

229, 239-40, 243, 366, Exhibit A-47, page 1). Mr. Stephens acknowledges that equipment cannot operate under overloaded conditions for long (Stephens 6T 3375).

Mr. Stephens similarly misinterpreted the Company's EV forecast from its IRP case, U-20194 (6T 3374-75). Neither the IRP nor the DGP EV forecasts were directly used in the development of any distribution projects/programs in this case or the IRM period. The projects in this case are supported by specific evidence presented in testimony and exhibits. Therefore, the Commission should reject Mr. Stephens' interpretation of the EV workpapers (as he and the PFD refers to them) and any recommendations based on them (Deol, 2T 242-44).

Mr. Stephens presented a table reflecting his arbitrarily proposed 50% disallowances of capital for Circuit Conversions, CODI, System Loading, and Subtransmission Redesign and Rebuild, and asserted that "even with my recommended disallowances and reductions in planned spending for these programs (50%), the remaining capital spending budgets still represent significant increases over historical (2021) capacity expansion spending levels. As a result, even the reduced level of capital spending I recommend will be much more than adequate until a new and improved distribution planning process can be installed" (6T 3383-85).

The Company disagrees because it provided detailed analysis for each of its capital projects, including how they are developed, vetted, and ranked (See, e.g., Kryscynski, 3T 385-95, 426-27; Miller, 5T 2840-44; Exhibit A-23, Schedules M3-M6). In contrast, Mr. Stephens did not offer any support for why a multi-program 50% disallowance would be correct, or how a 50% reduction allegedly "will be much more than adequate", failing to even define what he meant by "adequate". Mr. Stephens did not assess the safety, reliability, or other impacts that a 50% investment reduction would have on any project, nor did he directly dispute the purpose, necessity, reasonableness or

prudency of the projects, or the Company's ability to execute them.[78] Therefore, Mr. Stephens' arbitrary across-the-board 50% disallowance merits no weight and should be rejected (Deol, 2T 245-47).[79]

1. Subtransmission Redesign & Rebuild.

The Subtransmission Redesign & Rebuild program focuses on installing new station equipment and rebuilding both the overhead and underground portions of the Company's subtransmission system.[80] The program is needed to ensure system redundancy, increase capacity for loads from existing and new customers, support DER interconnections, and improve reliability due to aging equipment. Benefits include safety improvements, improved reliability and operability, and increased capacity (Deol, 2T 216-24, 248-50; Exhibit A-23, Schedule M7 DGP, pp 294-95).

AG/MNSC witness Stephens in this investment area also proposed a 50% disallowance, essentially reasoning that capital investment in subtransmission projects could be slowed down dramatically at low risk, based on his misuse of the EV loading workpapers (as he and the PFD inaccurately call the directionally-plausible forecast) and misperceptions that the Company subjectively determined, and de-rated, its substations (6T 3379-84) (which are incorrect as discussed above). The PFD ultimately "does not find that a disallowance is necessary" (PFD, p 275) in a wide-ranging discussion:

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[78] MNSC also acknowledged that Mr. Stephens' testimony broadly concerns the spending rate and not opposition to anything in particular, stating for example that "Mr. Stephens did not oppose these programs generally. Rather, he acknowledged that all infrastructure must be replaced over time, and capacity must be upgraded over time as load grows on a circuit-by-circuit, substation-by-substation basis." (MNSC Initial Brief, p 74. Footnotes omitted).

[79] Mr. Stephens' reference to a "new and improved distribution planning process" referred to the risk-informed benefit-cost analysis suggested by AG/MNSC witness Alvarez. The Company incorporates its prior discussion explaining why the suggested analysis is unnecessary and otherwise lacks merit, particularly as applied by Mr. Stephens.

[80] DTE Electric's Subtransmission system is operated at mid-level voltages of 24 kV, 40 kV, or 120 kV, and is used to step down transmission voltage to serve distribution and industrial substations.

> Before addressing the disputes between the parties, this PFD notes that the majority of these projects are not planned to be completed within the test year. Consistent with this PFD's conclusion above that the myriad projects that DTE acknowledges will remain in CWIP through the test year and do not generate a revenue requirement in this case should be excluded from consideration in this case, this PFD notes that only the projects on lines 42, 44, 46-51, 56-57, 67, 70, and 78 are projects for which DTE seeks rate recovery in this case. The total 11-month bridge and test year spending associated with these projects are approximately $24.6 million and $7.3 million respectively.
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> After reviewing the evidence presented, this PFD finds that DTE has failed to support the reasonableness and prudence of the program, the individual projects, or the pace of spending on this program. . . . Since MEC does not object to spending at the level of costs DTE is actually seeking to include in this rate case, this PFD does not find that a disallowance is necessary, but notes that should DTE present these projects for approval in its next rate case, or through an IRM, it needs to provide the details underlying its analyses, of the circuit upgrades, of the prioritization of circuits for upgrade, and an explanation for the pace with which DTE proposes to make these upgrades, along with an analysis of any alternatives considered, such as prioritizing interrupting devices as endorsed by ITC. [PFD, pp 275.]

As previously explained, Company projects not in service in the projected test period are included in CWIP but have no net revenue requirement because of the AFUDC offset. While agreeing with the PFD's conclusion rejecting the arbitrary 50% disallowance, the Company disagrees with the PFD's evidentiary discussion. The Company incorporates the discussion regarding preliminary matters above in which Company witness Deol discussed the nature of the subtransmission system and why the program is necessary, including the need to address planning criteria violations, and reliability and safety benefits (2T 248-51).

The Company further notes that the PFD was persuaded that "Mr. Stephens expert opinion is credible that DTE's planning criteria require additional justification" in the context of a discussion that misconstrues the evidence and the Company's position (PFD, p 275). Mr. Stephens asserted that "in discovery, the Company could not provide historical safety and reliability data on

the subtransmission system, and it was clear the Company is not even tracking the baseline data required to measure safety or reliability improvements on the subtransmission system," citing "DTE's responses to MNSCDE-7.37(b) (safety)" (6T 3382). The Company properly assumed (and still does) that Mr. Stephens meant to reference MNSCDE-7.37(a) (Exhibit A-41, Schedule FF7), which asked for, "[T]he count of OSHA-reportable safety incidents that occurred with respect to the subtransmission system from 2018-2022." As discussed above, the Company disagrees that OSHA recordable incidents are appropriate to measure the success of capital investments associated with safety because OSHA recordable incidents are a metric used for employee injuries that meet a certain threshold. OSHA incidents do not capture hazards associated with the public (Deol, 2T 252, 256; Elliott Andahazy, 3T 567-68, 589).

As in the discussion above regarding conversions, the Company again emphasizes that its substation ratings are *not* subjectively determined or artificially de-rated as Mr. Stephens suggested. The Company bases its substation ratings on defined equipment ratings. Mr. Stephens' definition of substation capacity (6T 3380) is similar to the Company's definition, since they both use equipment rating to determine capacity. The key difference, as indicated above, is that the Company includes single contingency consideration[81] in its planning. This is prudent and otherwise appropriate because if the Company did not rate substations on a single contingency, then the Company would experience additional failures as adjacent equipment would quickly become overloaded, causing cascading failures resulting in a significant number of customer outages (Deol, 2T 229, 239-40, 243, 366, Exhibit A-47, page 1).

[81] A single contingency condition is one in which a piece of equipment fails, and an adjacent piece of equipment is required to pick up the load normally handled by the failed equipment in order to maintain uninterrupted power for customers (Deol, 2T 240).

The Company also maintains that it is reasonable and prudent to use planning criteria, as shown in Table 6 2T 218, violations to define the risks and potential of equipment failures on the subtransmission system to improve system reliability. Mr. Stephens neglected that planning criteria violations are a measure of reliability as noted "[t]he Company determines the reliability on the subtransmission system by analyzing criteria violations, which directly impacts the availability of the redundancy of the system." (2T 253). [82] Mitigating these planning criteria violations through station and subtransmission investment projects is required to continue to serve customers' growing loads during normal system configurations, and to provide the necessary system redundancy to avoid the risk of large customer outages when contingency scenarios occur. The Company also provided a list of circuits in discovery that shows over one-third of the system violates planning criteria, and what planning criteria are violated. Mr. Stephens did not dispute the merits of using planning criteria violations as a measure of reliability. Instead, he misused the EV "loading workpapers" in an attempt to disprove the validity of the violations themselves, incorrectly asserting that the Company subjectively rates substations (6T 3382). As discussed above, the Company's substation capacity ratings are not subjective, but instead are based on equipment ratings, and the Company must consider contingency when planning. Mr. Stephens also did not address the specific purpose, necessity, reasonableness, prudence, or investment for any specific project, or the Company's ability to execute the associated work. Therefore, contrary to the PFD's suggestion, Mr. Stephens' opinion is not credible and should be rejected. (Deol, 2T 253-55).

[82] Planning criteria violations are areas of the system that are not in specification. They have thermal overloads or low voltage during normal or contingency conditions. Thermal overloads can lead to the reduced life of electrical equipment and potentially catastrophic failure. As Company witness Deol explains, low voltage could damage customer equipment and ultimately lead to an outage for parts of or entire substations (2T 253).

2. Strategic Undergrounding (SUG) Program.

The Company's strategic undergrounding pilots seek to understand the viability of undergrounding in different technical scenarios to address grid resiliency challenges. In Case No. U-20836, Staff proposed disallowances[83] reasoning that "capital expenditures for new undergrounding pilots should not be put into rates until the Appoline DC 1346 pilot is completed, and the results known and analyzed" (Case No. U-20836, 8T 5430, dk#754). The Commission agreed that this was reasonable and prudent "until the Appoline pilot is complete and a full report is available, and until a more robust analysis of the benefit/cost of strategic undergrounding is available" (November 18, 2022 Order in Case No. U-20836, pp 111-12).

The Appoline pilot, which has produced important learnings on key challenges with replacing rear-lot overhead infrastructure with rear-lot underground infrastructure, has achieved its primary objective. The Company therefore considers it essentially complete, with all customers now connected. The Company's initial report, as directed by the Commission in Case No. U-20836, was filed as Exhibit A-23, Schedule M10 (Deol, 2T 224-25).

The Company further proposes another Detroit based pilot, which would differ from the Appoline pilot by relocating rear-lot overhead assets to front-lot URD. The Company has leveraged lessons learned from the Appoline pilot, and when the additional pilot is complete, the Company will have a larger data set to perform a benefit-cost analysis for undergrounding projects (Deol, 2T 225-27).

Staff recommended "a full disallowance of the $1,925,000 projected for the 11 months ending 11/30/2023 and $1,917,000 projected for the test year" (Evans, 7T 4415), reasoning that the

[83] These disallowances included $15,100,000 of $17,248,000 for the ten months ending October 31, 2022 and the entire $36,783,000 for the test year. Case No. U-20836, 8T 5430, dk #754.

Company did not comply with the U-20836 Order because "neither Mr. Deol's testimony nor any exhibits provide a benefit/cost analysis of the proposed pilot, so the Company cannot and does not compare it to the benefit/cost analysis of other solutions, such as grid hardening, grid conversion, or tree trimming" (Evans, 7T 4414). AG witness Coppola similarly proposed a disallowance for the pilot, asserting that "the Company has not made a compelling and convincing case that another strategic undergrounding pilot is needed at this time to prepare a cost/benefit analysis of comparable solutions" (Coppola, 6T 3688).

The PFD "concludes that DTE has not established that it is reasonable and prudent to pursue this pilot project. As Mr. Evans testified, DTE has not provided a benefit cost analysis in support of the project, and has not complied with the Commission's instructions in Case No. U-20836" (PFD, pp 266-67).

The Company maintains that the pilot should be approved. Mr. Deol explained that the Company needed a full year of reliability data from 2022 to conduct such an analysis, which was not available when this case was filed (Exhibit A-23, Schedule M6, p 6). Once the data became available, the Company performed an analysis (2T 280-282), but the results were not conclusive, due to the small sample size. The results are not a sufficient basis for any conclusions and indicate that a larger sample size and more time is required to determine the effectiveness of strategic undergrounding. Therefore, the Commission should approve funding for the Company's proposed pilot. This will generate more data, which is the only way to truly determine if strategic undergrounding is a viable option. (Deol, 2T 280-83)

3. City of Detroit Infrastructure (CODI).

This program converts some of the oldest sections of the Company's grid from 4.8kV to 13.2kV through cable replacements, breaker replacements, and other work to address aging

infrastructure. This program is needed to address the significant portions of the electrical infrastructure in the downtown area of the City of Detroit including healthcare facilities, stadiums, and universities, which were placed in service in the early part of the 20th century. Redevelopment in the City of Detroit is stressing this aging infrastructure, and the Company cannot serve new customer load with existing capacity. The Company is focusing on ten CODI projects between 2021 and 2024, as shown on Table 4 at Deol, 2T 211-12 (Deol, 2T 208-13, 268-71; see also Exhibit A-23, Schedule M5 and M7).[84] The PFD states:

> As with certain other line items on Schedule B5.4, almost all of the projects within this category have in-service dates beyond the test year and should be excluded for that reason as explained above. DTE essentially is seeking review of these projects without seeking any revenue requirement associated with them. Consistent with the discussion in subsection a above, this PFD recommends that all projects with in-service dates beyond the projected test year be removed from rate base and not approved.
>
> Nonetheless, recognizing that DTE may seek to recover these costs in a future rate case or through an IRM, this PFD finds that DTE has failed on this record to demonstrate the reasonableness and prudence of its proposed spending for these conversions. [PFD, p 285.]

As previously explained, Company witness projects not in service in the projected test period are included in CWIP but have no net revenue requirement because of the AFUDC offset. The Company also maintains that it properly supported its projects in this category, noting that the PFD presents a narrow discussion regarding one piece of evidence, while disregarding the additional evidence and proceedings leading to this point. More specifically, AG/MNSC witness

[84] Approximately 14% of the Company's customers are in the city of Detroit, but the Company is investing over 30% of its 2022-2024 strategic capital in the city. These projects address aging infrastructure and improve safety and reliability of the distribution system. The CODI and conversion projects in this case will convert the system serving more than 50,000 residential Detroit customers from 4.8kV to 13.2kV (Deol, 2T 213).

Mr. Kryscynski further discussed environmental justice, responded to various indicated concerns and suggestions, and demonstrated how the Company's investments are supporting vulnerable customers and communities (3T 400-420, 428-47).

Stephens asserted, "As with the 4.8kV and 8.2kV [sic, 8.3kV] conversion programs, I recommend spending going forward be cut by 50%, thus spreading the program out over a longer time period, at least until improvements to distribution planning in Michigan such as those recommended by AG-MNSC Witness Alvarez can be developed and put to work" (6T 3378), reasoning: "As with 4.8kV conversions generally, load growth, that is overloading, is a reason to convert, although I do not recommend buying into the Company's claims that loads are growing wholesale, or that capacity ratings are accurately stated. Circuit- and substation-specific load growth forecasts relative to nameplate (not assessed or subjectively determined) substation capacity ratings should be required before any specific projects are authorized by the Commission" (6T 3377). AG/MNSC witness Stephens provides no evidence that he has any (let alone better) experience or understanding of downtown Detroit development as opposed to the Company's electrical system experts. Mr. Stephens testifies that he is "an independent consultant" from Evergreen, Colorado that has not previously testified before the Commission. (6T 3361-3363) Thus, his recommendation to avoid what he characterizes as "buying into the Company's claims that loads are growing wholesale" in downtown Detroit is founded upon uninformed speculation regarding the redevelopment of downtown Detroit that should not have persuaded the ALJ and cannot support a lawful Commission Order in this proceeding.[85]

The Company disagrees with Mr. Stephen's assessment, and again asserts it does not subjectively rate substations. Substations are rated objectively, based on data and industry best

[85] It is well established that an agency decision may not be based on speculation. *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).

practice, and with analysis performed by experienced engineering staff. As discussed earlier, the Company rates substation capacity similar to Mr. Stephens, with the key difference that Company prudently plans for contingency (Deol, 2T 229). As explained supra, there is also no basis for his comment that the Company "claims that loads are growing wholesale." The Company provided a purpose and necessity for each CODI project in Exhibit A-23, Schedule M5. Through discovery, the Company also provided the circuit capacity, historic loading, and forecasting loading for each CODI circuit (Exhibit A-41, Schedule FF4) and additional load-growth information (Exhibit A-41, Schedule FF6). Even Mr. Stephens also acknowledged the undeniable fact and agrees that: "All infrastructure must be replaced over time, and capacity must be upgraded over time as load grows on a circuit-by-circuit, substation-by-substation basis." (6T 3370). As the record demonstrates, now is the time to replace the aging CODI assets many of which were placed in service in the early part of the 20th century. Moreover, Mr. Stephens did not analyze the reasonableness and prudence of any CODI project or its corresponding investment. He simply recommended an across-the-board disallowance based on unfounded and disproven assertions. Because Mr. Stephen's claims lack a sound evidentiary basis, among other reasons, the Commission should reject them. (Deol, 2T 267-71).

Staff proposed disallowances of $56.4 million for the 11 months ending November 30, 2023, and $115.9 million for the projected test year based on a historical calculation, essentially using the 8% increase in CODI spending from 2021 to 2022 as the basis for a 10% annual escalation rate that Staff applied to 2022 costs to get projected 2023 and 2024 costs (Shi, 7T 4697). Staff's Initial Brief, p 29, further explained that Staff "recogniz[es] that the CODI program is indeed necessary to address the downtown Detroit aging distribution system and to provide safe and reliable energy to local customers. Staff supports the Company's execution of the CODI program;

however, Staff has different projected amounts for the bridge and test years compared to DTE's projection." [86]

The Company understands Staff's concerns regarding historic investment levels being lower than projected levels, but the historic numbers do not tell the whole story. The 2021 and 2022 CODI investments were primarily for building and upgrading substations. Now that this work is complete, the investments for 2023 and 2024 will focus on overhead (OH) and underground conversions, which will require more construction work and will be more capital-intensive. The Company has also increased its resources to complete the increased level of work. For example, regarding OH conversion work, the Company has increased its OH workforce from 293 to 659 average daily by month contractors. Additionally, the Company has created a focused Project Management Organization (PMO) to manage and ensure project execution. Staff's concerns have been addressed, and Staff's reliance on historic costs is misplaced in light of the expert Company evidence showing that the investments are necessary, reasonably and prudently planned and supported, and will benefit customers. Therefore, the Company's requested recovery for CODI investments should be fully approved. (Deol,2T 273-75; Miller, 5T 2851-53).

4. 4.8 kV and 8.3kV Conversion Projects.

The 4.8kV conversion project is aimed at upgrading the aged 4.8 kV system to higher grid voltage by building new substations and upgrading circuits to add capacity to serve growing load, address safety issues on the 4.8kV system, and to address deteriorating reliability performance due to aging electrical infrastructure (2T 197-201). Converting all of the 4.8kV substations and circuits

[86] DAAO's Initial Brief, pp 27-30, inaccurately suggested that the CODI program improperly focuses investments on privileged rather than vulnerable communities. This simply is not accurate as the Company is making investments in vulnerable communities under the CODI program, in addition to the 4.8kV hardening program, that will improve reliability in those communities. (Kryscynski 3T 444-445).

will be a significant long-term investment. The near-term (five year) projects reflect investments that address current loading constraints and safety considerations on the system (Deol, 2T 197-201, 258; See also Exhibit A-23, Schedule M7, section 11.3.2). Company witness Deol provided additional details on two representative projects for a deeper understanding of the drivers, scope, and benefits of 4.8kV conversion: (1) I-94 Substation and Circuit Conversion (Promenade) (2T 202-203), and (2) Lapeer – Elba Expansion and Circuit Conversion (Apollo) (2T 204-205).

The 4.8kV ISO Conversion program relates to the Company operating some circuits at 4.8kV that are fed from a 13.2 kV substation, which are known as isolation down areas (ISO down). The program for converting ISO down areas is aimed at upgrading portions of the circuits to a higher voltage, thus adding capacity to serve existing load, improve safety by reducing wire downs, improve jumpering capability to adjacent 13.2kV circuits, and to address deteriorating reliability performance due to aging electrical infrastructure. (Deol, 2T 205-208).

The 8.3kV project concerns the 8.3kV system that serves the city of Pontiac. The Company acquired the system from CMS Energy in the 1980s, and it is the only 8.3kV in the Company's distribution system. As an island surrounded by the 13.2kV system, there is a high risk for stranded load in the event of a substation outage. In addition, the 8.3kV system is aged, and many replacement parts are no longer available. Therefore, the Company has developed a plan to upgrade and convert the Pontiac system to 13.2KV as part of grid modernization, starting with upgrading the system vaults as outlined in previous rate cases and section 8.19 of the DGP (Deol, 2T 214-16, 258; see also Exhibit A-23, Schedule M7, p 341).

The PFD states:

> As with the CODI projects above, this PFD notes that many of them have in-service dates beyond the projected test year and DTE is not seeking any revenue in this rate case attributable to those projects. Consistent with the discussion in subsection a above, this PFD concludes that the projects for which DTE is not seeking rate

> recovery through the revenue requirement in this case should be excluded from rate base. For all the reasons discussed in previous sections, DTE should be cautioned that it will need to provide the analyses underlying its decision-making should it seek to recover these costs in a future case. In addition, it will be providing an analysis as called for by the commission both of its conversion program, and how it will incorporate equity values in its analysis. [PFD, p 290.]

As previously explained, Company witness projects not in service in the projected test period are in CWIP but have no net revenue requirement because of the AFUDC offset. The Company also maintains that it properly supported its projects, incorporating its prior discussions because the PFD just vaguely references other parts of itself to suggest otherwise. For purposes of a full discussion, the Company further notes that AG/MNSC witness Stephens proposed a 50% disallowance for projects in this category, recommending that, "going forward, 4.8kV and 8.2kV [sic, 8.3kV] capital spending be cut by ½, at least until a more complete and rigorous forecast of EV adoption and its impacts on circuit- and substation-specific loads at circuit- and substation-specific peaks can be completed, and until accurate substation-specific capacity ratings can be developed" (6T 3376).

Mr. Stephens' reliance on the EV "loading workpapers" and contention that the Company artificially de-rated the capacities of circuits and substations lack merit. As discussed above, the Company did not rely on the EV "loading workpapers" to justify the conversion projects, and the Company rates substation capacity similar to Mr. Stephens, except the Company prudently plans for contingency. Mr. Stephens also did not criticize the Company's support for the projects, and that support demonstrates that the projects are reasonable and prudent. Mr. Stephens also acknowledged that he does "not oppose these programs generally. All infrastructure must be replaced over time. . . ." (6T 3370). The Company's evidence therefore demonstrates the reasonableness of replacing the 4.8kV and 8.3kV systems at this time due to their age and other

shortcomings including safety and reliability issues, as indicated above and further detailed on the record. (Deol, 2T 24-27, 2T 265-266). [87]

Mr. Stephens also acknowledged that "capacity must be upgraded over time as load grows on a circuit-by-circuit, substation-by-substation basis (6T 3370), and "[l]oad growth, that is, circuit overloading, is indeed a good reason to convert a 4.8kV or 8.2kV [sic, 8.3kV] circuit to 13.2kV; in fact, in my opinion, it is one of the only valid reasons to convert" (6T 3373). Company witness Deol discussed examples of projects where load growth is one of the factors for conversion (2T 29-30). Mr. Deol also provided examples other than loading of valid drivers for the 4.8CC projects (2T 28).[88]

There are three additional concerns with Mr. Stephens' testimony in this area. First, the Company consistently identifies the reduction of wire downs as a key safety benefit. Mr. Stephens did not address safety relating to conversion projects. Mr. Stephens' use of OSHA recordable

[87] MNSC's Initial Brief, p 80, suggested that the Company changed its position and is not credible because "the record is replete with statements by DTE that its massive strategic distribution capital spending generally and its rapid conversion program in particular are needed to support EV growth." MNSC's statement is inaccurate, and unsupported by the various quotes that it provides (discussing EVs among other things such as batteries, solar and DERs). Each conversion project has a specific set of drivers that were presented in the Company's Exhibit A-23, Schedule M5. None of the conversion or CODI projects are being presented with anything other than supported load growth, safety, existing overload, reliability improvements, or other specific needs. EV growth is simply a factor that the Company has properly considered. The purpose of the EV forecast was to understand how increased load from EV adoption might stress the distribution system as part of the DGP's Electrification scenario planning analysis. The forecast was not intended to predict a specific impact on peak load or support investments, as further reflected in the Company's response to discovery (Deol, 2T 237-38, 243; Exhibit A-41, Schedule FF1) (*"This directionally plausible forecast served the purpose to highlight needs of a particular plausible future and was not used to determine specific capital investments."*).

Even MNSC recognizes load growth issues from EVs and otherwise. See, for example, MNSC Initial Brief, p 150, asserting that the "TEP should assess the costs that may be incurred to upgrade the distribution system as EV penetration increases" and pp 133-34, asserting "that *massive* levels of electrification of all fossil fuel heating systems – propane, oil, and gas – are necessary to achieve the levels of greenhouse gas emission reductions necessary to stabilize the climate" (Emphasis in original).

[88] A CC (conversion/consolidation) project could convert an area to higher voltage or consolidate underutilized assets, and in some cases could decommission equipment no longer carrying load (Deol, 2T 258).

incidents as a metric in other categories of investments is also improper as discussed above (Deol, 2T 30-31).

Second, Mr. Stephens did not address the operability of the grid as it relates to conversion projects. Benefits include improved automation and remote operability, as well as improved operability associated with jumpering capabilities (the ability to transfer or shift load to adjacent circuits). (Deol, 2T 264).

Third, Mr. Stephens asserted that "the reliability of DTE's 4.8 and 8.2kV [sic, 8.3 kV] circuits is significantly better than the Company's 13.2kV circuits, as the Table 1 below indicates" (6T 3376). Mr. Stephens's assertion and underlying calculation are incorrect. Mr. Stephens's calculation was based on an average of the 4.8kV/8.3kV and 13.2kV circuit level SAIDI ex-MEDs. SAIDI ex-MEDs are calculated as customer minutes of interruption on a circuit (excluding MEDs) divided by customers on a circuit (See Exhibit A-47, page 4). As each circuit has a different number of customers (denominator), the calculation Mr. Stephens performed is mathematically incorrect; fractions cannot be averaged together with different denominators. The correct calculation should have been made by adding all the customer minutes of interruption for each system divided by the total number of customers each system serves. As such, any conclusions or implications Mr. Stephens has made using his reliability calculations have no merit and should be discarded. Additionally, the Company provided a comparison of 4.8kV and 13.2kV system reliability in the March 22, 2023 Technical Conference (Deol, 2T 264-65; Exhibit MEC-81 page 7).

In summary, Mr. Stephens' proposed disallowance lacks any valid evidentiary basis. The record further reflects that the 4.8kV/8.3kV conversion projects will improve safety and reliability for customers and are otherwise reasonable and prudent. Therefore, cost recovery should be fully approved.

5. System Loading.

The Company agrees with the PFD's recommendation for cost recovery on this issue, but reiterates its concerns regarding the "disallowance" of CWIP in rate base. As previously explained, the Company projects not in service in the projected test period are in CWIP but have no net revenue requirement because of the AFUDC offset. The Company agrees with the PFD only to the extent that it recommends cost recovery, and otherwise maintains that it properly supported the projects in this category, as indicated above and further detailed on the record.

c. Technology & Automation.

Technology & Automation projects and programs are tightly linked to grid modernization and include investments that develop capabilities in grid observability, analytics and computing, controls, and communications. They meet current grid needs and provide immediate benefits to customers. They also lay the foundation for grid modernization and are necessary to support increased adoption of distributed energy resources (DERs) and electric vehicles (EVs). See Exhibit A-12, Schedule B5.4, p 12; Exhibit A-23, Schedule M6; (Hill, 5T 2766).

1. Grid Automation Telecommunications.

The Grid Automation Telecommunications program includes installation of a more modern telecommunications system with sufficient bandwidth to support all anticipated usage and growth discussed in the Company's DGP, providing improved reliability and increased cybersecurity for a modern electrical system. (Hill, 5T 2769-74).[89] It is foundational to other grid technology and

[89] Robust and secure communications channels are foundational for a modern and advanced grid. Telecommunications is so critical that the Department of Energy has included it as a foundational infrastructure investment in their Modern Distribution Grid report which is known in the industry as the DSPx. Participants in the development of the DSPx

automation investments and is the backbone of data communications which allow other devices to be used.

The Commission previously approved a partial disallowance for this program based on the pace of the Company's spending but added that "if spending occurs above the amount approved in the instant case, the company has the ability to submit reasonable and prudent costs for approval in a future case" (November 18, 2022 Order in Case No. U-20836, p 14).

Supporting that stated Commission intent, Company witness Hill testified that upon full implementation, the Company will have upgraded and installed approximately 630 miles of fiber and 30 routers for approximately 400 substations and other critical locations under the program (5T 2760-61). The PFD found that "DTE has failed to support the reasonableness and prudence of its decisions," apparently because this full implementation is more than the 500 miles of fiber that the Company indicated that it planned to install in the next five years in Case No. U-20836 (PFD, p 309), and concluded:

> [S]ince the Commission approved the project at the 500-mile level, this PFD finds that allowing DTE to continue the project through the bridge period to undertake the scope of the undertaking presented in Case No. U-20836 would be appropriate, while recommending denial of the test year projected spending, and further requiring DTE to provide a proper analysis of alternatives before approving any further extensions of its fiber network. [PFD, p 311.]

The Company agrees that bridge period spending should be fully approved, but disagrees with the PFD's characterization that this would cover the "scope of the undertaking presented in

included public regulators, utilities and industry experts such as IEEE, EPRI, and EEI. The Company's Subject Matter Experts (SME's) are following these industry guidelines in developing and deploying grid telecommunications investments (Exhibit A-38, Schedule CC2). Many devices on DTE Electric's system, however, are either not connected for remote monitoring and control, or are connected through a communication network that is not fully integrated. The Grid Automation Telecommunications program includes installation of a more modern telecommunications system with sufficient bandwidth to support all anticipated usage and growth discussed in the Company's DGP, providing improved reliability and increased cybersecurity for a modern electrical system. (Hill, 5T 2769-74).

Case No. U-20836" because that planned undertaking was 500 miles in five years, as indicated above (See also, November 18, 2022 Order in Case No. U-20836, p 138, reflecting the Company's "plans to install approximately 500 miles of fiber and 30 routers for 230 substations and other critical locations under the program in the next five years"). The Company also maintains that spending should be fully approved for the projected test year, and that it has already properly responded to suggested alternatives and otherwise explained why the program is reasonable and prudent, and should proceed with full funding.

More specifically, in response to MNSC witness Stephens' proposed disallowances,[90] the Company presented ample evidence supporting the need for these telecommunications upgrades. The Company's SMEs have also performed extensive analysis on the use of fiber optic versus wireless communications options and demonstrated the value of the upgrade. (Hill, 5T 2801, 2806; Exhibit A-38, Schedules CC1 and CC2).

While the Company does use them in some areas and applications, wireless carriers do not offer full coverage for data across portions of the Company's service territory and have different levels of service quality and bandwidth inside the areas that they do serve. Wireless carriers also typically have a cost to build out their network infrastructure, so the Company would have to pay an upfront cost for network extension, and then continue to pay costs for leased services. (Hill, 5T 2802). See also Exhibit MEC-121, reflecting the Company's experience in having to pay both wireless carrier build-out and ongoing service fees for connecting a wind park.

[90] AG/MNSC witness Stephens proposed disallowances of $17,508,000 in the bridge period ending November 30, 2023, and $17,047,000 in the projected test year (6T 3401), concluding that "the wireless networks offered by public carriers are now so reliable and secure (not to mention more likely cost-effective) that police and fire departments have started using them . . . In my opinion DTE has not satisfied its burden to prove that its decision to expand its communications network through fiber optic ownership was prudent" (6T 3400).

Even when wireless service is available, it is not as reliable as fiber optic cable because wireless communications are subject to dead zones or poor reception inside of buildings. Wireless is also optimized for voice traffic and streaming video traffic, which can tolerate significant amounts of data loss without losing the intent of the communications. In contrast, the transfer of data is critical to utility operations and cannot be lost in transmission. To ensure these critical communications are delivered and received without service interruption or buffering issues, the Company selected fiber optic cable. (Hill, 5T 2803). Even Mr. Stephens acknowledged the Company's critical and growing needs and that he "[doesn't] disagree that the need for utilities to communicate with their substations and field equipment will grow in coming decades . . . These communications can be critical to recording equipment operating status and circuit conditions, and to executing and validating commands to operate equipment equipped with remote control capabilities" (Stephens, 6T 3397-98).

Another reliability factor that the Company considered is that wireless carriers upgrade their technology at their own discretion, based on their own needs, which could negatively impact the Company (Hill, 5T 2803). Mr. Stephens dismissed this concern, stating that "The typical utility concern over technological obsolescence ignores the fact that every generation of cellular technology since 3G has been backwards compatible." (6T 3399). This is incorrect. For example, the Company had to redesign and invest in a new AMI meter mesh backhaul at a cost of nearly $35 million as a result of public cellular wireless carriers phasing out of 3G cellular. (Hill, 5T 2804).

Furthermore, wireless technology is also still prone to security risks such as hacking that is less likely to occur in fiber optic cable networks. Having multiple users and shared traffic on wireless networks makes the networks inherently less secure than a dedicated network. (Hill, 5T 2804).

Mr. Stephens' indication that wireless is good enough for police and fire departments, and by extension it is "good enough" for the Company, neglects that police and fire departments have different communication needs than utilities. Much of police and fire wireless usage is for voice communications to remote vehicles with limited data needs, much of which can be buffered or delayed. Data transfers are not required to be on a second-by-second basis like utility SCADA. Also, in the case of dispatch centers and critical facilities where bandwidth and resiliency are paramount, police and fire best practices are to install fiber and have multiple redundant options as backup. Wireless is also not a legitimate option for future utility use cases such as dynamic protection. (Hill, 5T 2805).

Therefore, grid automation telecommunications are a reasonable and prudent investment that should be fully approved.

2. Distribution Automation, including Substation Automation.

DTE Electric's grid investments in Distribution Automation[91] have unfolded over the past several years.[92] Substation automation projects involve control panel replacements with upgraded, standardized relays, installation of Remote Terminal Units (RTU), incorporation of the RTUs and automation controls into the same substation network, and breaker replacements as needed. The

[91] The Department of Energy (DOE) report "Distribution Automation: Results from the Smart Grid Investment Program," published in September of 2016, states: "Distribution Automation (DA) uses digital sensors and switches with advanced control and communication technologies to automate feeder switching, voltage and equipment health monitoring; and outage, voltage and reactive power management. Automation can improve the speed, cost, accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers" (Hill, 5T 2774).

[92] Today, roughly 32% of general-purpose substations and 25% of the distribution circuits in DTE Electric's territory have SCADA monitoring and control. Approximately 5% of the distribution circuits have automatic loop schemes, which can automatically transfer sections of the circuits onto adjacent circuits when an outage is detected. The Company is strategically implementing Distribution Automation to maximize customer benefits. The scope of work for 2022 included the design of full SCADA control and monitoring of one substation and development of standards and processes that can be utilized to accelerate the installation of distribution automation equipment across the electrical system. These new standards will be applied in 2023 and 2024 to upgrade substations and rebuild circuits. (Hill, 5T 2774-77).

automation technologies installed on substations will also be linked to the ADMS for enhanced applications. (Hill, 5T 2776).

AG witness Coppola proposed that the Commission "remove a total amount of $27,916,000 from the Company's forecasted capital expenditures with $4,583,000 ($5,000,000 x 11/12) for the 11 months ending November 2023, and $23,333,000 for the 12 months ending November 2024 (45), suggesting that it is "not possible . . . to connect work to be performed in 2023 and 2024 to the $30 million forecasted to be spent in those two years" (Coppola, 6T 3656).

The PFD agreed with the AG, finding that "DTE has failed to support the reasonableness and prudence of this program" and "DTE has not justified this program and the requested bridge and test year funding should not be approved" (PFD, pp 314-15).

The Company disagrees because Mr. Coppola combined the total investment into $30 million, but the Company more granularly forecasts $5 million of expenditures in 2023, and $25 million in 2024 (Exhibit A-12, Schedule B5.4, page 12, line 9). The Company also provided a scope of work and construction schedule (Exhibit A-23, Schedule M6, pages 19-22) that creates a clear path from the investment plan (Exhibit A-23, Schedule M6, page 34) to the construction of field assets (Exhibit A-23, Schedule M6, pp 31, 34.) (Hill, 5T 2807-2808).

Mr. Coppola further attempted to support his proposed disallowance by asserting that "[t]here is also no evidence presented to show how the target substations are having a material impact on power outages or how the planned upgrading and installation of new technology will solve any problems" (6T 3656). Company witness Hill's direct and rebuttal testimony explained that the Company currently has limited SCADA capabilities inside its substations, which limits the ability of system operators to remotely troubleshoot and reroute power around a grid disturbance, which can directly impact the amount of time a large group of customers is out of power. Deploying

automation technology solves this problem because it will allow the Company to operate substation equipment remotely, instead of having a substation operator dispatched and travel to the location to resolve issues, resulting in reducing the amount of time customers are without power (outage duration time). (Hill, 5T 2776, 2808-2809).

The PFD also incorrectly claims that the Company did not provide a clear scope of work for the project (PFD pp 314-315). As shown in Exhibit A-23 Schedule M6, page 32 of 158, a detailed scope of work was provided. The scope actually included the building of the trailer which the PFD itself specifically acknowledges (PFD pp 314-315). Thus, the Company has supported its funding request, including how and when the funds will be used, and benefits to customers. This demonstrates that the investments are reasonable and prudent, and should be approved.

3. Non-Wires Alternatives (NWA) Pilots.

In its Order regarding distribution planning requirements, the Commission advised that it "expects to be presented with 'a robust suite of NWAs that may be evaluated for prudency as possible programs.'" (August 20, 2020 Order in Case No. U-20147, pp 43-44, quoting Case No. U-20561, p 112).[93] Accordingly, the Company in the 2021 DGP developed a suite of NWA pilots to address circuit or substation overload concerns to help delay or offset traditional grid upgrades, and further developed plans to implement those pilot projects and included them in the U-20836 rate case. The Commission's November 18, 2022 Order in Case No. U-20836 provided feedback on each pilot (summarized in Exhibit A-12, Schedule B5.4.9, with the Company's response).

[93] NWAs are defined in section 4.3 of the DGP (using Staff's definition that the Commission adopted in its August 20, 2020 Order in Case No. U-20147, pp 11, 41) as:

> An electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades.

There are nine NWA pilots as shown in Table 5 of Mr. Hill's direct testimony (at 5T 2781). This includes the first NWA pilot at Hancock substation (which was completed as discussed in Case No. U-20836), and the remaining pilots as described in Exhibit A-12, Schedules B5.4.1 to 5.4.7; Exhibit A-23, Schedule M6; Exhibit A-23, Schedule M7 (DGP, section 12.7, starting at page 400)). The pilots the Company is currently pursuing are building blocks, which together will form a foundation for the development of future NWA projects. (Hill, 5T 2779-80).

The PFD states:

> At the outset of this discussion, this PFD notes that most of these projects are not slated to be finished within the test year. The following projects by corresponding line number on Schedule B5.4, pages 19 and 20 are outside the test year in this case: lines 162 (Battery Trailer), 164 (Fisher), 165 (Port Austin), 166 (Veridian), 167 (Small Solar and Storage Testbed), and 168 (EV Charging Demonstration). This PFD recommends that those projects be excluded from rate base and not approved for the reasons explained in subsection a above. [PFD, p 317.]

As previously explained, projects not in service in the projected test period are included in CWIP but have no net revenue requirement because of the AFUDC offset. The PFD's recommendation that "projects be excluded from rate base" neglects that CWIP is in rate base, as reflected in Exhibit B of the PFD.

The PFD also "finds Staff's recommendation reasonable for the company to be directed to meet with Staff periodically regarding its current suite of pilot programs and similar programs under development and to provide it with information as requested" (PFD, p 317). The Company agrees to meet with Staff prior to implementing future NWA pilots and at a set frequency through the pilot's term. The Company is open to discussions with Staff to understand the full intent of the other three (mobile battery) recommendations. As further discussed below, the Company is looking at mobile battery pilots to support a variety of potential grid needs. There is no need for a directive from the Commission (Hill, 5T 2822-23).

Although the PFD did not further discuss certain NWA projects or offer any further recommendation of them, the Company further presents the following for purposes of a full discussion and in support of recovery.

AG witness Coppola proposed disallowances are based on four incorrect and unsupported assertions regarding NWAs and the Company meeting pilot guidelines, as outlined below.

1. Alternatives: Mr. Coppola asserted that "[m]ost of the pilots have not been analyzed against other less costly and reliable alternatives to establish that the NWA projects have a reasonable chance of being economically viable." (6T 3667). To the contrary, the Company presented alternatives for each pilot in Exhibit A-12, Schedule B5.4.1 to B5.4.9, section 3, subpart c, and in Exhibit A-23, Schedule M7. Many of these alternatives were more costly and therefore not chosen, as further discussed below. (Hill, 5T 2811). Updated analyses, which include data gained from the pilots, can be made once the pilots are completed.

2. Scalability: Mr. Coppola asserted that "it is obvious that the NWA option is too costly and unworkable at any scale" (6T 3667). To the contrary, some of the NWA options that the Company is pursuing at the current stage of implementation appear to be very cost effective, such as the Fisher project. Mr. Coppola also provided no analysis to support his assertion that it is "too costly" and neglected to mention that the Company proposed pilots are intended to address the August 20, 2020 Order in Case No. U-20147, and answer questions regarding costs, benefits, and scalability (Hill, 5T 2776, 2811-12).

3. Guidelines: Mr. Coppola included guidelines for pilots from the February 4, 2021 Order in Case No. U-20645, apparently to imply that the Company is not meeting those requirements (6T 3668). To the contrary, Exhibit A-12, Schedules B5.4.1 to B5.4.9, and Exhibit A-23, Schedule M7 show that the Company is meeting the pilot guidelines (Hill, 5T 2812).

4. Decision Making: Mr. Coppola asserted that "[a]lthough the objectives laid out by Mr. Hill have merit, the actual decisions to undertake the six pilot projects fall short from sound decision making" (6T 3667). The Company agrees that the pilots' objectives have merit, but otherwise disagrees because the Company followed the U-20645 requirements to evaluate and document the pilots as reflected in Exhibits A-12, Schedules B5.4.1 to B5.4.9 (Hill, 5T 2812).

Turning to the specific pilots, the Mobile Battery Trailer pilot involves developing a mobile battery system consisting of three trailers (two DC battery trailers, and a third trailer containing an inverter and system interconnection equipment (medium voltage trailer)) to support customer restorations. The Company has provided detailed information and an update on progress that has been made on the pilot. (Hill, 5T 2783-84; Exhibit A-12, Schedule B5.4.2; Exhibit A-12, Schedule B5.4.9, p 1).

Mr. Coppola proposed a $3,762,000 disallowance based on his views regarding Alternatives and Scalability (6T 3671-72). The Company disagrees, incorporating the discussion above, and further noting that it evaluated and compared the pilot against possible alternatives presented in Exhibit A-12, Schedule B5.4.2, section 3, subpart c. The Exhibit further reflects that the emission-free mobile battery can be readily available to support system emergencies and planned maintenance and can be easily moved for use at specific locations, thereby reducing outage restoration time for customers and supporting system reliability. The pilot will assess if mobile battery technology is cost effective compared to the Company's traditional portable equipment and other restoration methods. If mobile batteries are cost effective, then the Company can scale up their use (Hill, 5T 2814).

The Fisher Load Relief pilot includes geo-targeted deployment of Demand Response (DR) and Energy Waste Reduction (EWR) to relieve a portion of the load concerns at the Fisher

substation (Hill, 5T 2786-87; Exhibit A-12 Schedule B5.4.4). The Company provided detailed support and an update on progress that has been made on the pilot (Hill, 5T 2786-89; Exhibit A-12, Schedule B5.4.4 and Schedule B5.4.9, p 2). No party proposed a disallowance for this pilot.

The Port Austin Load Relief pilot involves solar and storage to address concerns with the Port Austin substation being above its firm rating. The Company has provided detailed support, and an update on progress that has been made on the pilot (Hill, 5T 2789-90; Exhibit A-12, Schedule B5.4.5; Exhibit A-12, Schedule B5.4.9, p 3). Exhibit AG-1.76, p 7 further supports the pilot by reflecting that storm damage could be isolated and customers could continue to be served with a microgrid.

The Company is also exploring opportunities for federal funding from the Infrastructure Investment and Jobs Act (IIJA) to expand NWA deployments at O'Shea (which the PFD properly finds should be approved at PFD, p 319, along with Omega Load Relief at p 321) and Port Austin by incorporating innovative new technologies like adaptive networked microgrids to increase customer benefits from the deployed assets (Hill, 5T 2794-95; see also Kryscynski, 3T 396-99, regarding future opportunities for IIJA grants to fund infrastructure investments).

The Veridian pilot has three aspects (Underground Residential Distribution (URD) Loop; System Upgrades; and Microgrid) to accommodate load growth for the Veridian all-electric residential development in Ann Arbor. The Commission previously approved cost recovery but indicated that it would continue to monitor costs as the project proceeds and additional details are available (Case No. U-20836 Order dated November 18, 2022, p. 156). The Company has provided

details, and an update on progress that has been made on the pilot (Hill, 5T 2790-92; Exhibit A-12, Schedule B5.4.6; Exhibit A-12, Schedule B5.4.9, p 4).[94]

Mr. Coppola proposed a $7,935,000 disallowance, indicating doubts about the need for system upgrades (6T 3677-79). On the contrary, there is a very real need for the system upgrade. Although the Regent substation itself is not currently overloaded, the specific circuits feeding the Veridian development cannot support the requested service. Also, although the solar and storage assets paid for by the developer will offset the development's electric demand, the Company must be able to provide service in the event of low to nonexistent solar generation or storage availability. The larger wires also provide voltage support in the event of high solar output, where customer generation supplies energy to the grid.[95] The system upgrades also do not benefit only the Verizon development, because all customers on each upgraded Regent circuit will experience a reliability improvement via upgraded poles, wires, and associated equipment. The work will also prepare the area for future conversion to 13.2kV by pre-converting the area to current design standards. Thus, the circuit upgrades ($4.3 million of the Veridian pilot investment) are not only necessary for the Veridian pilot, but also for the Regent area conversion (Hill, 5T 2817).

[94] The AG's Initial Brief, p 53, asserted that the Veridian pilot "is an example of the AG's concerns already coming true – DTE started down the road in U-20836 and is already asking for greater costs." The AG's assertion mischaracterized the circumstances. The Company sought limited cost recovery relating to the time period at issue in Case No. U-20836. The Commission approved cost recovery ("namely $1.53 million for the 22-month bridge period and $4.95 million for the projected test year") and further stated that it "will continue to monitor these costs as the project proceeds and additional details are available and commends the company for working with customers to pursue this type of project" (November 18, 2022 Order in Case No. U-20836, p 156). Thus, there is nothing amiss with the Company seeking "greater costs" for a subsequent time period for an ongoing project.

[95] The same response generally applies to Mr. Coppola's assertions that these customers would be "electric power self-sufficient with only temporary use of power from the electric grid. Therefore, any additional power draw from the substation should be limited and intermittent" (6T 3677). These generalized assertions lack support and do not consider the impact of the load under various scenarios, such as reverse power flow from the customer DER, low state of charge of customer-owned storage, and solar availability. The assertions also do not indicate any consideration for the need for controls to coordinate the resources. (Hill, 5T 2818-19).

Mr. Coppola further suggested that the installation of a utility battery "seems to be highly duplicative of the storage batteries that customers have within their own houses" (6T 3677). The suggestion is incorrect because the utility battery provides additional storage for solar energy and is not duplicative. The utility battery also serves as the grid-forming inverter for the microgrid that the rest of the customer-owned resources can synchronize to, so it is necessary for this pilot (Hill, 5T 2819).

Mr. Coppola further suggested that there is a risk that the Veridian development might not move forward. On the contrary, the development is moving forward. Infrastructure, including roads, is under construction. (Hill, 5T 2818).

The EV Charging Demonstration at ACM (American Center for Mobility) concerns the Company's support for implementing the Delta Power Electronics DC Xtreme 400KV fast charger and understanding the impacts of high-powered charging on power quality. The Company has provided detailed information and an update on progress that has been made on the pilot, (Hill, 5T 2792-94; Exhibit A-12, Schedule B5.4.7).

Mr. Coppola proposed a $5,451,000 disallowance, asserting that "[i]t is not clear what these amounts will be spent on given that ACM or Delta is providing, or should be providing, the charger and technology to be tested" and "[i]t is not fair or reasonable for the Company to perform testing on still experimental technology on the backs of its utility customers" (6T 3680-81).

The Company disagrees with this disallowance because the Company provided significant evidence showing how the funding will be invested, and how the investment will benefit the Company and its customers. (Hill, 5T 2792-94, 2820; Exhibit A-12, Schedule B5.4.7; Exhibit A-23, Schedule M6, pp 71-74; Exhibit A-23, Schedule M7, pp 415-416; Exhibit A-38, Schedule CC3). In summary, the ACM is a multi-partner facility to test the grid component needed to support DC

fast charging, autonomous vehicles, and other mobile technology. Specific investments include a utility gateway and communications portal to enable charge management, a control algorithm for the Delta Extreme fast charger, cyber security interfaces and controls, sensing and monitoring devices, and monitoring and control algorithms for in-road inductive charging. Benefits of the investment include learning about the technology that will be needed in the future for electrification, while being supported by DOE funding. Specific benefits include the development of the delta charging hardware that provides extreme fast charging capabilities, and a solid-state transformer technology that allows direct connection of these high-power chargers to distribution lines. (Hill, 5T 2821).

In summary, the Company developed a "robust suite of NWAs" in response to the Commission's stated expectation in Case No. U-21047. The Company has also responded to direction that the Commission provided on each pilot in its November 18, 2022 Order in Case No. U-20836 (summarized in Exhibit A-12, Schedule B5.4.9). The Company also refuted the AG's criticisms, further demonstrating that its pilots are reasonable, prudent, and well-supported. Therefore, the Company's requested cost recovery should be approved.

4. Distributed Energy Resources Management System (DERMS).

The PFD "notes that this project is yet another project that has an in-service date beyond the test year, in this case, 2035 as shown on line 170 of Schedule 5.4, page 20, and has been assigned to CWIP. As discussed in section a above, this project should be excluded from rate base and not approved because DTE is not seeking any revenue in this case for that project" (PFD, p 323). As previously explained, projects not in service in the projected test period are included in CWIP but have no net revenue requirement because of the AFUDC offset. The PFD's recommendation that

"projects be excluded from rate base" neglects that CWIP is in rate base, as reflected in Exhibit B of the PFD.

The Company further notes that AG witness Coppola recommended disallowances of "$4,253,000 for the 11 months ending November 2023, and $2,715,000 for the 12 months ending November 2024," stating that "[i]t appears that no Company witness filed testimony to justify the business reasons for this project," and "[i]t is evident from the limited information provided by the Company that this project is still in the early stage of development and premature to include in rate base in this rate case" (6T 3681-82).

The Company disagrees because Exhibit A-23, Schedule M6 supports the near term need for the DERMS project. Additional supporting evidence is in Exhibit A-23, Schedule M7, section 12.8.9 DERMS module, page 420, and section 12.8.10 DERMS module modeling, page 420. The Company needs DERMS functionality to assist in managing the significant and growing number of Distributed Energy Resources (DERs) on its distribution system. Contrary to the AG's claims, the project is not "still in the early stage of development." Rather, the Company has been actively pursuing the project since 2021 and is executing on it in 2023 and 2024 as confirmed by the schedule in Exhibit A-23, Schedule M6 p. 82. The evidence demonstrates that the project is reasonable, prudent, and therefore cost recovery should be approved (Hill, 5T 2824-25).

5. Work Management and Scheduling.

AG witness Coppola proposed that the Commission "remove $16,281,000 from the Company's forecasted capital expenditures with $6,160,000 from 2022, $6,736,000 from the 11 months ending November 2023, and $3,385,000 from the 12 months ending November 2024," stating that "[i]t appears that no Company witness filed testimony justifying the business reasons

for the project," and "[f]rom the brief information provided, it is not possible to establish the need to undertake the upgrades and whether they are justified" (6T 3682-83).

The PFD declined to reach a conclusion on the issue, but suggested that if it did, then there could be some disallowance:

> This PFD first notes that the work management and scheduling upgrades project is not scheduled to be completed until 2035, and DTE has shown it remaining in CWIP through the test year, on line 173 of Schedule B5.4, page 20. Consistent with the discussion in section a above, this PFD recommends that the project be excluded from rate base and not approved.
>
> This PFD further notes that DTE has provided no cost estimate for this project over the next dozen years, limiting its presentation in Schedule M6 to the 2022-2024 spending, totaling $16.5 million, as shown on page 94 of that schedule. Mr. Coppola is correct that the project description is vague, looking more like the IT project descriptions that read like to do lists compiled on an annual basis. [PFD, p 324.]

As previously explained, projects not in service in the projected test period are included in CWIP but have no net revenue requirement because of the AFUDC offset. The PFD's recommendation that "projects be excluded from rate base" neglects that CWIP is in rate base, as reflected in Exhibit B of the PFD.

Here again we also find evidence of the PFD presenting an irreconcilable conundrum through various suggestions that the Company provides too much information concerning its future plans, criticisms of the Company for transparently explaining its longer-term intentions and justifications (as frequently requested by others), or complaining that a project description is too "vague." Mr. Coppola's criticisms are similarly inconsistent and therefore reliance on those opinions cannot support a lawful Commission Order. 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." The record as whole demonstrates that the PFD

(and several parties) demand contradictory standards. In a nutshell, the PFD tries to do too much and, in doing so, perpetuates an inaccurate view of the purpose for this proceeding.

Our Supreme Court aptly described the bounds of utility regulation in *Union Carbide v. Public Service Comm*., 431 Mich 135; 428 NW2d 322 (1988) as follows:

> The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions. "It must never be forgotten that while the State may regulate with a view to enforcing reasonable rates, it is not the owner of the property of public utility companies and is not clothed with the general power of management incident to ownership." [citations omitted]

The Company further maintains that it supported the need for, as well as the reasonableness and prudency of, the project. See Exhibit A-23, Schedule M6, p 94, providing a detailed construction schedule; Exhibit A-23, Schedule M7 DGP, section 12.9.2 providing additional information. Company witness Hill also quoted and further discussed the business reason for the project from page 426 of Exhibit A-23, Schedule M7 DGP. The project is reasonable, prudent, and supported, so cost recovery should be approved (Hill, 5T 2826-27).

6. Load Forecasting and Analytics.

AG witness Coppola proposed that the Commission "remove the total amount of $13,912,000 from the Company's capital expenditures with $1,951,000 from 2021, $2,536,000 from 2022, $5,047,000 from the 11 months ending November 2023, and $4,378,000 from the 12 months ending November 2024," asserting that "[i]t appears that no Company witness filed testimony justifying the business reasons for this project," "[n]o description is provided about the Company's current load forecasting system and why it cannot handle new forecasting needs," and "[f]rom the brief description provided, it is not possible to establish the need to undertake the projects nor whether they are justified" (6T 3684-85). Mr. Coppola seems to imply that such

information must be set forth only in witness testimony. This assertion is incorrect. Evidence may also be provided through admitted exhibits. For example, R792.10429(1) provides "*When the evidence consists of technical matters or figures so numerous so as to make oral presentation difficult to follow, it must be presented in exhibit form, supplemented and explained, but not duplicated by testimony.*" Thus, the Company may include evidence regarding some larger projects in exhibit form in order to keep testimony volume reasonable and for ease of reference. In this case, each line item in Exhibit A-12 B5.4 is supported in Exhibit A-23 Schedules M3-M6 including precisely the information Mr. Coppola inaccurately alleges the Company failed to provide.

The PFD did not reach a conclusion on the issue, but suggested that if it did, then there could be some disallowance:

> This PFD notes that Schedule B5.4, page 20, line 176 shows that this project will not be completed until 2027; Schedule M6, page 106 confirms that the project will not be completed by the end of 2024. This project should be excluded from rate base and not approved, consistent with the discussion in subsection a above. This PFD also notes that Schedule M6 only provides spending totals through 2024; it does not contain an estimate of the total cost of the project through December 2027. [PFD, p 326.]

As previously explained, projects not in service in the projected test period are included in CWIP but have no net revenue requirement because of the AFUDC offset. The PFD's recommendation that "projects be excluded from rate base" neglects that CWIP is in rate base, as reflected in Exhibit B of the PFD.

The Company further maintains that it appropriately supported the project and responded to AG witness Coppola's proposed disallowances. After quoting the business reason, Company witness Hill further quoted Exhibit A-23, Schedule M7 DGP, pages 435-36, which explains why the Company's current load forecasting system cannot handle new forecasting needs. Additional detail is provided by Exhibit A-23, Schedule M7, section 4.2 Forecasting, beginning on page 65.

The project is reasonable, prudent, and supported, so cost recovery should be approved (Hill, 5T 2829-30).

7. Advanced Distribution Management System (ADMS): NMS and DMS/OMS.

The Advanced Distribution Management System (ADMS) is an advanced operating technology platform that is essential to DTE Electric's grid modernization efforts to improve system reliability and operational efficiency. It is comprised of software and associated hardware that is substantially improving DTE Electric's ability to manage the flow of electricity from the point of generation to the point of delivery, to monitor the condition of the grid, to safely operate it, and to respond to emergency conditions and outages more quickly. DTE Electric has replaced several systems that were at end of life with the following components that comprise ADMS: Generation Management System (GMS); Energy Management System (EMS); Outage Management System (OMS); Distribution Management System (DMS); and Network Management System (NMS). Customer benefits include reduced outage durations and better communications on the status of their electric service and expected restoration times (Reterstorf, 5T 2899-2904; See also section 12.1 of the DGP (Exhibit A-23, Schedule M7)). The Commission previously found "this capital expense amount to be reasonable in light of the significant improvements in reliability, integration with distribution resources, and substation outage risk that are offered by ADMS, and the fact that it is becoming commonplace in the industry" (Case No. U-20162 Order dated May 2, 2019, p. 29).

The Company successfully completed GMS implementation in 2018, followed by EMS in 2019, and NMS in 2020. In addition, OMS and DMS (and supporting interfaces for work management and customer systems) went live in February 2023 (Reterstorf, 5T 2908, 2918).

The PFD has a section discussing NMS (PFD, pp 296-99), which does not offer any recommendation (contrary to MCL 24.281(2)), but appears to propose disallowance of NMS in Appendix E page 1, line 31. As such, the Company submits the following discussion supporting its requested recovery**.**

The initial NMS phase completed in 2020 set the foundation for the Company to maintain high-quality Network Model data. Building on the successful NMS launch, and as part of the recent grid modernization efforts, the Company determined that it needed additional investments in the Network Model data quality to support the advanced planning tools and processes for scenario planning targeting four areas. These areas are: (1) Common Platform; (2) Network Model Enhancements; (3) Grid Model Analytics; and (4) Asset Data Integrations. Additional investment has supported, and will continue to support, further development of high-quality data in the Network Model (Reterstorf, 5T 2909-11, 2916).

In Case No. U-20836, the Commission stated that it "supports the integration of this type of advanced technology to maintain data that assists with managing and operating the grid." However, it adopted Staff's proposed disallowances totaling $1.44 million of the requested $6.3 million, reasoning that "DTE Electric did not clearly discuss how the increased cost associated with this program provides benefits to customers commensurate with the investment. In addition, DTE Electric failed to detail the criteria by which the Company decides which new technologies and processes provide the most benefit for maintaining data." (Case No. U-20836 Order dated November 18, 2022, pp. 128-29).

The Company, having understood and incorporated the Commission's feedback from U-20836 with respect to its support of this request, now seeks recovery of $1.292 million for 2021; $3.986 million for the 23-month bridge period ending November 30, 2023; and $2.9 million for the

projected test year (Reterstorf, 5T 2913; Exhibit A-12, Schedule B5.4, page 12, line 3). Ms. Reterstorf provided the current status of implementing the NMS investments in the each of four focus areas and explained that investments to date have improved the Company's operational ability to generate maps from GIS, improved the Company's load analysis ability, and enabled more accurate preventative maintenance planning. Combined with the remaining work in 2023, this investment will continue to improve data quality as reflected by specific metrics in each focus area (Reterstorf, 5T 2913-16).

AG witness Coppola recommended that the Commission "disallow recovery of the $8,178,000 in capital spending that the Company seeks to recover in this rate case by removing capital expenditures of $1,292,000 from 2021, $1,328,000 from 2022, $2,658,000 for the 11 months ending November 2023, and $2,900,000 for the 12 months ending November 2024" (Coppola, 6T 3660). He essentially reasoned that if the new functions are important, then they should have been included in the original scope of the project (Coppola, 6T 3658-59).

The Company disagrees with the AG because grid modernization is by necessity a multi-year program that inherently benefits from new ideas and technical advancements. The Company continues to learn while identifying needs and opportunities. As the Company explained additional investments were identified during the Distribution Grid Plan process with support from an external consultant (5T 2916). The Company maintains that the additional NMS investment provides benefits of more accurate load and planning analysis, improved responsiveness to customer adoption of new technologies such as DERs and EVs, improved reliability, and improved preventative maintenance processes. These benefits demonstrate that the costs are reasonable and prudent (Reterstorf, 5T 2909-12, 2944).

Mr. Coppola importantly did not dispute the benefits of the investment, but instead simply took issue with the timing of it. This is not a reasonable basis to disallow the costs. Instead, it is reasonable to expect that the ADMS data requirements would evolve after the initial NMS scope was completed, especially given the timing of the NMS implementation relative to the later OMS and DMS components. New data and/or data characteristics will be required on an ongoing basis as the Company (and the utility industry) continue to change and respond to evolving demands such as DERs and EVs. Grid needs are dynamic, and the tools to support grid reliability and grid modernization need to adapt and develop to support these emerging grid needs (Reterstorf, 5T 2945).

The grid and grid controls are fundamentally geo-location based, and NMS is the fundamental electrical map that supports the both the ESOC providing control and system protection, and field operations who are both receiving and transmitting back information. Therefore, NMS must adapt to meet the Company's changing needs and customers' expectations. The additional investment includes technology to better align field conditions and maps to the digital representation of the grid, integration between asset systems, new data models to support planning and operations topology and characteristics, and advanced analytics to leverage sensor data to continuously improve the Network Model. These are reasonable and prudent investments that bring essential, real-world value to the Company and its customers. Therefore, the Company's requested cost recovery should be approved (Reterstorf, 5T 2909-18, 2945-46).

In summary, the Commission should approve cost recovery because the benefits that the additional NMS investment provides (more accurate load and planning analysis, improved responsiveness to customer adoption of new technologies such as DERs and EVs, improved

reliability, and improved preventative maintenance processes) demonstrate that the costs are reasonable and prudent (Reterstorf, 5T 2909-12, 2944).

Turning to OMS and DMS, the Company completed all pre-go-live milestones and the applications went live in February 2023. OMS/DMS funding has been submitted in prior cases. The total sought from 2018 through 2023 is $91.1 million. Of this total, $78.9 million has already been included in rate base. The Company now seeks to recover the remaining $12.2 million (Reterstorf, 5T 2919-20; Exhibit A-12, Schedule B5.4, p 12, line 2).

In Case No. U-20836, the Commission reaffirmed that it "supports the integration of this type of improved technology to manage and operate the grid, to more effectively respond to emergencies, to modernize DG and other technologies, and to integrate multiple forms of communication." (Case No. U-20836, November 18, 2022 Order, p 124). The Commission approved disallowances of $11 million for the 22-month bridge period and $2.7 million for the projected test year, yet questioned why the Company did not hire a system integrator sooner. (*Id.*, p 125).

AG witness Coppola opposed the Company's cost recovery. The PFD agreed, stating:

> This PFD finds Mr. Coppola's recommendation well-supported and consistent with the Commission's determination [in] Case No. U-20836. DTE has provided no additional information to support full recovery beyond the amount approved in the last rate case, and concludes that it should be adopted. [PFD, p 296.]

The Company maintains that the Commission should approve the requested cost recovery based on the additional evidence submitted in this case (See Reterstorf 5T 2919-2926). In addition to the discussion above, the Company explained that based on the Company's successful prior implementations with OSI and the vendor's experience in the utility industry, DTE Electric originally made the decision to proceed with the DMS/OMS implementations without a system integrator. DTE Electric worked successfully with OSI during 2018 and 2019 to implement the

GMS and EMS on budget and ahead of schedule without a system integrator, avoiding approximately $15 million in system integrator costs. The Company was using the same vendor and approach with the OMS/DMS project (Reterstorf, 5T 2924). Furthermore, DTE Electric conducted due diligence on OSI and found that OSI had considerable and positive experience with ADMS implementation. OSI also has an established presence in the utility industry, serving nearly 20% of the world's energy supply and delivery even while utility adoption of their platform continues to grow.

Given this decision to begin without a system integrator, the Company remained ready to hire one if and when the project's continued success required it. Ms. Reterstorf explained that OMS and DMS were delayed due to delays in the delivery of the Compass mobile tool, driven largely by the complexity of the technology and restrictions imposed during the COVID pandemic. (Reterstorf, 5T 2921-23). When the first of these challenges arose, the Company moved quickly and effectively to hire an experienced system integrator. The request for proposal (RFP) was issued April 7, 2020, and the Company selected Ernst and Young. The system integrator began work in August 2020, when only two of the 14 project milestones had passed, and continued to support the project through the launch in February 2023 and into the stabilization phase (Reterstorf, 5T 2923).

DTE Electric also took other actions to reduce or eliminate cost overruns. The Company negotiated several concessions with OSI to address delays and deficiencies in deliverables. These included 400 additional user licenses at no cost, 17 additional software features at no cost, and a waiver of system support payments until August 31, 2024. DTE Electric also optimized project management processes to ensure the planned delivery dates of the OMS and DMS components were achieved (Reterstorf, 5T 2925-26).

Company witness Reterstorf summarized why the Company's request to recover capital expenditures should be approved:

> DTEE has launched ADMS including the early success with EMS, GMS, and NMS and the February 2023 launch of OMS and DMS, which included the complex integration of other customer and workforce systems. DTE Electric exercised caution and diligence in designing and launching the OMS and DMS project given its critical importance to the Company's operations. The Company acted responsibly in its project management and oversight of the vendor, including the negotiation of remedies to limit costs borne by ratepayers. And in response to the Commission's questions in Case No. U-20836 regarding the timing of the System Integrator, my testimony reinforces the prudence of DTE Electric's timing and approach to engage the System Integrator in mid-2020 to support the OMS and DMS implementation following the launch of EMS and GMS on budget and ahead of schedule. Upon initial indications that the System Integrator would be needed, DTE Electric moved quickly to engage the System Integrator to guide the project. DTE Electric's established project oversight processes allowed for such timely decision-making and actions to mitigate additional risks.
>
> Throughout this process, DTE Electric prioritized the quality and integrity of the new ADMS system, including extensive pre-launch testing and system integration efforts to replace a large number of legacy systems. Guided by the System Integrator who was enlisted early in the OMS and DMS project, DTE Electric made the correct decisions to avoid a premature system deployment that could have harmed reliability, work management processes, or customer service. [Reterstorf, 5T 2931-32.]

AG witness Coppola proposed the Commission "disallow $14,512,000 of capital expenditures from this rate case, with $3,622,000 removed from 2022, $9,937,000 from the 11 months ending November 2023, and $903,000 from the 12 months ending November 2024" (6T 3657). Mr. Coppola asserted:

> The cost overruns have not been adequately justified and at least a major portion of those incremental cost may have been imprudently incurred as a result of the Company's decision to proceed with a project with still undeveloped software and the resulting delays by the vendor to deliver the software. It would neither be fair nor reasonable for the Company to recover 100% of those cost overruns from customers. The Company needs to be held accountable for its premature decision to proceed with a suite of products that were not fully developed and proven [Coppola, 6T 3656].

Mr. Coppola's characterization of the factors that influenced the delays and cost overruns is inaccurate. Instead, the COVID-19 pandemic, delay of the next version of the Compass mobile tool and maintaining the improvements in customer outage communications were the primary drivers and the Company's actions were reasonable and prudent (Reterstorf, 5T 2921-23, 2937-38).

Mr. Coppola also criticized the Company for selecting OSI as the vendor, implying (without support) that OSI might be unsuccessful in implementing systems (Coppola, 6T 3655). To the contrary, OSI has successfully implemented ADMS at numerous utilities. (Reterstorf, 5T 2941-42). The Company's ADMS implementation also met the project's success criteria and proved itself less than one month into implementation when the Company experienced one of the largest catastrophic storms in its history. The new ADMS implementation performed beyond expected service levels under the extreme outage load. OSI considers DTE's overall implementation to be a benchmark for utilities implementing the platform (Reterstorf, 5T 2941).[96]

In summary, the ADMS, DMS/OMS investment is for essential technology that brings value to the Company and its customers, improves outage restoration response, and is the foundation for the modernized grid. The Company's prudent decisions enabled the Company to navigate project challenges, such as the pandemic and vendor delays, and still achieve a successful implementation that is regarded as a benchmark for other utilities. Therefore, the Commission should reject the PFD/AG's proposed disallowance, and approve full cost recovery (Reterstorf, 5T 2943).

[96] The Company further notes that the AG's Initial Brief, p 41, asserted that "Ms. Reterstorf fails to provide quantifiable benefits," and suggested that "this line of thinking is unacceptable" because such quantification should be done before a project is undertaken. But the AG's discovery request did not ask for that. Instead, it asked for quantification "from implementation of DMS/OMS" (past tense indicating post-implementation measurement) and the Company's response explained that "the Company's DMS/OMS implementation has not been in operation long enough to measure . . . ." (Exhibit AG-1.95, p 2). The same response essentially applies to the AG's Initial Brief, p 42, regarding NMS benefits, where the Company's discovery response explained that the Company had to operate the NMS for a reasonable period of time before it could measure the benefits (Exhibit AG-1.95, p 6).

vi. System Operating Center (SOC) Modernization: The Electric System Operations Center (ESOC) and Alternate System Operations Center (ASOC)

The System Operating Center (SOC) Modernization project is aimed at replacing the Company's outdated primary SOC and outdated backup SOC by constructing two facilities (the Electric System Operations Center (ESOC) and Alternate System Operations Center (ASOC)) designed using current industry security, resiliency, and operability standards. The SOC Modernization project is needed to address the outdated facilities and technology, space limitations, and limited visibility of telecommunication infrastructure performance (Elliott Andahazy, 3T 550-52).

Expenditures for the project were included in the Company's last three rate cases. The Commission previously "stresse[d] the need for and importance of this modernization project for system operations from a reliability and resiliency standpoint" (Case No. U-20162 Order dated May 2, 2019, p. 30). Most recently, the Company sought to recover total costs for the ESOC of $98.5 million (historic 2017-2020 plus projected 2021 and 2022 investments), which the Commission approved, stating: "The Commission finds it reasonable and prudent to approve DTE Electric's proposed capital expenditures to complete the ESOC project to meet NERC certification requirements" (Case No. U-20836 Order dated November 18, 2022, p. 137).

The Company now requests approximately $1.6 million for investments in 2022 and 2023, which are primarily used to support the development of the IT systems supporting the ESOC. Construction of the ESOC is complete, all personnel have moved into the new facility for day-to-day operations, and the record reflects numerous examples of expected benefits being realized. The Company acknowledges the Commission's indicated expectation that there would be no further capital investment in the ESOC, but it is a critical operational resource that will require incremental

investments to maintain and evolve to meet future needs (Elliott Andahazy, 3T 553-57; Exhibit A-12, Schedule B5.4, page 12, line 4).

Because the ASOC was still in pre-construction design and engineering in Case No. U-20836, the Commission found "that it is not reasonable and prudent to approve the capital costs for the ASOC at this time" (Case No. U-20836 Order dated November 18, 2022, pp. 137-38). Accordingly, Company witness Elliott Andahazy explained that the ASOC will be connected to the new Waterford service center, so the Company will be able to leverage synergies in construction and reduce overall costs closer to alignment with the initial estimates provided in Case No. U-20561. The ASOC and Waterford Service Center design is complete. Site preparation began November 11, 2022. Foundation construction began December 12, 2022 and in 2023 the project is well under way. The ASOC construction is anticipated to be complete in 2024. Therefore, based on the Commission's direction in U-20836, these capital costs are now ripe for recovery. (Elliott Andahazy, 3T 558-60; see also, Uzenski, 5T 1529-30, (discussing the Waterford project)).

Both the ESOC and ASOC facilities are well justified and should be fully funded. Due to the essential nature of the ESOC in operating the electric grid, a backup facility is required in the event the primary facility is inoperable, and the ASOC's location (approximately 25 miles from the new ESOC) will allow the Company to safely operate the grid in the case of a major adverse event at the ESOC (Elliott Andahazy, 3T 557-58). Customers will benefit in numerous ways from the SOC Modernization project, as Ms. Elliott Andahazy testified:

> Customers will benefit from the improved communications paths between resources that will be co-located in the new facilities, which will facilitate quicker and improved coordination to create and implement restoration strategies more efficiently. Plus, customers will benefit from reduced risk in disruption in operations during outage events, and faster restoration times regardless of the facility from which the System Operations organization is forced to operate. The ability to understand system conditions and dispatch resources to address issues will be greatly enhanced by the technology available in the new facilities and the

> co-location of the system Operators, Power Dispatchers, and support personnel. In addition, ESOC is more resilient and hardened to withstand adverse natural and man-made disasters, allowing electric grid operations to recover much more quickly in the event of a major catastrophe. These benefits have already started to materialize due to the utilization of the ESOC, as discussed earlier in my testimony, and will be fully realized once the ASOC is complete. [Elliott Andahazy, 3T 560.]

AG witness Coppola proposed that, for the ESOC, "additional costs of $2,048,000 above the previously approved amount of $98.5 million should not be included in rate base" and recommended that the Commission "remove $428,000 for 2021, $1,420,000 for 2022, and $200,000 for 2023 from the Company's proposed capital expenditures" (6T 3662). The PFD agreed, stating:

> This PFD finds that Mr. Coppola's recommendation should be adopted. . . .
>
> Ms. Elliot Andahazy wrongly construed the Commission's order [in Case No. U-2036] as some "lifecycle" bar on future investment, which it clearly was not, and wrongly equates the company's requested additional spending as "incremental investments to maintain and evolve to meet future needs" when it appears to be more of the initial project costs that would have been anticipated at the design stage. [PFD, p 303.]

The Company maintains that cost recovery is justified. In addition to the discussion above, based on the Commission's direction in Case No. U-20836, the Company investigated methods to keep the investment at $98.5 million. However, the Company was unable to properly operate the ESOC without the additional investments to support the development of the IT systems supporting the ESOC as a whole, and the new ADMS. The Company made these additional reasonable and prudent investments in good faith, as were necessary to operate the ESOC as intended. Because this additional investment was reasonably and prudently spent, its cost recovery should be approved (Elliott Andahazy, 3T 553, 605-606).[97]

[97] Mr. Coppola further suggested that the Company just presented a "rundown of activities" that were performed during events, rather than a showing of the ESOC's benefits (Coppola, 6T 3662). This is incorrect. The Company presented

Mr. Coppola further alleged that the Company did not justify "the revised total cost of $38.1 million for the ASOC project," and recommended that the Commission "remove $1,642,000 for 11 months ending 2023 and $3,258,000 for the 12 months ending 2024 from the Company's proposed capital expenditures" (6T 3664). The Company responded by explaining that the Commission should reject this proposed disallowance because it is not seeking $38.1 million for the ASOC in this case as Mr. Coppola indicates. Instead, the Company originally requested a total of $35.6 million, which included $2.84 million of contingency that the Company agrees to remove in accordance with Staff's recommendation. Thus, the Company's request is $32.76 million, which is below the original amount requested in Case No. U-20561. Mr. Coppola essentially sought a disallowance for an increase in capital investment from previous cases that the Company is not requesting here, so Mr. Coppola's proposed disallowance is unfounded. The Company's $32.76 million request is reasonable and should be approved (Elliott Andahazy, 3T 606-608). The PFD agreed with the AG, stating:

> This PFD finds the Attorney General's adjustment is appropriate and should be made, recognizing that contingency has already been addressed in this PFD. This PFD finds DTE's argument that it is not "requesting" the full $38.1 million less the $2.84 million in this case unintelligible. Ms. Elliot Andahazy stated in no uncertain terms that the company's total investment in this project is the $32.76 million, which she clearly compared to the past project total cost estimate. . . . The company's claim that the additional amount is "something that the Company is not actually requesting" either completely misunderstands the ratemaking process or is a waiver of recovery for that additional amount. DTE's failure to acknowledge the true cost of the project renders it unable to explain the apparent cost increase. [PFD, pp 305-306.]

The Company does not understand how the PFD could find its prior explanation "unintelligible." In Exhibit A-12 Schedule B5.4 page 12, line 5, columns (b), (c), (d), and (e) add

examples of the benefits that it was able to obtain due to the ESOC during specific events. These benefits included improved communication and collaboration, response times to coordinate field resources required, and faster decision-making that reduced unneeded field resources being sent to specific locations. (Elliot Andahazy, 3T 555-57, 606).

up to a total investment of $35.6 million, with an in-service date of March 31, 2024. This clearly shows the amount the Company is requesting for recovery in this case. The Company also disagrees with the PFD's further commentary, which is unfounded and suggests unlawful results. The Company further notes that the PFD apparently misconstrued a response to discovery in which the Company explained that the $38.1 million referenced in Exhibit AG-1.6, p 2 (reporting the U-20836 ASOC cost estimate) is different than the $35.6 million that the Company originally requested here because it "includes investments outside of this instant rate case" (Exhibit AG-1.73, p 3). The remainder of the response is consistent with the Company's prior explanation that it originally requested a total of $35.6 million here, which included $2.84 million of contingency that the Company agrees to remove in accordance with Staff's recommendation. Thus, the Company's request is $32.76 million, and the PFD/AG's proposed disallowance for an increase in capital investment from previous cases that the Company is not requesting is unfounded. The Company's $32.76 million request is reasonable and should be approved (Elliott Andahazy, 3T 606-608).

For all of these reasons, the PFD/AG's proposed disallowances should be rejected as unfounded and unreasonable, and the Company's SOC: ESOC and ASOC requests should be fully approved.

11. Community Lighting.

DTE Electric's Community Lighting capital expenditures were $14.8 million in 2021 and were expected to be $17.3 million for 2022 and are expected to be $15.4 million for the 11 months ending November 30, 2023, and $16.7 million for the 12 months ending November 30, 2024 (Bellini, 5T 2632-333; Exhibit A-12, Schedule B5.5).

The Commission ordered that "[i]n its next general rate case, DTE Electric Company shall provide an updated analysis of its streetlight re-lamping policy and wattage selection" (Case No. U-20836 Order dated November 18, 2022, p. 483).

Accordingly, with regard to the relamping policy, Company witness Bellini explained that the HPS Group Relamping program is intended to maintain HPS lighting levels at or above 70% of the initial lamp lumens throughout the luminaire's useful life. The only HPS lamp used in municipal settings (Lumalux Plus) has a useful life of 40,000 hours, after which the lamp approaches 70% of its initial lumen output. This equates to approximately 9.5 years at an annual burn rate of 4,200 hours. To avoid having the HPS lumen output fall below 70%, the Company established 9 years as the optimal cadence for relamping. The Company's study indicates 53% cost savings per lamp when performing proactive group relamping as compared to spot relamping in response to an outage. The Company has also determined that the program will become less cost effective assuming the continuing municipality-driven conversions of HPS lamps to LEDs. Therefore, the Company has decided to end the program at the end of 2023 (Bellini, 5T 2624-26).

Turning to wattage selection, Mr. Bellini further explained that it is important to select the appropriate luminaire because the purpose of street lighting is to provide adequate light levels, uniformity, and target contrast depending on the road classification. To ensure that luminaire output for new (not existing) roadway installations, achieves the proper level of illumination, the Company performs an in-depth photometric evaluation based on the effectiveness of a roadway luminaire achieving pre-established, application-based photometric requirements. The outcome determines

whether a new LED luminaire can achieve minimum roadway luminance and illuminance target values that comply with ANSI/IES RP-8 standards (Bellini, 5T 2633-35).[98]

MAUI proposed to reduce rate base by $5,835,192, and reduce the revenue requirement for streetlighting by $332,524, based on witness Bunch's assertion that the Company spends too much on LED luminaires. The PFD criticized the Company's evidentiary presentation (PFD, pp 336-41) and agreed with MAUI's proposed disallowance, concluding:

> This PFD finds that DTE failed to establish that it has a reasonable and prudent approach to replacing HID with LED lighting. The Commission provided DTE with the opportunity to justify its choices in this case, and DTE provided at best a confusing explanation of its processes as discussed above, with no meaningful discussion of cost built into its discussion. This PFD finds that Mr. Bunch has reasonably estimated an amount by which DTE's replacement choices exceed what appears to be a prudent and less costly alternative, and therefore this PFD concludes that DTE's LED plant balances should be reduced by $5.8 million. . . .
>
> Finally, this PFD concludes that Mr. Bunch's calculation of a disallowance of $5.8 million to reflect DTE's unjustified replacement of higher-cost LEDs is reasonable and this disallowance amount should be adopted. DTE did not dispute the accuracy of this calculation, only Mr. Bunch's reliance on the Leotek crossover chart as a reasonable baseline for lighting choices. Since DTE has not justified its more expensive lighting choices by reference to the ANSI/ISE standards or what appear to be reasonable manufacturer's recommendations, this PFD finds that Mr. Bunch's recommendation should be adopted. [PFD, pp 341-42.]

The PFD fails to appreciate and account for the fact that there are two types of conversions performed by the Company – new lighting systems and conversion of pre-existing systems. The Company maintains that it complies with ANSI/IES RP-8 standards in selecting appropriate luminaires for installation of new roadway lighting, and there is no sound basis for the recommended disallowance. The foundation of Mr. Bunch's incorrect premise that DTE Electric designs over lit roadways or recommends higher wattage LEDs than necessary, whether through

[98] ANSI/IES RP-8 is the benchmark in roadway lighting design practices used in street lighting to evaluate and select new roadway luminaire products (Bellini, 5T 2635).

installation of a new lighting system or by way of a customer requested HID to LED conversion are twofold: 1) his statement in direct testimony that (4T pp 916-917):

> ....DTE misinterprets the ANSI/IES RP-8 standards as an ***absolute*** minimum level, when in fact the standard sets a ***minimum*** average level. Stated another way, DTE aims to install luminaires that will stay above the ANSI target values even when their light output diminishes up to 30% (known as the L70 value). But the correct interpretation of the standard is a light that will average the ANSI target value over its life, not a light that will hit the target value at the end of its life (emphasis added).

and 2) a single vendor marketing/sales brochure the intent of which is to provide crossover options for matching LED lumen output for HPS fixtures being replaced at various levels of degradation depending on the number of years in service.

In response to Mr. Bunch's allegation, which misinterprets DTE Electric's application of the ANSI/IES RP-8 standard, Company witness Bellini did not state DTE Electric uses an "absolute minimum level" when performing lighting designs. Rather, Mr. Bellini stated DTE Electric's analysis will determine whether a new LED luminaire can achieve minimum roadway luminance and illuminance target values that comply with ANSI/IES RP-8 standards (5T 2635). DTE Electric does not use an ***absolute*** minimum level as Mr. Bunch claims. Rather, DTE Electric complies with the ANSI/IES RP-8 standards by using a minimum average level when performing analysis. Given this mischaracterization of Mr. Bellini's testimony, Mr. Bunch's argument should be disregarded.

With respect to the marketing/sales brochure crossover chart (Exhibit A-25, Schedule O3) published by the Company's primary LED luminaire vendor, Leotek, the chart expressly states a representative should be consulted to determine the most appropriate luminaire for the customers particular application. Novice customers may use this chart as a starting point (or data point) when gathering sales or marketing information from various manufacturers to evaluate new LED luminaire offerings. On its face, Leotek's chart is not intended to be used as a specification sheet for final selection. The chart's only objective is to match new Leotek LED luminaires with their

initial light levels to existing HPS luminaires in the field for several years and does not offer crossover LED options if the intent is to restore "out of the box" lumen output for the HPS luminaire being replaced. In other words, the conversion table is designed to replace a HPS luminaire at its current (degraded) lumen output, not its original lumen output. To replace a HPS luminaire at its degraded lumen output is inappropriate – like replacing old tires with new tires having as little tread as the old tires being replaced. "The Company understands that pre-existing streetlighting infrastructure may not meet ANSI/IES RP-8 standards and that it would be impractical and costly for municipalities to do so." Therefore, specific to HID to LED conversions, the Company's objective is to restore equivalent "out of the box" lumen output of the luminaire being replaced to match the intended lighting design of the original streetlighting system (Bellini, 5T 2635-36, 2659-60; Exhibit A-40, Schedule EE4). Mr. Bunch does not dispute the fact the LED equivalents offered on this conversion chart will be set to only match the already diminished lighting output of the HPS fixture being replaced and is absent of an equivalent LED option that restores lumen output to its original state. In other words, if the Commission were to adopt the recommendation of the PFD and Mr. Bunch, saving money would be prioritized over safety.

The PFD was incorrectly influenced by Mr. Bunch's contention that the Company overspent on unnecessarily bright LED luminaires by not just blindly following Leotek's HID to LED crossover chart (4T 918). As discussed above, the Company disagrees because the chart is intended to be used as a starting point in evaluating appropriate luminaire selection. It is closer to a marketing and sales tool than authoritative guidance or a technical standard, as reflected by a series of footnotes in the chart (Exhibit A-40, Schedule EEE5). Further, all customers also have the option

to deviate from the Company's recommended LEDs.[99] Municipalities could choose to deviate for various reasons, such as local ordinances, financial considerations, and residents' feedback. The suggestion that the Leotek chart should be accepted as authoritative guidance would impact municipalities and the Company's ability to work with them. Not having the ability to propose lighting solutions in a manner that restores converted lights to their original output would also increase the risk for an underlit roadway and set a dangerous precedent of essentially forcing the Company to adhere to a de facto standard based on a marketing/sales tool. Therefore, the suggestion that the Company adopt Leotek's crossover chart as authoritative guidance in replacing existing HIDs with LEDs should be rejected (Bellini, 5T 2636, 2660-62).[100]

The PFD states that it did not consider this evidence about municipalities' ability to choose alternatives because "Mr. Bellini's testimony regarding such choices was not presented as part of the analysis the Commission called for, and deprived MAUI of the ability to respond to the contentions" (PFD, p 341). The PFD's reasoning is flawed because the Commission did not call for this type of information. When Mr. Bunch raised an additional issue in his intervenor testimony, the Company properly responded to that new issue in rebuttal (See generally, section II above). The PFD cannot simply elect to disregard the Company's evidence and a recommendation that does so cannot form the basis for a lawful Commission Order.[101]

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[99] For new installations, the customer will acknowledge in their contract that the design does not conform with ANSI/IES RP-8 (Exhibit A-40, Schedule EE6).

[100] Mr. Bunch further asserted that "artificially high rates for LEDs and artificially low rates for many of their HID equivalents are slowing the conversion to LED" (4T 910). To the contrary, there continues to be robust and proactive conversions driven by municipalities. The Company also works with its municipal customers, including proactively making them aware of grant money. There are, however, some communities that simply prefer to keep high pressure sodium (HPS) lights rather than convert to LED. As long as this remains a tariff-approved option, the Company will continue to provide support and maintenance for them (Bellini, 5T 2655-56).

[101] Evidence cannot be disregarded simply because it stands in the way of the decision-maker's preference. Const 1963, Art 6, § 28 requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record."

12. Demand Response (DR) Programs and DTE Insight.

The only Demand Response program discussed here concerns DTE Insight. The Commercial & Industrial Battery Storage Pilot (C&I BESS) is discussed below in the pilot section. DTE Insight is a comprehensive program that centers on a mobile application (DTE Insight App) that is integrated with AMI to help residential customers monitor and manage their energy use. When paired with an Energy Bridge (EB) device, the DTE Insight program participants can obtain real-time energy information and manage connected smart devices, such as thermostats. The Company plans to manage the existing EB inventory (totaling 55,468 as of December 31, 2022) to fulfill ongoing EB requests expected for 2023 and 2024. DTE Electric is forecasting to spend $2.1 million during the bridge period of January 2022 through November 30, 2023, and $0.7 million for the projected test year period ending November 30, 2024 (Nguyen, 5T 1271-72, 1276-77; Exhibit A-12, Schedule B5.6, page 1, line 5, columns (e) and (f)).

Staff "recommends a full disallowance of the expenses requested for the DTE Insight Program. This includes $4.78 million in the 2021 historical year, $2.06 million in the bridge period, and $0.67 million in the test year ending 11/30/24" because "Staff does not believe this expense is a justified or prudent investment to pass onto ratepayers until its customer participation and usage is substantially higher" (Rogers, 7T 4664, 4666).

The Company noted that Staff relied on numbers that are generally accurate, but the presentation (See, e.g., 7T 4665) could be misinterpreted. The numbers show that customers are twice as likely to use the DTE Insight app to view their usage information ("Unique User Views" column) than going online to do so ("Customer Data Downloads" column). Therefore, the mobile application has shown to be a useful and necessary tool for customer information and engagement. Also, Insight's weekly authentication rose significantly after the Company introduced time-of-day (TOD) rates in March of 2023 (from 646 per week in the nine weeks prior to TOD rates, to 2,702

per week in the nine weeks after TOD rates). This significant increase in use is likely to continue, and addresses Staff's indicated concern about a lack of customer engagement (Nguyen, 5T 1280-81).

Staff's proposal to disallow the $4.8 million 2021 historical spend should also be rejected as this expenditure was to acquire 30,000 EB devices that are currently in inventory. The Commission previously approved recovery of these costs in Case No. U-20836. At that time, the Company anticipated a greater initial pace of customer participation. While requests for EB devices have been slower than initially anticipated, there is still an increase in participation since the approval, and the Company expects to use all of the EB devices in inventory. Therefore, recovery of those costs is appropriate. The Commission should also approve the remainder of the Company's request to continue supporting the growing number of customers for whom Insight is by far the tool of choice to help monitor and manage their energy use (Nguyen, 5T 1281).

The PFD agreed with Staff, stating:

> This PFD finds that DTE has failed to support its Insight Application expenditures for the reasons articulated by Ms. Rogers. DTE's data presented in rebuttal showing an uptick after the introduction of time of use rates does not establish sufficient or sustained interest to warrant a different conclusion. DTE's view that the Commission should authorize DTE to include in rate base in this case the EB device costs for devices that remain in inventory is unsupported by persuasive evidence that the devices will be in use in the test period. [PFD, p 347.]

The Company maintains that cost recovery is appropriate based on the evidence discussed above, including a more recent significant increase in use after the Company introduced TOD rates in March of 2023, which is likely to continue. Therefore, a full disallowance would be a disservice to those already participating in the program and those continuing to enroll.

13. Information Technology.

DTE Electric's Information Technology (IT) investment spending is part of the DTE Five-Year IT Plan, which categorizes IT capital by portfolios and investment categories (see, e.g., 5T 1826). Total IT capital spending was $158.0 million in the 2021 historical test year, and is projected to be $318.0 million for the 23-month bridge period ending November 30, 2023, and $170.5 million for the projected test year ending November 30, 2024 (Sharma, 5T 1820; Exhibit A-12, Schedule B5.7, p1, line 11, columns (b), (e), and (f). See generally, DTE Electric's Initial Brief, pp 141-47, for an overview of the Company's IT investment spending.

The PFD outlines the Commission's ever-increasing evidentiary requests, and then criticizes DTE Electric's evidentiary presentation (*e.g.*, PFD, p 354, pointing out typographical and cross-referencing inaccuracies. The Company does not dispute the existing filing requirements, but otherwise maintains that it has made significant efforts to address feedback from Staff and the Commission by providing exhibits with additional project details. DTE Electric has a robust IT capital investment planning process, which is known as the Annual Planning Cycle (APC), with output from that process included in this case. In addition to extensive testimony, Exhibit A-12, Schedule B5.7 summarizes IT capital cost by investment category and portfolio. Exhibit A-12, Schedules B5.7.1 through B5.7.9 present the capital spending in each portfolio. Exhibit A-24, Schedule N1 presents the executive summaries for each business case associated with each IT project over $250,000.[102] Exhibit A-24, Schedule N3 Revised provides a greater level of detail for each of the IT projects, presented by year and then in portfolio/project order. Schedule N3 has been

[102] There are also 42 projects with IT capital spending less than $250,000, but which are necessary investments to collectively support the IT Portfolio (Sharma, 5T 2041; Exhibit A-12, Schedule B5.7, page 1, line 18).

developed in a form recommended by Staff that allows the data to be filtered and sorted in excel version.

i. IT Projects with a Level 2 Cost Estimate

Staff proposed a 20% ($54.23 million) capital expense disallowance ($0.92 million in 2022; $22.34 million in the 11 months ending November 30, 2023; $30.97 million in the projected test year) for 124 projects with Level 2 cost estimates, reasoning that they are "more than a year before they are ready to be executed, and prior to comprehensive review, final approval, and budget allocation." (7T 4654). The PFD agreed, stating:

> This PFD finds that Staff's adjustment should be adopted, consistent with the Commission's decision in Case No. U-20836.
>
> While Mr. Sharma testified that project level cost details were provided in the company's workpapers, those workpapers are not in the record. Instead, DTE did provide hundreds of pages of documentation in Schedules N1 and N3 of Exhibit A-24, but while voluminous, those pages do not contain detail that would allow a determination as to how any of the cost estimates were prepared. DTE did not establish that its estimates are reliable within any reasonable error range. [PFD, p 360.]

The Company disagrees because, as outlined in witness Sharma's testimony and further supported by exhibits and workpapers, the Level 2 projects have obtained comprehensive review. The projects have secured approval in the financial base plan from the Technology Investment Committee. The Level 2 cost estimates are also comprehensive by cost type and phase (where applicable to the project) and have been supported by the IT architecture team. IT business case costs are estimated as part of a rigorous Annal Planning Cycle (APC) process where detailed estimates (Level 2) are developed, which include labor, software, hardware, and vendor/consulting costs. At project execution, the Level 2 estimates are further vetted and refined before transitioning to Level 3 estimates (5T 1822, 2049-50).

Moreover, Staff's proposed 20% disallowance is based on Staff equating the Level 2 cost estimates with the American Association of Cost Engineering (AACE) Class 3 estimates, and Staff used the "lower bound of -20%" as the basis for its proposed disallowance. (7T 4655). The AACE is just one method of cost estimation, and even assuming it is applicable, Staff's -20% proposal neglects that the AACE class 3 cost estimate also provides an upper bound of +30%. Also, while the Company does not agree that the Commission should apply any percentage disallowance, it would be more accurate to compare Level 2 estimates to AACE class 2 estimates with a -15% to +20% range. (5T 2048-49).

Staff also indicated a concern about the -148% to 142% range in projects that had a Level 2 cost estimate in Case No. U-20836 and a Level 3 cost estimate in this case. (7T 4655). Staff's focus on this statistic does not account for the complete picture. Approximately 61% of projects had less than 10% variation in the estimates when moving from Level 2 to Level 3, as discussed by witness Sharma. (5T 2050).

Here again we find evidence of the PFD presenting an irreconcilable conundrum through various suggestions that the Company did not admit enough evidence into the record concerning its future plans (even though it also disclosed additional information through the decades-old convention of submitting "workpapers" in a rate case) or complaining that a project description is voluminous but does not have enough detail. 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." The record as a whole demonstrates that the PFD (and several parties) demand contradictory standards. In a nutshell, the PFD tries to do too much and, in doing so, perpetuates an inaccurate view of the purpose for this proceeding.

Our Supreme Court aptly described the bounds of utility regulation in *Union Carbide v. Public Service Comm*., 431 Mich 135; 428 NW2d 322 (1988) as follows:

> The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions. "It must never be forgotten that while the State may regulate with a view to enforcing reasonable rates, it is not the owner of the property of public utility companies and is not clothed with the general power of management incident to ownership." [citations omitted]

For these reasons, the PFD/Staff's proposed 20% disallowance should be rejected as contrary to the Company's supporting project level detail and to history demonstrating that the Company's overall IT investment is consistently closer to the cost estimates. (5T 2051).

The PFD "further concludes that if the Commission chooses to approve the currently proposed prepay pilot, the proposed costs should be reduced by 20% to reflect the level 2 cost estimate" (PFD, p 377). The Company maintains that the Commission should approve the PrePay pilot as discussed below in section VII. A. 3 and reject the proposed 20% disallowance for the reasons discussed above.

ii. Staff's Individual IT Project Disallowances

a. Oracle Financial Planning Tool

This project (previously the Controllers financial planning tool) will procure and implement the Oracle EPM solution for the Controller's organization, which will manage financial planning processes. (5T 1854-56). Staff recommended a complete disallowance ($2.8 million in 2022; $0.81 million in the 11 months ending November 30, 2023; and $0.19 million in the projected test year) reasoning that "Staff does not find the cost of this project to be justified, reasonable, or measurable to the benefit it would provide." (7T 4658). The PFD "finds that DTE did not support the reasonableness and prudence of its proposed expenditures for this project and that Staff's

recommendation should be adopted . . . Ms. Rogers' focus on the project cost of $3.8 million, plus annual expenses of $375,000, relative to the potential savings of what is essentially one employee is reasonable, as is her conclusion that the project cost is not justified by this potential savings" (PFD, pp 363-64).

The Company disagrees for a few reasons. First, the PFD/Staff's reasoning that cost savings is the only benefit or reason for the project fails to consider that the project will improve productivity and increase efficiency in both the short term and long term. Second, the Company completed a comprehensive review of financial planning solutions available in the market and found that the Oracle EPM provides a viable solution at the lowest cost to achieve replacement of the current unsustainable process. Witness Sharma's testimony further demonstrates that the investment is justified, prudent, and necessary (5T 1854-56, 2053).

b. Infrastructure Automation Maturity

Staff proposed a complete disallowance ($0.41 million in the projected test year), reasoning that the project "is a 'nice to have' investment, however it is not a necessity and is an imprudent cost to pass onto ratepayers." (7T 4659). The PFD "finds that DTE has failed to justify the reasonableness and prudence of this project, and Staff's exclusion of these project costs from rate base is reasonable and should be adopted" (PFD, p 366).

The Company maintains that the Infrastructure Automation Maturity project is a prudent investment because the current manual process will be automated, which will help reduce the consumption of resources at the Company, as well as reduce errors and save costs. Specifically, benefits of this investment will automate established configurations deployment to alleviate human factor errors by configuration of standards for patch deployments, this will allow for faster patch deployments (5T 1973-74, 2054).

c. Infrastructure Operations Center (IOC) Automation

As with the Infrastructure Automation Maturity project, Staff proposed a complete disallowance ($0.41 million in the projected test year) of the Infrastructure Operations Center (IOC) Automation project, reasoning that the project "is a 'nice to have' investment, however it is not a necessity and is an unjustified cost to pass onto ratepayers." (7T 4660). Staff further suggested that cost is the only consideration and "tasks will still be completed" without the project (*Id.*). The PFD "finds that DTE has not supported the reasonableness and prudence of this project, or supported its cost projections" (PFD, p 370).

The Company maintains that the IOC Automation project is a prudent investment because it is an extension of monitoring capabilities for critical remote locations that are unmonitored today. Cost-benefit is not the only driver of this investment because it is focused on operational reliability improvements. (5T 1974-75, 2054-55).

d. Changing Bill Size

This project is to standardize the size of paper on which bills are printed because bills are currently printed on a custom-size paper that is supplied by only one supplier. The implementation of this project will result in cost savings, risk reductions, and efficiencies, as explained by Company witness Hatsios. (5T 1681-82). Staff recommended a total ($900,000) disallowance ($731,000 in the bridge period; $169,000 in the projected test year), reasoning that this is a "DTE-created issue" and Staff did not see any advantage for customers. (7T 4548-49). The PFD "finds Staff's analysis persuasive and concludes that Staff's adjustment should be adopted" (PFD, p 373).

The PFD's reasoning that "Mr. Hatsios did not quantify any benefits in his direct testimony" (PFD, p 373) is true, but Mr. Hatsios quantified the customer benefits in his rebuttal testimony, which is permissible and that evidence should not be disregarded as the PFD suggests (See

generally, section II above). The conversion would reduce the cost of printed bills by approximately $300,000 per year through negotiation of more competitive paper prices, a reduction in the cost of bill envelopes, and more favorable terms from the expansion of the pool of vendors. In fact, the annual savings will continue in perpetuity justifying the investment of $900,000 which would be a simple payback of three years. Despite Staff asserting there is no advantage for customers, printing bills is a cost of operating a business and reducing the cost of printing those bills does provide an advantage to the customers.

The PFD also suggests that DTE's historical choice to print bills on non-standardized paper costs ratepayers $300,000 annually. (PFD, page 373). In this instant case, the relevant context for this investment is that the project is supported by the customer benefits of risk mitigation and reducing the cost of printing bills with the conversion. The circumstances under which the Company had decided to print the bills on non-standardized paper in the distant past should not preclude this project from being considered on the merits presented.

The Commission therefore should reject the PFD/Staff's flawed conclusion and proposed disallowance and determine that the Company's $900,000 investment is reasonable and prudent, based on the customer benefits. (5T 1783).

e. DTE Electric Utility Network (UN)

The Company will invest $0.7 million in the DTE Electric Utility Network (UN) project over the course of 35-months ending November 30, 2024, as shown on line 7 of Exhibit A-12 Schedule B5.7.4 Revised (5T 1902). The DTE Electric Utility Network project will implement the new ESRI UN product in the cloud to replace the ArcMap platform that will no longer be supported by Q1 2025. This product replacement will increase availability, recoverability, scalability, and security while enabling business process efficiency. (5T 1903).

Staff proposed a 50% reduction of this investment, reasoning that "the Company is projecting $375,000 in capital expenditures for 2023 and 2024. Staff's position is that by virtue of the two projected amounts being identical, said projections are likely preliminary and the actual expenditure amounts could be different . . . Therefore, I applied a 50% reduction . . . [which] results in downward adjustments of $171,875 for the 11 months ending 11/30/2023 and $187,500 to the test year." (7T 4415-16). The PFD "finds that DTE has not established the basis for its cost estimate for this project and thus finds Staff's recommendation reasonable and concludes it should be adopted" (PFD, p 379).

The Company disagrees because this sustainment effort is complete in detailed scoping including robust requirements documentation. The annual cost breakdown reflects the internal and external labor by resource group. The consistency in annual costs reflects a planned schedule of spending with the allocated resources. (5T 1902-1905, 2055; Exhibit A-43, Schedule HH1). Therefore, the PFD's conclusion that the Company has not established the basis for its cost estimate is incorrect and the PFD's recommendation relies purely on Staff speculation that the "projections are likely preliminary." A Commission decision may not lawfully be based upon speculation.[103]

f. Supervisory Control and Data Acquisition (SCADA)

Staff reasoned that "the Company is projecting $520,000 in capital expenditures for 2022, 2023 and 2024. Staff's position is that by virtue of the three projected amounts being identical, said projections are likely preliminary and the actual expenditure amounts could be different. Therefore, I averaged the actual spending from 2029 through 2022 . . . [and prorated the historic average

[103] *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).

amount to arrive at downward adjustments of] $134,904 for the 11 months ending 11/30/2023" and "$147,168 to the test year." (7T 4418-19). The PFD "finds that DTE has not established the basis for its cost estimate for this project and thus finds Staff's recommendation reasonable and concludes it should be adopted" (PFD, p 380).

The Company disagrees for two reasons. First, Staff's use of historic spending including 2019 is inappropriate because that year was an anomaly. In 2019, the Company mandated a freeze for any changes impacting its old EMS system (a SCADA component), thereby eliminating any development of this asset in preparation for implementation of the new system that would be launched as part of ADMS. The Company returned to full spending the following year once the cost for the new application began to be incurred. The Company did not replace this system on a regular basis and was transparent with the Commission about its investment plans in past cases. Second, the annual cost reflects the required labor by resource group. The similarity of the Company's annual costs simply reflects a planned level of spending with finite resource allocation to deliver the project. (5T 2056-57; Exhibit A-43, Schedule HH2).

g. ESRI Application Health

Staff reasoned that "the Company is projecting $440,000 in capital expenditures for 2023 and 2024. Staff's position is that, by virtue of the two projected amounts being identical, said projections are likely preliminary and the actual expenditure amounts could be different. Therefore, I averaged the actual spending from 2019 through 2022 . . . and prorated the historic average amounts to arrive at downward adjustments of $93,149 for the 11 months ending 11/30/2023" and "$101,617 to the test year" (Evans, 7T 4419). The PFD "finds that DTE has not established the basis for its cost estimate for this project and thus finds Staff's recommendation reasonable and concludes it should be adopted" (PFD, p 384).

The Company disagrees for two reasons. First, Staff's use of historic spending is inappropriate because investments in this asset were put on hold while supporting the overall ERSI Upgrade project. The Company was thereby able to maximize efficiencies and complete this support under its forecast in 2021. Second, the annual cost reflects the required labor by resource group. The similarity of the Company's annual costs simply reflects a planned level of spending with finite resource allocation to deliver the project (Sharma, 5T 2057-58; Exhibit A-43, Schedule HH3).

iii. DAAO's Proposed Disallowances.

a. Advanced Analytics (AA) Use Cases.

DTE Electric is investing $4.3 million in resources and technologies that will provide greater insight into customer segments, behaviors, and the customer experience. (5T 1725). DAAO witness Koeppel proposed a complete ($4.3 million) disallowance ($1.8 million for the bridge period; $2.5 million for the test year), noting one aspect of the Use Cases (reducing collection agency fees by $40,000 per year) and asserting that "these investments are not reasonable and prudent, as their impact is merely to expend ratepayer resources on more tools to navigate the complex morass of programs rather than to simplify and unify the programs." (6T 4015). The PFD states:

> This PFD finds that the costs for the Advanced Analytics AA use cases implementation project(s) are not adequately supported and the remaining costs not covered by Staff's Level 2 adjustment discussed above should be excluded from rate base. DTE's view that it has clearly delineated separate projects for its 2022 through 2024 spending is inconsistent with the information it provided in support of these projects, which reflect a jumble of projects and no detailed support for spending. [PFD, p 391.]

The Company disagrees with the PFD's reasoning and conclusion. The Company explained that DAAO (and by extension the PFD) is wrong for several reasons. First, Mr. Koeppel created

unnecessary confusion by comingling the 2023 and 2024 Use Cases in making his argument. The $40,000 reduction in third-party collection agency fees referenced by Mr. Koeppel pertains to only the 2023 use case in which the Company invested $0.4 million. The 2023 use case optimizes the Company's third-party collection processes through integration of the machine learning propensity-to-pay model with the Company's SAP CR&B system and collection processes. The model itself was developed and tested in a separate 2022 use case, in which the Company invested ~$700,000 of the $1.4 million spend in 2022. The 2022 use cases also included the development of a second machine learning model, described as NPS Phase 2 in the business case, to help the Company understand where in the collection process customers are experiencing the most friction and dissatisfaction, allowing the Company to identify and implement opportunities to reduce that friction and help customers. The Company maintains that the $4.3 million investment in the 2022-2024 use cases is a reasonable and prudent investment, and Mr. Koeppel does not suggest otherwise except by vague reference to unfounded suspicions. (5T 1725-26, 1798-99).

Mr. Koeppel's further reference to a "morass" of programs relates to the 2024 use case ($2.5 million), which is unrelated to the 2022 and 2023 use cases. The 2024 use case addresses inefficiencies in the energy assistance application process, which requires that customers who are struggling to pay their past-due balances contact the Company, or a third-party energy assistance agency, to determine their eligibility for various forms of state, federal and utility assistance programs. Mr. Koeppel suggests that the Company should simplify the "morass" of programs, but the Company does not control the various agencies or the administration of the programs. The 2024 Use Case addresses this issue by building a machine learning model that can predict a customer's energy assistance eligibility, so the Company can proactively reach out to vulnerable customers who qualify for energy assistance and reduce the complexity for them in applying for that

assistance. Thus, the 2024 investment does exactly what Mr. Koeppel suggests by simplifying the process and making sure that the right customers are referred to the right agency/program for assistance. (5T 1726-27, 1799-1800).

The Company also notes that Staff raised no concerns about the reasonableness and prudency of the Advanced Analytics Use Cases Project nor did the AG, other than the 20% blanket disallowance to all projects that Staff categorized as having a Level 2 estimate which included this project. It seems that the basis of Mr. Koeppel's objection to this project has more to do with his views on the current state of energy affordability and what type of IT investments would be helpful in advancing a unified affordability program. He also objects to recovery of this project alleging it is an example of the Company practicing the Profit Maximization Principle. The $40,000 reduction in collection agency fees touted by Mr. Koeppel can hardly be proof that the Company is acting in a manner consistent with this principle.

The PFD erroneously adopts DAAO's recommendations that the expenditures are not justified based on the reasons provided above and suggesting there are inconsistencies and omissions in the Company's exhibits supporting the Advanced Analytics Use Cases project. The PFD points out differences in the scope of the 2022 and 2024 use cases in the business cases vs. witness Hatsios testimony and costs shown in Exhibit A-12 Schedule B5.7.3, Line 14. As previously mentioned, the executive summaries of IT capital projects provided in Exhibit A-24, Schedule N1 are "point-in-time" documents reflecting what the scope and estimated costs are as of the date of developing the business case. During implementation, the 2022 project scope was reduced to two use cases, the NPS Phase 2 and Reactive Collection Cycle (or propensity-to-pay model), and hence, only two use cases were described in witness Hatsios testimony and accordingly, the cost of the 2022 investment was reduced from the estimated cost of $2.2 million to the projected

cost of $1.4 million in capital expense. (T5 1725-1726, Exhibit A-24 Schedule N1 page 288-289). Since the 2023-2025 Advanced Analytics Use Cases project is a single multi-year project with different use cases in each year (2023 – 2025), there is no separate breakdown of costs by use case. Given the rate case periods in the instant case, the $4.3 million of capital requested for recovery only pertains to the 2022-2024 project costs and does not include the estimated cost of approximately $3 million in capital expense for the 2025 use cases. (Exhibit A-24 Schedule N1 page 293).

The PFD also references other business cases that appear to provide similar benefits as the 2024 use case related to energy assistance eligibility such as the Contact Center Enablement Project on page 342 of Exhibit A-24 Schedule N1.

> DTE projects spending of approximately $1 million to both increase call handling efficiencies and "support our low income customers in obtaining as much energy assistance as possible to reduce their energy costs and avoid the possibility of disconnection due to non-payment." [PFD, p 395.]

The referenced business case standardizes the screens in our SAP Customer System that Contact Center customer representatives (CRs) would use to more efficiently handle customer calls related to the collection transaction, including providing energy assistance information to customers. (5T 1669). While the CR would be able to use the 2024 use case machine learning model output once it is deployed to review eligibility and discuss energy assistance options with the customer, these are two distinctly different projects.

The PFD also questions the methodology mentioned in the business case for measuring the expected value of the 2024 use case for energy assistance eligibility. The approach called A/B Testing is a commonly used statistical method for evaluating project benefit and would include setting up a test and a control group of customers. Measurement would be isolated from and

controlled for the benefits provided by other IT projects or changes in collection processes or policies to exclude the effects of these other projects or changes. (PFD, p 396). The apparent discrepancies highlighted by the PFD and as discussed above do not provide a basis for rendering the $4.3 million investment in this project an unreasonable and imprudent capital expense.

The PFD (at p 397) also notes a concern about an alleged potential double recovery through the Company selling uncollectible accounts to third parties for purposes of collection. To the contrary, when the debt is sold, the proceeds reduce historical net write-offs that are used to set the bad debt expense that the Company is requesting to recover in rates, which eliminates any risk of double recovery.[104] The Company also has a responsibility, on behalf of its ratepayers, to attempt to recover uncollectibles through available collection processes including debt sales. (Griffie, 4T 2107-2108).

b. Self Service IT.

Mr. Koeppel further indicated that $51.3 million of proposed capital expenditures on self-service IT would produce only "customer savings of $5.4 million." (6T 4018). The Company responded by explaining that Mr. Koeppel apparently misinterpreted a net present value (NPV) analysis. These investments create net revenue requirement savings of approximately $4 million for customers starting in 2027, which grows to sustained savings of approximately $14 million by 2035 for a total of approximately $48 million in net revenue requirement savings, undiscounted. Discounting these net cash flows back into today's dollars yields a negative $5.4 million, indicating

[104] Staff's Initial Brief, pp 151-53, reflects that "Staff agrees" that there is no potential for double recovery in rates associated with a debt sale; however, Staff goes on to suggest that there is a double recovery because the Company recovers uncollectible expense (reduced by proceeds from sales of accounts) and the party that buys the accounts might recover something from the non-paying customers. It is not clear to the Company how Staff's assertion that different amounts recovered by different parties would be a double recovery.

that the investments provide savings to customers, and supporting the reasonableness and prudence of the investments. (5T 1619-23, 1806; Exhibit A-24, Schedule N6, page 1, lines 22 and 23).

The PFD agreed with Mr. Koeppel finding that the project's benefit cost analysis results were not justified because the Company had not established the basis for its projected call volume decreases. (PFD, 404)

The Company disagrees. In addition to the discussion above, the PFD's suggestion that the Company should be required to "guarantee" future savings neglects that the future is inherently uncertain, and is contrary to the preponderance of evidence standard (which the PFD at p 29 correctly recognizes applies in this proceeding). Nevertheless, there are several pieces of evidence that support the Company's commitment to reducing Contact Center call volume. In Exhibit A-24 Schedule N5 on page 1, the Company summarizes the 2021-2024 Net Call Reductions and associated Net O&M Savings and 2023-2027 Net Call Reductions and associated Net O&M Savings from investments in the Reduced Call Volume Projects. These projected call volume reductions are based on realized reductions from the Company's investment in digital self-service capabilities starting in 2013 through 2022, which enabled a net reduction of 1.87 million calls over a 10-year period, and projected reductions in calls as more transactions such as for collections which generated approximately 1 million calls in 2022, and sub-transactions are added. (5T 1611-1613).

Also, on page 1 of Exhibit A-24 Schedule N5, the Company provided the Digital Engagement Rate (DER) by transaction in 2022 and the projected increases in DER for each transaction by 2027. DER is one of two ways the Company measures customers' interests in, and adoption of, self-service channels to complete their transactions with DTE, the other metric is Self-Service Rate. The growth in the Self-Service Rate since 2016 and DER since 2020 substantiates the decrease in live calls. (5T 1613-1615). Witness Hatsios describes in great detail the self-service

capabilities that have been, and will be, enabled for each of the five key customer transactions (MIMO, Outage, Collection, Billing and Payment) in 2021 through 2024 that will result in increasing levels of DER by 2026 or 2027 and correspondingly, reduced call volume to the Contact Center, providing customers the benefit of lower Contact Center O&M costs. Higher DER and projected call volume reductions are further referenced and provided for each transaction in Exhibit A-24 Schedule N5 and modeled using NPV analysis in Exhibit A-24 Schedule N6. (5T p 1604-1665). Finally, the Company has already passed on the O&M savings from the projected call volume reductions to customers for the period 2021-2024, removing 100% of the risk to customers realizing the benefit, shown on page 1 Line 16 and page 2 Line 23 of Exhibit A-24 Schedule N5, modeled in the NPV model in Exhibit A-24 Schedule N6 Line 27, and the adjustment made to reduce O&M costs from the Digital Investments in Exhibit A-13 Schedule C5.7 Line 5 and footnote 3. Together, reduced call volume based on realized and projected reductions, higher projected DER, and the downward adjustment to O&M expenses from the digital investments should more than adequately support the reasonableness and prudence of the self-service digital investments.

It is also worth noting that both Staff and the AG made no comments regarding the reasonableness and prudence of the Self-Service projects in their testimony or briefs despite having concerns about these projects and the lack of a cost benefit analysis provided in prior rate cases.

The PFD arbitrarily adds capital expenditures from an unrelated program, such as the Advanced Analytics Use Cases, without considering that project's specific scope, and makes claims that such projects offset the benefits provided to customers. As described in witness Hatsios testimony, projects that are included in the $51.3 million investment are those that provide the technical capability of enabling customers to complete their transaction in a digital channel (e.g.,

Web, Mobile, IVR, VA, or Chat) versus utilizing the call channel by calling a CR to complete their transaction.

14. Summary of Rate Base - Net Plant.

The Company maintains that based on the acceptance of the adjustments identified in its Initial Brief and Reply Brief, DTE Electric supports a $21.283 billion net balance as shown on Attachment A, page 2.

B. Working Capital

1. Energy Insurance Services.

DTE Electric disagreed with AG witness Coppola's proposal to remove $38.9 million from working capital for a special investment fund with Energy Insurance Services (EIS), and suggested instead to include a projection for gains and losses on the investment in future rate cases (Uzenski, 5T 1565, 1574-75). The PFD inaccurately states: "Given that DTE and the Attorney General are in agreement as to how this issue should be addressed in this case, with no other party objecting, this PFD concludes that the agreed-upon ratemaking treatment should be adopted in this case" (PFD, p 410).

Instead, a disagreement remains. The problem arises from the AG misstating Witness Uzenski's rebuttal testimony (AG Initial Brief, p 93: "The AG agrees with this treatment of removing the EIS asset balance from the working capital calculation and including the five-year average of gains and losses in operating income").Witness Uzenski specifically stated, "The Company is amenable to including, in future rate cases, a forecast of the income impact from the fund in projected operating income based on a five-year average in lieu of removing the asset from

rate base" (Uzenski, 5T 1574-75, emphasis added). The Company did not, and does not agree to remove the EIS asset balance from working capital.

Witness Uzenski further explained that the Company's investment for funding insurance supports utility operations and is properly included in rate base. The investment fund is used to record DTE's interest in EIS, which is a Segregated Captive Cell Insurance (captive insurance) company, meaning that assets are held for insurance purposes that are for DTE only. The asset is marked to market quarterly, which results in the recognition of gains and losses. The gains and losses on the investment fund have been excluded from rates because they are related to changes in the market value of the fund and cannot be forecasted (Exhibit A-36, Schedule AA3 shows gains and losses over the last five years). Instead of removing the asset from rate base, the Company proposes to include a projection for gains and losses on the investment in future rate cases. This would be consistent with how gains and losses on DTE Gas' Grantor Trust fund are treated for ratemaking (Uzenski, 5T 1565, 1574-75). Therefore, the Commission should issue a decision in accordance with the discussion above.

2. Regulatory Asset – Deferred Incentive Compensation.

AG witness Coppola proposed to remove the $5.6 million regulatory asset for deferred incentive compensation from working capital, arguing that it is premature to create a regulatory asset (6T 3765). The PFD "finds Mr. Coppola's testimony persuasive that in allowing DTE the possibility of recovering additional EICP associated with operational metrics, the Commission in Case No. U-20836 did not intend to require ratepayers to provide DTE with a return on that potentially-deferred amount of incentive compensation, prior to a determination whether the operational targets for a given year were actually met" (PFD, p 412).

The Company disagrees because accrual accounting allows the Company to record a regulatory asset when recovery is probable. Although the Company is not requesting recovery of the deferred costs in amortization expense in the instant case, it is appropriate to accrue the regulatory asset on the balance sheet because the Commission approved such treatment in Case No. U-20836 (Uzenski, 5T 1565, 1575-76).

3. Summary of Working Capital.

The Company maintains that based on the acceptance of Staff's reduction to working capital of $7.3 million for non-utility accounts receivable and $1.7 million for the thirteen-month average, DTE Electric supports a $1.251 billion working capital balance as shown on Attachment A, page 2.

The Company's other exceptions affecting the PFD's working capital recommendations [105] are noted in the context of topics from which they arise, where they are best understood in context.

VII. RATE OF RETURN

The PFD recommends a weighted, after-tax overall rate of return of 5.52% (PFD, pp 487, 858 and Appendix D). DTE Electric takes exception regarding this and the PFD's 9.8% return on equity (ROE). (PFD, pp 482). DTE Electric requests a weighted, after-tax 5.70% overall rate of return (Vangilder, 5T 2592; Exhibit A-14, Schedule D1, line 10, column (g)), which the Commission should adopt for the reasons discussed below.

[105] PERC -Nuclear Uprate Deferred Costs, Capitalized Software obligations, Regulatory Asset – emerging technology fund and Regulatory Asset – DFEP.

A. Return on Common Equity

The PFD recommends that the Commission lower DTE Electric's ROE from 9.9% to 9.8% (PFD, pp 482-87). The Commission should instead adopt DTE Electric witness Dr. Villadsen's recommendation that a just and reasonable ROE for DTE Electric's common equity capital is 10.25%. This is the midpoint of a reasonable range, and is conservative because DTE Electric has greater-than-average risk. (Villadsen, 5T 2954-55, 2995, 2999, 3044).

The PFD "finds Mr. Coppola's and Mr. Ufolla's testimony persuasive that DTE's return on equity should be set at 9.8%" (PFD, p 482). The Company disagrees, first noting that Staff, the AG, and ABATE were the only three parties that offered any substantive analysis to support their recommendations.[106] The most noteworthy thing about Staff, the AG, and ABATE's recommendations is that they all recommended a *higher* (by 0.15% to 0.3%) ROE than they did in Case No. U-20836, where Staff recommended 9.6% (Ufolla, Case No. U-20836, 8T 5085-5100-5101), the AG recommended 9.5% (Coppola, Case No. U-20836, 8T 4818, 4846), and ABATE recommended 9.4% (Walters, Case No. U-20836, 8T 3046-3047). There, the ALJ "recommend[ed] that the Commission should keep DTE's authorized ROE at 9.90%" (U-20836 PFD, p 456). The Commission agreed, noting the "uncertainty currently impacting financial markets" (November 18, 2022 Order in Case No. U-20836, p 242).

Thus, Staff, the AG, and ABATE all acknowledged that times have changed since the Commission set DTE Electric's ROE at 9.9%, and that the consistently-used forms of ROE modeling indicate a *higher* cost of equity. Nonetheless, the PFD recommends lowering it, which is

[106] ABATE recommended 9.55% (Walters, 4T 1154-55, 1207). Other witnesses suggested that the Company's ROE should either not increase, or be reduced, but did not support their recommendations with a ROE analysis using financial market data. Thus, their unfounded and irrelevant assertions cannot support a decision and merit no serious consideration. (Villadsen, 5T 3046, 3048, 3053-55, 3087-90).

not reasonable in the current environment of high inflation and rising interest rates. Dr. Villadsen explained in part:

> The ROEs recommended by [Staff, the AG, and ABATE] are too low as they all recommend a decrease in DTE Electric's allowed ROE, while indications are that the cost of equity has increased since DTE Electric's cost of equity was last assessed. Since the ALJ's Proposed Decision in September 2022, interest rates have increased, the Federal Reserve has raised the Federal Funds rate six times for an increase of 275 basis points. At the same time, the average allowed ROE for integrated electric utilities were higher in Q4 2022 and Q1 2023 than during the time of last rate case by approximately 35-50 basis points. . . . Consequently, there are strong indications that the cost of equity has increased rather than declined. [Villadsen, 5T 3049-50. Footnotes omitted. See also, 5T 3047, 3087-88.] [107]

The Commission has considered such matters previously and should continue to do so. In DTE Electric's next-to-last general rate case, the Commission set DTE Electric's currently authorized ROE at 9.9%, explaining in part:

> At this time, the Commission finds that an ROE of 9.90%, which is at the lower end of DTE Electric's proffered range of 9.75% to 10.75%, most appropriately compensates DTE Electric for the regional economic and company-specific aspects of risk, while maintaining its ability to attract capital, and ensuring the continued vitality of the company. . . .
>
> The Commission 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. [May 8, 2020 Order in Case No. U-20561, pp 176-177.] [108]

Dr. Villadsen further explained, as indicated in part above, that interest rates have increased substantially since the record was made in Case No. U-20836, and the estimated cost of equity is

[107] Dr. Villadsen also noted that Staff, the AG, and ABATE made various modeling choices that downward-biased their results (summarized at Villadsen, 5T 3052-53), some of which are discussed below where they are best understood in context.

[108] The Commission also recently approved a settlement agreement including a 9.9% ROE and 50.75% common equity ratio for Consumers Energy (July 7, 2022 Order Approving Settlement Agreement in Case No. U-21148, p 2).

now higher than what is reflected in the data that the Commission reviewed in Case No. U-20836 (Villadsen, 5T 2955).

Dr. Villadsen also explained that, in response to persistent high inflation, the Federal Reserve had [so far at that time] increased rates seven times (425 basis points) since March 2022. Regardless, the Consumer Price Index remains high. Tightening monetary policy along with increasing economic and financial risks has caused interest rates to rise. Historically, interest rates and the cost of equity have moved in the same direction (Villadsen, 5T 2964-69). She summarized these recent developments and why they are important here:

> Overall, the state of U.S. capital markets indicates that we are experiencing the highest level of inflation since the stagflation of the late 1970s to early 1980s. We have entered into a period of rising interest rates, which are expected to continue to rise to combat increasing inflation, and we are experiencing substantial global uncertainty in Europe due to the war in Ukraine. The recent monetary tightening taken by the Federal Reserve tightened monetary policy and increased interest rates.
>
> Taken together, these facts indicate that an increase in the allowed ROE relative to DTE Electric's last rate case to 10.25% is warranted to compensate DTE Electric's investors for the systemic risk that currently is incurred and the risk to which the investors are expected to be exposed [while] the allowed ROE is in place. [Villadsen, 5T 2977.]

The AG's Initial Brief, p 91, acknowledged that "the current state of the economy and financial markets has increased business risk." AG witness Coppola also acknowledged that "in late 2021 and early 2022, inflation has become a concern. To combat this threat, the Federal reserve has increased short term interest rates" (6T 3750), and "the current state of the economy and financial markets has increased business risk" (6T 3758). Recognizing these facts, AG Witness Coppola recommended a higher ROE than in DTE Electric's prior case.

This is also a particularly inopportune time to weaken the Company's credit metrics due to the Company's need for capital spending, as discussed above. The Commission has historically recognized the connection between ROEs and capital spending. (January 31, 2017 Order in Case

No. U-18014, pp 65-66; December 11, 2015 Order in Case No. U-17767, pp 54-55). The ALJ suggests that she did not find this persuasive, indicating that the Company has made this argument previously and "it is not reasonable to view the company's rate of capital investment as moderating anytime soon" (PFD, p 486). The PFD's reasoning does not support her decision, but instead confirms that the Company's position is well founded and reasonable.

The PFD's findings and conclusions discussion (PFD, 482-87) is also incomplete in adopting certain criticisms of Dr. Villadsen's presentation, as suggested by other parties, without analyzing those parties' presentations or evaluating them in complete context. Therefore, DTE Electric presents the following additional discussion of the evidentiary record.

Dr. Villadsen supported her recommendation with a sample of 26 regulated electric utility companies. She also confirmed her results using a sample of seven natural gas local distribution companies (LDCs). The proxy groups are similar to DTE Electric because they are rate regulated by state utility commissions, serve customers through a network of assets, and are capital intensive (Villadsen, 5T 2962, 2979-84). Criticisms of the gas sample should be rejected because Dr. Villadsen based her recommendation solely on the Electric Utility Sample, while the Natural Gas Sample simply verified the results (Villadsen, 5T 3057).

Dr. Villadsen estimated the ROE for each company in her sample using two versions of both the Capital Asset Pricing Model (CAPM),[109] and Discounted Cash Flow (DCF) approaches, as well as a risk premium model. She also considered differences in financial risk inherent in each company's capital structure (the higher the debt-to-equity ratio, the higher the financial risk, and the higher the cost of equity) using (1) the overall cost of capital approach, and (2) the Hamada

[109] The CAPM is a risk positioning approach. Dr. Villadsen also used the Empirical CAPM (ECAPM) (Villadsen, 5T 2962, 2985).

approach. In recognition of the Commission's past decision to not rely on the overall cost of capital approach, however, her CAPM / ECAPM recommended range is based on the Hamada approach. This approach cannot be applied to the DCF model (Villadsen, 5T 2959-63, 2984-85).

Her rebuttal testimony further discussed well-established financial principles, and responded to criticisms and apparent misunderstandings by Staff, the AG, and ABATE regarding the impact of financial leverage on the cost of equity. By failing to account for fundamental financial principles, the Staff, AG, and ABATE's ROE estimates are downward biased and unreasonable (Villadsen, 5T 3070-82).

1. CAPM and ECAPM Estimates.

Dr. Villadsen developed ROE estimates based on the CAPM and an empirical approximation to the CAPM (ECAPM). The CAPM is based on the idea that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk using (a) a risk-free rate, (b) beta,[110] and (c) a market risk premium (MRP). (Villadsen, 5T 2985).

Dr. Villadsen further explained that empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta. Low-beta stocks tend to have higher risk premiums than predicted by the CAPM, whereas high-beta stocks tend to have lower risk premiums than predicted by the CAPM. Dr. Villadsen adjusted by using the ECAPM, which uses these empirical findings to produce results that more closely match the results of empirical tests (Villadsen, 5T 2986). Criticisms of the ECAPM are misplaced, but the ECAPM has little if any

[110] Beta is a measure of the risks that cannot be eliminated by diversification. It measures the "systematic" risk of a stock – the extent to which the stock's value fluctuates more or less than the market fluctuates (Villadsen, 5T 2985).

effect on Dr. Villadsen's estimated ROE, so she relegated her discussion to an appendix (Villadsen, 5T 3057).

As a proxy for the risk-free interest rate, Dr. Villadsen used the average yield on the 10-year U.S. Treasury bond forecasted by *Blue Chip Economic Indicators* to be in effect for 2023 - 2024, and adjusted it upward by 50 bps, which is her estimate of the representative maturity premium for the 20-year over the 10-year Treasury bond, for a risk-free rate of 4.05%. Her Scenario 1 combines the 4.05% risk-free rate with the 7.46% historical average MRP. Her Scenario II combines the 4.05% risk-free rate with Bloomberg's forecasted MRP (over the 20-year Treasury bond yield) of 5.05% (rounded to 5.0%). She did not make a yield spread adjustment, as she has done in the past (Villadsen, 5T 2987-88).

The Electric Utility Sample's results are consistent with a cost-of-equity range of 9.0% to 11.5% (ignoring the financial risk adjustment that the Commission criticized in the past). Rounding to the nearest ¼ percent (which is Dr. Villadsen's practice), the CAPM (and ECAPM, which is virtually no different) indicates a ROE range of 9.0% to 11.5% for the Electric Utility Sample before any DTE Electric risks are considered. The Natural Gas Sample has comparable to slightly lower results (Villadsen, 5T 2989).

Staff computed an ROE of 10.34% using an historical CAPM, and 13.63% using a projected CAPM, but "heavily discounted" the projected CAPM (Ufolla, 7T 4713, 4715-16). Dr. Villadsen agreed with the use of multiple CAPM scenarios, but disagreed with Staff's decision to essentially ignore half of the results, as this significantly affected the outcome of Staff's ROE analysis. For example, the average of the CAPM results is 11.99%, but Staff's upper bound on the ROE is 10.3%, which is the historical CAPM result. If the projected CAPM result is included, the average of the DCF, CAPM, and risk premium models is 10.4%. Thus, Staff's own modeling supports a 10.4%

ROE average, which is significantly above Staff's 9.8% ROE recommendation, and more in line with the Company's 10.25% request (Villadsen, 5T 3052, 2064).

AG witness Coppola's CAPM model indicates a cost of equity of 10.01% ignoring financial leverage, and 10.96% when financial leverage is considered, which supports the Company's 10.25% request (Villadsen, 5T 3064).

Dr. Villadsen disagreed with ABATE witness Walters' beta analysis, emphasizing that it is imperative that betas reflect the best current estimate of systemic risk. Mr. Walters' use of the historic average of betas since 2014 lacks relevance and downward biases his CAPM results by 0.4% to 1.0%. He also neglected to account for DTE Electric's capital structure, and relied upon a risk-free rate that was too low (Villadsen, 5T 3065).

2. DCF Estimates.

Dr. Villadsen explained that the DCF model assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The single-stage DCF model assumes that the stream of future dividends will grow at a constant rate into perpetuity. The multi-stage DCF model accommodates different dividend growth rates at different points in time (Villadsen, 5T 2990-91).

Dr. Villadsen calculated both the single-stage and multi-stage DCF using growth rates from *Value Line* and *IBES*, as well as GDP forecasts from *Blue Chip Economic Indicators* for the multi-stage DCF. The corresponding ROE estimates range from 8.9% to 10.7% for the Electric Utility Sample, and 8.7% to 11.0% for the Natural Gas Sample. Dr. Villadsen viewed the multi-stage results (8.9% and 8.7%) as unrepresentative, however, because they are out of line with other results, and might fail to capture the substantial growth needed in the electric sector to accomplish the transition to a low-carbon economy. Therefore, she considered the upper half of the range

determined by the estimation results reasonable. That is a reasonable range of 9.8% to 10.7%, with a midpoint of 10.25%, before any DTE Electric risks are considered (Villadsen, 5T 2992).

Dr. Villadsen's rebuttal responded to other witnesses' criticisms and their implementation of DCF models (Villadsen, 5T 3060-63). The deficiencies in Staff's and the AG's modeling do not make much difference in the results, but ABATE's sustainable growth method is not properly implemented for at least two reasons. First, it relies on only one source for its growth rates. Second, an input to the model, the expected return on equity, averages 11.09%, but Mr. Walters calculated an ROE of 8.89%. This is inconsistent and unreasonable. As such, the model merits no consideration (Villadsen, 5T 3061).

3. Risk Premium Estimate.

In the risk premium model, the cost of equity capital for utilities is estimated based on the historical relationship between allowed ROEs in utility rate cases and the risk-free rate of interest at the time the ROEs were granted. The risk premium model produces an estimated 10.4% ROE for electric utilities. This is consistent with the estimates from the CAPM and the DCF model for the Electric Utility Sample (Villadsen, 5T 2993-94). Dr. Villadsen's rebuttal testimony responded to other witnesses' criticisms and the implementation of their models (Villadsen, 5T 3067-69).

The PFD found Dr. Villadsen's risk premium model to not be compelling, vaguely referencing AG witness Coppola (PFD, p 484). However, Mr. Coppola misunderstood the model, suggesting, for example, that it was based on "the premise that treasury bond yields are the primary driver in ROE decisions by regulators" (6T 3750). Instead, Dr. Villadsen's statistical model reflects an empirical fact, which is also consistent with the observation that investors require a higher risk premium to hold equities over government bonds as bond yields decline (Villadsen, 5T 2993).

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

As indicated above, in DTE Electric's last rate case, the PFD "recommend[ed] that the Commission should keep DTE's authorized ROE at 9.90%" (U-20836 PFD, p 456). The Commission agreed, further explaining why the lower ROEs suggested by the Staff, AG, and ABATE should not be adopted:

> [A]dditional concerns must be given weight in determining the most reasonable and prudent ROE. The ALJ appropriately relied on the Commission's [March 29, 2018 Order in Case No. U-18322] wherein the Commission held "it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions." March 29 order, p. 44. In addition, while declining to take official notice of recent increases in interest rates by the Federal Reserve as recommended by DTE Electric, the Commission notes that the financial system is experiencing some turbulence resulting from inflation, supply chain disruptions, and other factors. As noted in the [May 8, 2020 Order in Case No. U-20561]:
>
> > The Commission 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.
>
> May 8 order, p. 177.
>
> Given the uncertainty currently impacting financial markets, the Commission finds that the most prudent course of action is to adopt the ALJ's well-reasoned findings and maintain both the current ROE and capital structure. The Commission may revisit this determination in future cases as it gains greater insight into the issues currently affecting the financial markets and longer-term macro-economic trends. [Case No. U-20836 Order dated November 18, 2022, pp. 242-43. Footnote omitted.]

Before setting DTE Electric's ROE at 9.9% in Case No. U-20561, the Commission previously set DTE Electric's ROE at 10.0%, stating that it "agrees with DTE Electric that factors such as volatility and uncertainty are currently particularly significant, and movements are more extreme in comparison to more stable historical periods" (Case No. U-18255 Order dated April 18, 2018, p. 32). The Commission maintained that ROE in DTE Electric's next general rate case, stating that it "was not persuaded that economic conditions have changed sufficiently, if at all, to warrant

an increase in DTE Electric's ROE . . . [but it] will continue to monitor a variety of market factors in future applications to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE" (Case No. U-20162 Order dated May 2, 2019, pp. 67-68).

In Case No. U-20940 (DTE Gas's most recent general rate case), the Commission maintained the ROE at 9.9%, despite the Staff and AG proposing, and the ALJ's recommending, lowering of DTE Gas's ROE to 9.5%. The Commission explained in part that it "observes that an ROE of 9.90% falls within DTE Gas's recommended range of 9.25-10.25% . . . [and] there may be continued uncertainty in the capital markets that may affect the cost of capital" (December 9, 2021 Order in Case No. U-20940, p 92). See also the December 17, 2020 Order in Case No. U-20697, pp 165-166, where the Commission stated that it "will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE").

The Commission has also emphasized that in the present regulatory environment where rate cases are more common, proposals to radically reduce a utility's ROE are neither realistic nor helpful to the Commission (Case No. U-18999 Order dated September 13, 2018, p. 52). In addition to the discussion above regarding Case No. U-20836, the Commission has repeated its recent request for parties "to consider the degree of financial adjustment they are requesting the Commission to undertake in one proceeding, because it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions." *Id.*, quoting Case No. U-18322 Order dated March 29, 2018, p. 44. Here, the underlying economic conditions support an increase in DTE Electric's ROE, as Dr. Villadsen recommended, rather than the PFD's recommended decrease.

In the current environment of market uncertainty, DTE Electric's lack of a revenue decoupling mechanism or lost revenue adjustment mechanism places it at increased risk of under-recovering its cost of service relative to some companies in Dr. Villadsen's sample that benefit from such mechanisms. Moreover, and in addition to ongoing uncertainty in the capital markets discussed above, DTE Electric faces increased risk of under-recovery because its service territory includes the greater Detroit area, which continues to be economically challenged. This risk has also recently increased because during times of high inflation, the impact on communities with lower income is larger. DTE Electric also has an asymmetrical risk (downside risk with no corresponding upside) due to the responsibilities of owning and safely operating a nuclear power plant. Therefore, DTE Electric has a higher-than-average business risk relative to companies in Dr. Villadsen's sample (Villadsen, 5T 2955, 2995-98).

The PFD suggests that Dr. Villadsen presented a "one-sided view of the risks facing DTE relative to the proxy companies" that it characterized as "deeply troubling" (PFD, p 484). To the contrary, Dr. Villadsen essentially maintained the position that she has presented in past cases. The PFD's suggestion that the Company's risk has somehow decreased in this last year, following the Order in Case No. U-20836, is not supported by the record and is not consistent with all relevant factors.

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

The Commission should increase DTE Electric's ROE to 10.25% because, primarily due to increased interest rates, the current cost of equity is higher than it was when the Commission set DTE Electric's ROE at 9.9% in Case No. U-20561 and maintained it in Case No. U-20836. The average of the low and high estimates from Dr. Villadsen's DCF, CAPM and Risk Premium models

results in a range of 9.7% to 10.8%, the midpoint of which is 10.25%. This is a conservative estimate for DTE Electric's ROE because DTE Electric has higher-than-average risk compared to the sample companies, so it would be reasonable to place DTE Electric in the upper half of the estimates (Villadsen, 5T 2999).

The PFD's recommendation to lower DTE Electric's ROE is also inappropriate in today's financial environment of high inflation, rising interest rates, and continuing business risk. ROEs have increased in recent months, as have indicators of the cost of equity (Villadsen, 5T 3046-47, 3049-50, 3087-88). It is also important to maintain DTE Electric'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 PFD's recommendation to reduce DTE Electric's ROE to 9.8% is impropriate. The Commission should instead increase DTE Electric's ROE to 10.25%.

VIII. DTE ELECTRIC'S ADJUSTED NET OPERATING INCOME SHOULD BE ADOPTED

DTE Electric projected its Total Electric Adjusted Net Operating Income (NOI) to be approximately $861.1 million (as revised in DTE Electric's briefs and shown on Exceptions Attachment A, page 3). The PFD recommends approximately $1 billion (PFD, p 569 and Appendix C). DTE Electric takes exception to this and other matters as discussed below.

A. Sales Forecast

The PFD does not discuss the Company's sales forecast generally, presumably because there is no dispute. For completeness, the Company notes that its Initial Brief, pp 171-75, explained

and supported the Company's projected future sales, and the rigorous and accurate forecasting methodology that the Company uses to determine those sales. Staff's Initial Brief, pp 75-76, agrees. No party presented contrary or alternative testimony. Therefore, the Commission should adopt Mr. Leuker's well-supported and undisputed sales projections.

The only dispute concerned the Other (street lighting) forecast provided by Mr. Bellini (5T 2621-22). MAUI witness Bunch suggested that the Commission "order DTE to reduce the electric sales forecast for streetlights for the projected test year by 4,508,803 kWh, or approximately 3.25%, and to reduce the revenue requirement for streetlights accordingly" (4T 940). The PFD "finds that the lighting sales forecast should be adjusted to reflect the outage data as MAUI argues" (PFD, p 494).

The Company disagrees because not all outages are the result of failed Company equipment, and when the Company is impeded from making a repair, these additional 1,931 "follow-up" events in 2022, added over 2.5 days (over 50%) to the Company's restoration time for a total of 7.24 days (Exhibit A-40, Schedule EE3, line 9). Also, the adjustment would theoretically account for outages for which credits are paid (and Mr. Bunch suggests further credits), resulting in double compensation (in other words, a general situation where there would be no payment to the Company for electricity, plus the Company would make payments to some customers for electricity that was not paid for in the first place). MAUI should not be able to have it both ways by reducing the sales forecast as well as the proposed credits resulting in duplicative compensation. The most equitable solution continues to be the Company's current process of evaluating each customer-requested outage credit for reasonableness and issuing approved credits directly to the municipality. Therefore, the PFD's proposal to reduce the streetlighting sales forecast should be rejected (Bellini, 5T 2670-71).

IX. OPERATING AND MAINTENANCE (O&M) EXPENSES

DTE Electric projects total O&M of $1,293.2 million in the test period (as revised by DTE Electric's briefs and shown on Attachment A, page 3).

A. Energy Supply

The Company explained and supported its actual and forecast Energy Supply O&M expenses (See generally, DTE Electric's Initial Brief, pp 178-80). The Company's O&M projections include a normalization adjustment for the North Area periodic outage spend (Exhibit A-13, Schedule C5.1, page 1, note 6). Staff recommended that the Company's $11.5 million adjustment be reduced to $2.6 million. The PFD reflects the issue, but does not recommend a decision (PFD, pp 498-500), although Staff's adjustment is indicated at PFD Appendix C, line 6. The Company takes exception to the apparently recommended (but unexplained, contrary to MCL 24.281(2)) disallowance and maintains its position.

More specifically, Staff recommended that the Company's $11.5 million adjustment be reduced to $2.6 million, stating "Staff found that DTE Electric spent less than average in 2021 at its Belle River and Greenwood plants, but it spent more than average at its Monroe plant. When Staff included the Monroe plant in the 2017 to 2020 average, the periodic average was reduced to $2,599,978 after inflation as shown on Exhibit S-21.6 page 6" (Kindschy, 7T 4516-17).

The Company disagrees with Staff's inclusion of Monroe (a South Area plant) in its calculations. The Company did not include Monroe because a major Monroe periodic outage was included in both the historic and projected test years. Thus, the Company's adjustment just concerns North Area plants. Staff's inclusion of Monroe in its calculations is particularly inappropriate

because Monroe did not have a periodic outage in 2020 due to COVID-19 concerns.[111] Calculating a four-year average with what is effectively three years of data mathematically results in a lower number, but its methodology is unsound. By neglecting the COVID-19 anomaly, Staff's inclusion of 2020 Monroe periodic outage values in its 2017-2020 calculations effectively assumes that a pandemic will occur every four years and require Monroe periodic outages to be deferred by a year. The Company further notes that Staff's response (reflected at PFD, p 500) focuses on the use of 2020 data for Monroe, and misses the Company's broader point that Monroe (a South Area plant) should not be included in calculations concerning the North Area plants, particularly since Monroe did not have a periodic outage in 2020 due to COVID-19 concerns. Staff also included 2018 periodic outage expenses for Belle River and Greenwood. The Company's calculation appropriately did not because Belle River did not have a periodic outage in 2018, and Greenwood had only a very small, planned outage. There typically is one major periodic outage per year at the North Area plants. Therefore, 2018 actual O&M expenses would be an improper representation for yearly periodic outage spend. The Company's future projections further support the Company's requested recovery. For all of these reasons, Staff's proposed periodic O&M adjustment (as apparently adopted without explanation by the PFD) should be rejected (Morren, 5T 2425-27).

1. Nuclear Power

The Company explained and supported Fermi 2's O&M expenses, and Program Evaluation Review Committee (PERC) Regulatory Asset amortization, including its Extended Power Uprate (EPU) proposal (See generally, DTE Electric's Initial Brief, pp 180-82).

[111] Monroe is a 3,066 MW coal-fired power plant located in Monroe County. It is the fourth largest coal-fired power plant in the United States, and represents approximately 30% of the Company's generation energy mix.

In Case No. U-20836, AG Witness Coppola proposed that DTE Electric not start the EPU Study, and to remove the associated PERC O&M EPU expenditures. The Commission agreed (Case No. U-20836 Order dated November 18, 2022, p. 306). Witness Coppola has renewed his objection and again recommended that the Commission reject the Company's EPU proposal (6T 3769-3771). Mr. Davis explained that the requested capital expenditures for the EPU Study ($4.9 million in 2023 as shown at Exhibit A-13, Schedule C5.15, page 1, line 18) are to provide a detailed feasibility, scoping and estimating analysis, regarding the potential for Fermi 2 to support an EPU, which would potentially yield an additional 172 Mwe of carbon-free, resilient, baseload generation capacity. The only variable O&M cost associated with this additional 172 Mwe is the cost of nuclear fuel, which could result in significant PSCR savings for DTE Electric customers. The EPU Study would also provide the Company with an improved understanding of the operational considerations required to operate Fermi 2 at EPU conditions, and narrow the uncertainty of scope and expenditures associated with the work that would be required to complete an EPU, which is a reasonable and prudent approach (Davis, 5T 2495-97).

Moreover, the EPU Study's purpose of examining the feasibility of nuclear power generation is consistent with recently-enacted MCL 460.10hh (providing for the Commission to conduct a nuclear feasibility study) and the March 24, 2023 Order in Case No. U-21358 (reflecting the Commission's plan to comply with legislative directives).

The PFD agreed with the AG, stating:

> Just as in the previous case, i.e. Case No. U-20836, DTE did not rebut or address Mr. Coppola's analysis showing that an EPU—even at the low end of DTE's preliminary cost estimate—would be exceedingly uneconomical in terms of cost per MW when compared to the cost of capacity from other sources.
>
> The only circumstances that have changed since the last rate case are the passage of the IRA and MCL 460.10hh. However, Mr. Davis testified that there was still uncertainty regarding whether IRA tax credits would be available to defray the cost

> of any potential EPU; thus, that uncertainty cautions against undertaking the study because it is unclear whether or to what extent IRA tax credits could affect the economic feasibility of an uprate. Further, MCL 460.10hh directed the Commission to engage an outside consulting firm to conduct a feasibility study on various issues pertaining to nuclear generation. See MCL 460.10hh(1). That statutory provision does not directly support spending money on an EPU study when DTE already has reason to know that an uprate would be uneconomical. [PFD, p 568. See also, p 413.]

DTE Electric disagrees. In addition to the discussion above, Mr. Coppola did not perform an "analysis" as the PFD suggests. Instead, he just made a broad proposition based on what he acknowledged was a "very preliminary estimate [that] could change significantly depending on the upgrades needed to the plant and equipment" (6T 3770). The PFD further acknowledges that circumstances have changed, and the PFD's own reasoning that there is "uncertainty" regarding IRA tax credits undermines the PFD's unfounded presumption that an uprate would be uneconomical. DTE Electric (and the Commission) should not continue to be cut off from knowledge and options in the absence of the requested study. The EPU study is reasonable and prudent, so its cost should be approved.

2. Distribution

The Company revised its original ($349.0 million) projection to $344.4 million as shown on Exhibit A-13, Schedule C5.6 Revised (See generally, DTE Electric's Initial Brief, p 182-83).

i. Restoration O&M (Inflation).

MNSC witness Ozar proposed that the Commission "reject DTE's inflation adjustment, in the amount of $17,830,000" associated with restoration O&M expenses, asserting that "[i]t is unjustified for DTE to include an adjustment for inflation and not an offsetting adjustment for distribution system reliability productivity, while in the same proceeding request hundreds of

millions of dollars in incremental surge trimming and strategic investments that the Company claims will improve reliability (and by extension reduce Restoration O&M).” (Ozar, 6T 3573).

The Company disagreed because an inflation adjustment for O&M expenses is a well-established practice (See, for example, November 18, 2022 Order in Case No. U-20836, pp 256-58). The Company also already proposed a $6.3 million reduction for tree trim surge investment avoided costs (discussed further below), and the Commission previously found a similar offset to be sufficient (November 18, 2022 Order in Case No. U-20836, pp 262-63). Therefore, the proposed reduction should be rejected. (Hartwick, 5T 2162-63).

The PFD presents a wide-ranging discussion to which the Company takes general exception for lack of merit and relevance (PFD, pp 507-10). The only part relating to a specific disallowance in this category is the following:

> Consistent with this PFD’s recommendation that normalization adjustments should not be made to historical capital expenses to avoid masking productivity increases, this PFD similarly recommends that the historical normalization adjustments to 2017 through 2020 restoration O&M expense levels should be rejected. Those normalization adjustments are shown on lines 3 and 11 of Schedule C5.6 page 2 and add $3.1 million and $3.4 million respectively to the 2021 historical test year values. The impact of this adjustment excludes $6.5 million from the historical test year, which carried through to the projected test year using DTE’s inflation values [which the PFD generally recommended at PFD, p 497] results in a total O&M expense reduction in this category of $7.1 million. [PFD, p 509.]

The Company disagrees, as indicated above. The Company further notes that the PFD shifts this O&M discussion to the context of emergent capital expenditures and suggests that the Company “provided no specific analysis” in response to the Commission’s request for further evidence in this case on the effect of the Company’s capital investments on productivity benefits (PFD, p 508).

The Commission relevantly stated: “The Commission is also interested in, and finds appropriate, the ALJ’s recommendation that DTE Electric be required to present further evidence in its next rate general case on the effect of the company’s capital investments over recent years on

productivity benefits and any continued need for inflationary adjustments to historical data in this cost category for emergent replacements in the future." (November 18, 2022 Order in Case No. U-20836, p 63). The Company maintains that it properly responded to the Commission, and there remains no sound basis for the PFD's position (See also, Exhibit AG-1.78, p 2, and the Company's previous discussion at section IV. A. 10. ii, Emergent Replacement – Storm and Non-Storm).

ii. Tree Trimming.

The Company's explained and supported its proposals for base O&M and surge funding (See generally, DTE Electric's Initial Brief, pp 183-91). AG witness Coppola recommended that the Commission "remove $15.9 million in cost savings from the Company's forecasted O&M expense" due to savings from the surge (6T 3775). The Company agreed in part, explaining that the $15.9 million includes three expense items: (1) Tree Trim Reactive, (2) Tree Trim Storm, and (3) Dist. Ops. Storm & Trouble. The Company agreed with the AG that O&M should be reduced by savings from Tree Trim Storm ($3.6 million) and Dist. Ops. Storm & Trouble ($2.7 million). These items were inadvertently omitted from the O&M calculation, and this has been corrected by a $6.3 million O&M reduction (Hartwick, 5T 2162-63; Exhibit A-13, Schedule C5.6 Revised, page 1, line 20). The PFD found that "Mr. Coppola has appropriately identified the savings that should be used to offset the 2021 base restoration expense . . . There is no evidence from DTE's schedules that the additional savings from [Exhibit A-22, Schedule L1] line 4 have somehow been 'realized' by ratepayers, unless the historical expense levels are adjusted as recommended by Mr. Coppola' (PFD, pp 503-504.] The Company disagreed with the AG and the PFD's recommendation regarding Tree Trim Reactive because the savings are already accounted for in Exhibit A-22, Schedule L1, line 4 (the Company's tree trim budget that gets reduced year over year). Thus, the adjustment recommended by Mr. Coppola has already been made by the Company.

iii. Pole Top Inspections.

AG witness Coppola proposed a $2.3 million reduction in PTMM inspection O&M based on the cost of inspections in 2022. Company witness Robinson responded in table form to this and similar conceptual proposals by intervenors relating to distribution infrastructure that are incorrect or problematic on their face, or lack sufficient detail to be even thoroughly considered. Therefore, these proposals should be rejected (Robinson, 5T 2721-23).

The PFD found that Mr. Coppola's recommendation should be adopted, reasoning that it was based on Company data (PFD, p 512). The PFD's acceptance of a simplistic calculation based on historical data neglects the substantial amount of evidence that the Company provided regarding the enhanced pole specifications and inspection process (which aligns with industry best practices and will produce significant benefits; see generally DTE Electric's Initial Brief, pp 78-83). The Commission also previously directed:

> [A]s part of the company's next rate case, DTE Electric shall: (1) provide a thorough breakdown of the total pole inspection and test costs which are applied across all capital programs and subprograms, (2) support why these costs are appropriately classified as capital costs instead of O&M with reference or references to accounting principles and guidance, and (3) amend the classification of these expenditures, where appropriate, based upon the analysis. [November 18, 2022 Order in Case No. U-20836, p 471].

The Company complied with the Commissions directives and also changed its accounting policy, effective January 1, 2023 (plainly after 2022 which Mr. Coppola used and the PFD adopted for historical costs), to shift inspection costs associated with the PTMM program to O&M (Elliott Andahazy, 3T 530-31; Uzenski, 5T 1506-1507). Therefore, the PFD's proposed O&M disallowance should be rejected.

3. Community Lighting

The Company explained and supported Community Lighting O&M expenses (See generally, DTE Electric's Initial Brief, pp 192-95). MAUI witness Bunch proposed $0 for LED

washing (a $384,487 disallowance) apparently reasoning that no LEDs should need to be washed on a 10-year cycle (4T 922-24). The PFD agreed, reasoning that the LEDs "should already have been washed" (PFD, p 517). The Commission should reject this proposed disallowance because the cost is for luminaires that are slated for washing during the projected test year, and are reflective of the number of LEDs that were originally installed in 2014. There are also LEDs that fell behind the washing cycle due to the lack of crew availability during the COVID-19 pandemic and the severe storm seasons of 2021 and 2022 (Bellini, 5T 2663). Therefore, the Company's $384,487 request should be approved.

MAUI witness Bunch proposed that the Commission "approve total spending on Supervisory and Administrative staff in the projected test period of $1,279,807" (4T 925), which is a $1,328,358 disallowance. The PFD agreed, reasoning that the Company's position was unsupported and further speculating that the Company might be able to eliminate positions through productivity gains (PFD, p 57). The Company maintains that its request is reasonable considering (1) the increase in these costs is attributable to new positions that are critical to effective management of the Company's streetlighting program (Exhibit A-40, Schedule EE8); (2) the streetlighting team headcount has steadily declined from 2018 – 2023 (Exhibit A-40, Schedule EE9); and (3) inflation. Witness Bunch's reasoning that "an annual increase of greater than 10% is likely unrealistic and unjustified" (4T 925) is also speculative and arbitrary, so it cannot support a decision. [112] Therefore, the Company's $2,608,165 request should be approved. (Bellini, 5T 2664).

[112] In *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), our Supreme Court explained that "[t]he 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 proven must be taken as not existing, since a decision cannot be based upon conjecture. *Star Steel v USF&G*, 186 Mich App 475, 481; 465 NW2d 17 (1990); *see also, Skinner v Square D Co*, 445 Mich 153; 516 NW2d 475 (1994).

4. Uncollectible Accounts Expense

The Company originally projected $54,614,000 of uncollectible expense but agreed to $47,855,000 based on accepting the Staff and AG's cash-basis method, with necessary changes (See generally, DTE Electric's Initial Brief, pp 196-98). Staff originally proposed a $12,654,000 downward adjustment (from $54,614,000 to $41,960,000), which it revised to an $11,805,000 reduction to $42,809,000 (Staff Initial Brief, pp 83-85). The PFD "concludes that Staff's adjustment, as modified in its brief, should be adopted" (PFD, p 522).

The Company disagrees because two changes are required for Staff's original calculation: (1) the historical write-off ratio should be applied to proposed revenue instead of present revenue, and (2) Non-Energy Net Write-Offs should not be excluded from the calculation. Both of these changes are consistent with AG witness Coppola's calculation in Case No. U-20836, which the Commission adopted. Staff agreed with the second change, but not the first. The Company maintains that the first change should also be made, and the Company's projected amount of $47,855,000 should be adopted.

On a related matter, Staff recommended that the Commission encourage the Company to discontinue the sales of uncollectible accounts to third parties for purposes of collection, suggesting that there could be some potential double recovery (Revere, 7T 4617). The PFD found "Staff's concerns reasonable . . .The Commission should at a minimum require the Company to provide

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It is similarly well established that an agency decision may not be based on speculation. *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).

reports to Staff regarding debt sales, so that Staff can seek whatever rate remedies Staff believes appropriate" (PFD, p 857).

The Company disagrees because it has a responsibility, on behalf of its ratepayers, to attempt to recover uncollectibles through available collection processes including debt sales. The Company also disagrees with Staff's suggestion that there is a potential for double recovery in rates associated with a debt sale (Revere, 7T 4617). When the debt is sold, the proceeds reduce historical net write-offs that are used to set the bad debt expense that the Company is requesting to recover in rates, which eliminates any risk of double recovery.[113] Staff's related reporting requirement is similarly unnecessary and inappropriate (Griffie, 4T 2107-2108).

5. Regulated Marketing.

The Company explained and supported Regulated Marketing O&M expenses (See generally, DTE Electric's Initial Brief, p 198). The PFD adopts Staff's recommendation that regulated marketing O&M be reduced by $1 million attributable to the EV emerging technology fund (PFD, p 523). The Company notes that it proposed $1 million in O&M relating to its proposal to make the EV Emerging Technology Fund permanent. The PFD instead recommends extending the pilot for 5 years (PFD, pp 645-46). The Company agrees but requests a $1 million regulatory asset to do so (instead of O&M which would be appropriate for a permanent program, since the Emerging Technology Fund would remain a pilot). See also section VII. A. 5. ii, Emerging Technology Fund.

[113] Staff's Initial Brief, pp 151-53, reflects that "Staff agrees" that there is no potential for double recovery in rates associated with a debt sale; however, Staff goes on to suggest that there is a double recovery because the Company recovers uncollectible expense (reduced by proceeds from sales of accounts) and the party that buys the accounts might recover something from the non-paying customers. It is not clear to the Company how Staff's assertion that different amounts recovered by different parties would be a double recovery.

6. Corporate Support.

The Corporate Staff Group's (CSG) O&M expenses for Administrative and General (A&G) services (excluding employee benefit costs, and after rate case adjustments and normalizations) as allocated to DTE Electric were $196.2 million for the 2021 adjusted historical test period, and are expected to increase to $213.3 million for the projected period (See generally, DTE Electric's Initial Brief, p 199).

i. IT O&M Disallowances

DTE Electric's Initial Brief, pp 199-201 generally explained and supported the Company's IT O&M expense. Staff proposed a $5.2 million O&M reduction relating to capital expenditures that it proposes to disallow ($4.2 million for projects with Level 2 cost estimates, and $1 million for individual projects). Staff's Initial Brief, p 96, revised the $4.2 million to $3.15 million because only 75% applies to DTE Electric. This is correct to the extent there is an O&M disallowance (which there should not be).[114] The Company previously indicated, and maintains, that capital expenditures should be approved, and Staff's proposed O&M disallowance should also be rejected because Staff's proposed IT O&M reductions were not included in the Company's requested revenue deficiency. Instead, the Company's projected O&M is included in Administrative and General expense, and uses 2021 historical expense adjusted only for inflation (Uzenski, 5T 1519, 1564, 1567; Exhibit A-13, Schedules C5.10, page 1, line 3, column (j)).

[114] If the Commission were to decide to disallow any O&M expenses, then that disallowance should be reduced to the portion that applies to DTE Electric only. The IT O&M costs recorded at DTE Electric are based on the bill down of costs from the DTE Energy Corporate Services, LLC, or about 75% of the total ($3.2 million), as reflected by Exhibit A-36, Schedule AA1, line 21, column (g). Therefore, if the Commission disallows any O&M related to these IT projects, the amount should be calculated in accordance with column (g). (Uzenski, 5T 1564-65, 1567-68).

Staff also proposed an additional $44.04 million IT O&M disallowance, asserting that the Company only supported $20.82 million of its $69.09 million request (Rogers, 7T 4663). In addition to the discussion above (projected IT O&M is based on 2021 historical costs plus inflation, not individual project estimates), the Company disagrees with this disallowance because most IT O&M costs are not tied to capital projects and Staff's adjustment would eliminate more than 70% of IT operating expenses. (Uzenski, 5T 1564, 1568).

The PFD agreed with Staff's proposed disallowances, inaccurately suggesting that the Company did not support its position, and that certain categories of O&M costs are included in new projects, so there is no basis to have continuing O&M from historical operations (PFD, pp 528-30).

The Company disagrees. In addition to the discussion above, the record reflects that IT O&M expense consists of some expenses related to project work along with a much more substantial level of on-going and base operating expense not tied to specific projects, which includes cloud computing fees, software as a service, hardware and software defect remediation, business support services, and IT administration. The Company's 2021 historical IT O&M including both project work and base operating expenses was $63.0 million as reflected in the historical data provided in the current case. The Company just added inflation to this historical expense, resulting in its $69.1 million projection. Without funding for base operating IT O&M, the Company would not be able to run and maintain existing IT systems, which would impair the Company's ability to operate effectively in delivering safe and reliable service to customers. Importantly, approximately 35% of the projected IT expense is for payroll for IT staff who support daily operations. Thus, the Company appropriately calculated its projected expense as historical actual costs plus inflation, and Staff's proposed disallowance should be rejected. (Uzenski, 5T 1518, 1564, 1568-69).

It also bears emphasis that the Company is maintaining the status quo while the PFD/Staff propose to drastically cut payroll and other funding. DTE Electric 2021 historical IT O&M was $63 million increased only for inflation to $69.1 million in the projected test year. This forecasting methodology is the same as the Company's practice in past rate cases in which the costs have been historically approved by the Commission. Consistent year-over-year costs are hardly surprising, and Staff has long had the ability to audit these costs. The Company maintains that it properly responded to the issue that Staff raised, and otherwise carried its burden of proof. Therefore, the PFD/Staff's proposal to slash IT O&M by more than 70% should be rejected, and the Company's O&M costs (based on 2021 historical costs plus inflation) should be approved.

ii. Corporate Memberships

The Company acquires and maintains corporate memberships that help in its mission to provide safe, affordable, and reliable energy (See generally, DTE Electric's Initial Brief, pp 201-204). As relevant here, Company witness Morren described the benefits that the Company realizes through its memberships in industry associations, such as the Electric Power Research Institute (EPRI), and the Low Carbon Resource Initiative (LCRI), which is a five-year joint effort between EPRI and the Gas Technology Institute (GTI) aimed at accelerating the development and demonstration of low and zero-carbon energy technologies (Morren, 5T 2368-69).

Staff proposed a $0.6 million disallowance for the LCRI membership (McMillan-Sepkowski, 7T 4581). The PFD agreed (PFD, p 537).

The Company disagrees because the costs to perform even one of the EPRI projects would be greater than the cost of membership. Following guidelines offered by EPRI also protects power plant equipment and maintains reliable operations. The economics of membership and customer benefits apply equally to the LCRI. Moreover, participating in initiatives where the Company can

learn from industry partners and projects in other service territories is a critical step in advancing emerging technologies that will support the net-zero goals set by the Company and the MI Healthy Climate Plan (Morren, 5T 2368-69, 2428-29).

Staff also indicated a belief that LCRI membership would only concern corporate goals and not customer benefits. It is true that LCRI membership would advance net-zero goals set by the Company and the MI Healthy Climate Plan, but it is also reasonable to believe that customers share these goals and would similarly benefit, and that customers would also benefit from the achievement of the goals. Customers would also benefit from the economics (membership costs less than a project) and the Company's ability to learn from industry partners and projects in other service territories (Morren, 5T 2368-69, 2428-29).

Therefore, the Company's request for $0.6 million for LCRI membership should be approved.

The PFD's suggestion that the Company provide additional information on customer benefits in its next rate case (PFD, p 538) should be rejected as unfounded and unnecessary. The Company already provided additional information in the instant case, and there is no sound basis for yet another filing requirement.[115]

[115] In the Company's last general rate case, the Commission "direct[ed] DTE Electric to file in its future rate cases an exhibit containing an itemized list of projected costs associated with membership fees and justification for why these costs are in customers' interest" (Case No. U-20836 Order dated November 18, 2022, p. 308). Ms. Crozier responded by explaining, among other things, that the Company acquires and maintains corporate memberships that help in its mission to provide safe, affordable, and reliable energy. Exhibit A-27, Schedule Q1 includes the costs and a description for each corporate membership included in DTE Electric's O&M expense for the projected test year. Pages 1-2 of Exhibit A-27, Schedule Q1, display the memberships that are non-discretionary. Pages 3-7 of Exhibit A-27, Schedule Q1, display the memberships that are discretionary. The descriptions include the benefits of the memberships. Also, corporate memberships that are non-discretionary and exceed $100,000 are further supported by other witnesses representing the primary business unit that utilizes the membership. Exhibit A-27, Schedule Q1 provides the witness names and associated business units (Crozier, 5T 2187-89).

7. Pension and Benefits

i. Other Post-Employment Benefit (OPEB) Expenses

DTE Electric's OPEB costs are projected to decrease from a negative $31.445 million in the historical test period to a negative $36.435 million in the projected period, or negative $21.424 million, inclusive of the effects of costs capitalized and transferred (Cooper, 5T 1356; Exhibit A-13, Schedule C5.12.2). The Commission previously approved the Company's proposal to defer negative OPEB expense to a regulatory liability (Case No. U-17767 Order dated December 11, 2015, p. 69), and to continue that deferral in subsequent cases. The Company proposes the continued deferral of the negative net OPEB expense consistent with prior treatment. If net OPEB expense becomes positive in the future, then the expense will be charged against the regulatory liability. Therefore, the negative OPEB expense is not included in the Company's proposed revenue requirement, and there is no obligation for the Company to fund its OPEB liability (Cooper, 5T 1356-57; Uzenski, 5T 1503-1504; Exhibit A-13, Schedule C5.12.2, line 18).

The PFD appropriately recommended "the continuation of the deferral for OPEB expense incurred in 2023 and future periods to mitigate the uncertainty underlying future expense" and as consistent with the Commission's decision in Case No. U-20836 (PFD, p 544-45), but agreed with AG witness Coppola's proposal that the Company begin to amortize the deferred OPEB balance of $128,416,000 as of December 2022 over a seven-year period, and include the resulting amortization expense of $18,345,000 in the projected test year as a reduction to O&M expense (PFD, p 543).

In addition to the benefits included in each membership's description, the benefits that the Company and its customers receive from the memberships listed in Exhibit A-27, Schedule Q1, pages 2-7 generally fit into one or more of the following categories: Benchmarking; Best practices; Research; and Networking (Crozier, 5T 2189-90).

The membership costs associated with the organizations listed on Exhibit A-27, Schedule Q1 do not include lobbying activities (Crozier, 5T 2189-90). Ms. Uzenski further explained how certain memberships and membership costs were excluded from customer rates (5T 1490; Exhibit A-3, Schedule C14).

The Company disagrees with the PFD and AG's amortization proposal for two reasons. First, the inclusion of a negative cost in the Company's revenue requirement would have a detrimental impact on the Company's future cash flows since the Company's revenue and cash receipts would be reduced without any corresponding reduction in cash outlays. Second, the proposal assumes a level of future expense that is difficult to forecast with any certainty, and changes in asset returns and discount rates could result in positive expense. Projections are based on the assumptions regarding the expected return on assets and discount rates, which could change. More specifically, as reflected on Exhibit AG-1.58, page 4, these estimates assume expected returns on assets that might not materialize and no change in discount rates during the projected period, which could again result in positive OPEB expense (Uzenski, 5T 1565, 1576-77).

ii. New Hire VEBA Expense

Staff proposed a $2.604 million reduction in the Company's projected New Hire VEBA expense. Company witness Cooper rebutted this by correcting Staff's calculations to reflect the impact on the Company's historical New Hire VEBA expense arising from the increase in the proportion of these costs that are capitalized and the exclusion of the 2020 results from the historical average due to the impact of the COVID-19 pandemic. The ALJ recommended adoption of the Company's correction to Staff's proposed New Hire VEBA, which produces a projection of $13.338 million (PFD, p 548). However, Appendix C in the PFD reflects the Staff's adjustment to the New Hire VEBA expense of $2.604 million. Therefore, the ALJ's recommended revenue deficiency should be corrected by the difference between the Company's rebuttal projection, as adopted by the ALJ, of $13.338 million and the Staff's proposal of $11.363 million, or an increase of $1.976 million.

iii. Active Healthcare Benefits

DTE Electric incurs substantial costs to provide benefits to its active employees. These costs largely concern health care and are projected to increase from $51.269 million in the historic test year, to $56.961 million [116] in the projected test year. This increase reflects the normalization of the 2021 historical Active Healthcare costs to reflect an historical average of constant dollar costs and thereby establish a sound starting point, which results in a decrease of $2.566 million (Exhibit A-13, Schedule C5.11.3). The 2021 normalized Active Healthcare costs of $48.703 million are then escalated for the adjusted medical plan trend of 6.0% in 2022, 5.5% in 2023, and 5.0% in 2024 (Cooper, 5T 1358-59; Exhibit A-13, Schedule C5.11, line 11). Witness Cooper further explained that annual unadjusted medical trend factors of 7.5% for 2022, 2023, and 2024 are based on projections for healthcare trends provided by the healthcare experts at Willis Towers Watson (WTW), as reflected on Exhibit A-13, Schedule C5.11.1.[117] WTW's trend factors are adjusted by 1.5% in 2022, 2.0% in 2023, and 2.5% in 2024 to reflect the expected savings from the Company's Wellness program, (to 6.0% in 2022, 5.5% in 2023, and 5.0% in 2024), and are corroborated by a study by PricewaterhouseCoopers LLP's (PwC) Health Research Institute (reflected on Exhibit A-13, Schedule C5.11.2), which projects that medical costs will increase by 7.0% in 2021, and 6.5% in 2022 (Cooper, 5T 1368-69. See generally DTE Electric's Initial Brief, pp 211-17).

The PFD states:

> This PFD agrees with Staff and the Attorney General that the Commission should reject DTE's constant dollar adjustment to healthcare costs; this approach is consistent with the Commission's past decisions rejecting the constant dollar approach as applied to active healthcare expense. Further, this PFD also recommends that the Commission continue to reject DTE's use of a national average rate of increase in healthcare costs instead of the actual average rate that DTE has

[116] The Company's projected amount for Active Healthcare is $64.553 million when life insurance and benefit plan administration fees are added. (Exhibit A-13, Schedule C.11).

[117] WTW first develops an Allowed Trend, which is then adjusted for the Company's actual plan design to develop the future Medical Plan Trend applicable to the Company (Cooper, 5T 1368).

> experienced, which is significantly lower than the national average. Indeed, even after DTE made downward adjustments to the national rate increase trend of 7.5% projected by WTW, DTE's proposed increases were still significantly higher than the utility's actual average rate of increase whether calculated by Staff or the Attorney General.
>
> This PFD recommends adopting Staff's revised Active Healthcare expense projection which applies the utility's actual 2.31% AAGR to DTE's historic test year expenses after removing the effect of DTE's constant dollar adjustment. This resulted in a projected active healthcare expense (apparently including plan administration fees and life insurance) of $61.854 million, which is $2.699 million less than DTE's total projection of $64.553 million. [PFD, p 558. Footnotes omitted.]

The Company maintains its position. In addition to the discussion above, the Company's constant dollar normalization is appropriate to establish an accurate starting point since the year-to-year volatility of actual Active Healthcare costs (which is largely driven by the Company's self-insurance of healthcare benefits, and changes in utilization) makes any historical period expense potentially unreliable as a starting point to project costs. The $2.566 million constant dollar normalization reduction to the Company's actual 2021 Active Healthcare costs is designed to eliminate this volatility and reduce the risk of selecting an unrepresentative starting point.[118] The volatility of the Company's actual Active Healthcare costs is graphically demonstrated on Table 1

[118] The mechanics (reflected on Exhibit A-13, Schedule C5.11) merely adjust the Company's historical Active Healthcare costs to a constant dollar basis. By analogy, the Constant Dollar approach is similar to the conversion of historical nominal prices into real prices because the value of a dollar changes over time due to inflation.

The Commission also adopted a similar approach in the May 8, 2020 Order in Case No. U-20561, p 86, rejecting the AG's exception to the use of a constant-dollar denomination for DTE Electric's emergent replacement expenditures, explaining in part: "Adding inflation to the five-year historic actual spend is appropriate for calculating the starting point for normalized expenditures"). The Commission also continued that treatment in the Company's most recent rate case (Case No. U-20836 Order dated November 18, 2022, p. 63). The constant dollar Active Healthcare adjustment follows the same logic (Cooper, 5T 1367).

The Company recognizes that the Commission recently declined to adopt a similar constant dollar normalization adjustment (Case No. U-20836 Order dated November 18, 2022, p. 288) and also declined a similar proposal for DTE Gas's Active Healthcare costs, "find[ing] a multi-year average adequately captures the volatility of the expense" (Case No. U-20940 Order dated December 9, 2021, p. 157). The Company disagrees, because averages of historical cost increases only measure annual changes in costs, which is distinguishable from determining the proper starting point from which projected increases are then applied (Cooper, 5T 1364).

of Company witness Cooper's direct testimony (at 5T 1360) where annual changes range from a 25.4% increase in 2021 to a 4.6% decrease in 2020. Such year-to-year volatility highlights the inherent flaw in solely using historical annual changes in the Company's actual Active Healthcare costs to project future increases (Cooper, 5T 1359-61, 1435-38).

This volatility is created by variations in usage, the effect of plan design changes, and changes in pricing. Moreover, due to the Company having less than 4,000 employees covered by the Company's self-insured medical plans, it only takes a few extraordinary claims to have a dramatic impact on the Company's Active Healthcare costs in any given year. Simply put, the population of the Company's employees covered by the Company's self-insured medical plans is just too small to infer that the experience over a few years is predictive of the Company's future costs. Accordingly, the adjusted trend factors of 6.0% in 2022, 5.5% in 2023 and 5.0% in 2024 reflected in Company witness Cooper's projected Active Healthcare expense, which are based on national trends, represent a superior source for predicting future increases than the Company's historical annual changes as it is a better predictor of overall trends and costs (Cooper 5T 1350-1362, Exhibit A-13, Schedule C5.11.1, page 4).

The PFD and Staff's projected Active Healthcare expense is also understated because it relies on historical annual average percentage changes in the Company's Active Healthcare expense, which is distorted by changes in the proportion of the Company's Active Healthcare costs that are capitalized. As reflected on Exhibit A-37, Schedule BB6, the proportion of the Company's Active Healthcare costs expensed has decreased from 68.8% in 2016 to 61.2% in 2021 (meaning that the portion capitalized has increased from 31.2% in 2016 to 38.8% in 2021, representing the complement to the portions expensed). This increase in the proportion capitalized has a distortive impact on the historical annual increases, which are a result of the increase in the Company's capital

expenditures over the last five years. Inclusion of the impact of these historical increases in the proportion capitalized implies that the increases in proportion capitalized will continue to increase through the end of the projected test year. There is no basis for that presumption. Rather than rely on the average annual percentage change in Active Healthcare expense, Mr. Cooper proposed as a correction to the Staff's proposal suggesting that the basis for projecting future increases should be historical annual percentage increases in the Company's total Active Healthcare costs, unsullied by the impact of the changes in the proportion of those costs capitalized, as reflected on Exhibit A-37, Schedule BB6.[119] Based on the combined categories of all the components of the Active Healthcare costs used by Mr. Rueckert, the result is a five-year average annual increase of 4.4%, which produces a projected Active Healthcare expense of $65.684 million compared to the Staff's revised projection of $61.854 million. However, based on the use of separate cost categories that separates healthcare cost components (i.e., Medical, Dental and Vision) from the other cost categories included in Active Healthcare costs (i.e., Life Insurance and Benefit Administration Fees), the five-year average of the healthcare cost components is 6.3%. Combining the application of the five-year average of 6.3% for the healthcare cost components with the specific projections of Life Insurance (which is projected to increase by the 3% labor cost escalation assumption) and Benefit Administration Fees (which is projected to increase by the Consumer Price Index (CPI)[120]), results

[119] The use of the annual change in the Company's Employee Savings Plan and New Hire VEBA costs were also reflected in Mr. Cooper's corrections to the Staff projections for those items on Exhibits A-37, Schedules BB3 and BB4, because of the distortive impacts of the historical changes in the proportion of costs capitalized. The ALJ recommended adoption of Mr. Cooper's corrections to the Employee Savings Plan and New Hire VEBA projections (PFD, pp. 547-548, 550-551).

[120] The CPI is projected to increase by 8.10%, 4.20% and 2.50% for 2023, 2024 and 2025, respectively. Based on the projected increase in the Benefit Administration Fees through the end of the projected test year of $981,000, this results in an annual average percent increase of 5.2% ($981,000/$6.442 million=15.2%/2.92 years= 5.2%). It strains credulity to believe that the Company's Active Healthcare costs will increase by only 2.31% annually, or by less than half the annual overall inflation rate. In contrast, the Company's average annual projected increase in Active Healthcare expense through the end of the projected test year is 5.8% ($8.258 million/$48.703 million= 17.0%/2.92 years= 5.8%)

in a total Active Healthcare Expense of $68.828 million (Exhibit A-37, Schedule BB6 and Exhibit A-13, Schedule C5.11, page 2).

The PFD also disputed the Company's use of the adjusted Willis Towers Watson (WTW) annual trend rates of 6.00% in 2022, 5.50% in 2023 and 5.00% in 2024[121] because these trend rate assumptions are "still significantly higher than the utility's actual average rate of increase" (PFD, p 558). The Company disagrees. As indicated above, a national trend rate, as provided by WTW, is preferable to the Company's historical average because the national trend is not subject to the year-to-year variability of a relatively small population of plan participants. Since the Company's actual Active Healthcare costs can be disproportionately impacted by a small number of claims, recent experience is a poor predictor of the future (5 T 1361-1362). It is axiomatic that trend projections based on larger populations don't reflect that volatility. Second, an analysis of the Company's actual annual percentage increase in its Active Healthcare costs for the years 2016 through 2021, before the impact of the changes in the proportion of those costs capitalized, demonstrates the annual percentage change has varied from a reduction of 4.6% in 2020 to an increase of 25.4% in 2021, with a five-year average of 6.3%, which is greater than the adjusted WTW trend rates used by the Company (Exhibit A-37, Schedule BB6).[122]

(Exhibit A-13, Schedule C5.11, page 2 of 2). Moreover, the 2.31% annual escalation is lower than every single year's projected overall inflation as measured by the CPI.

[121] The annual trend rate provided by WTW was 7.50% for all three years, but this rate was reduced by 1.50% in 2022, 2.00% in 2023 and 2.50% in 2024 to reflect the expected savings to be achieved by the Company's Wellness program (5 T 1368).

[122] As explained by Mr. Cooper, the Company's analysis of historical Active Healthcare costs excluded the impact of a one-time credit in 2018. Staff averred that the impact of this refund should be included in the average annual growth rate because the refund was required by the Commission to be amortized as a reduction to the Company's costs. (See Case No. U-20162 Order dated May 2, 2019, p 91) This claim disregards that the Company's recorded Active Healthcare costs were understated in 2018 because of a one-time refund that was unrelated to Active Healthcare costs in 2018. The requirement by the Commission to amortize that refund by a reduction in the Company's future revenue requirements is independent of the distortive impact the refund had on the Company's Active Healthcare costs in 2018, and thus is properly excluded from the analysis on Exhibit A-37, Schedule BB6.

Another problem with the use of historical averages as a basis to project future increases is the extreme sensitivity of the time period selected. For example, while the five-year average increase in Active Healthcare costs for the years 2016 through 2021 is 5.28%, a mere one-year shift in the period to the years 2018 through 2022 results in a five-year average of 3.96% (Exhibit A-37, Schedule BB8, Exhibit A-37, Schedule BB7). The shift of a single year in the period selected produces a 25% reduction in average annual rate of change that is purely a product of the time period selected and is not based on any new information regarding the future Active Healthcare cost expectations. While historical annual average percentage changes may be useful for costs that demonstrate a long-term trend, they provide little insight for costs that are highly volatile, such as Active Healthcare costs, especially when external projections are available (5 T 1437-38).

For the forgoing reasons, the Commission should approve the Company's initially requested $64.553 million Active Healthcare expense, which reflects the constant dollar reduction of $2.566 million and annual escalations of 6.0%, 5.5% and 5.0% for the years 2023, 2024 and 2025, respectively. This is reasonable because it is less than the $68.828 million derived by correcting the Staff's proposal (Exhibit A-37, Schedule BB6, line 41).

8. Employee Compensation

DTE Electric takes issue with three recommendations of the PFD relating to the Company's incentive compensation programs for both its executive and non-executive employees (PFD, pp 564-65).[123] First, DTE Electric seeks to recover the $62.903 million net projected test period

[123] The programs consist of short-term incentive plans provided through the Annual Incentive Plan (AIP), applicable to executive level employees, and Rewarding Employees Plan (REP), available to all other non-represented employees. In addition, the Company provides a multiple-year incentive plan delivered through the Long-Term Incentive Plan (LTIP), which is generally available to managers and above, and up to 10% of other non-represented employees. Company witness Cooper provided a detailed description of the design and mechanics of these plans (Cooper, 5T 1387-95; Exhibit A-21, Schedules K1 through K6 Revised).

incentive compensation expense, which excludes the expense allocated to the Company for DTE Energy's top five executives. (Cooper, 5T 1383-84). The performance measures included within the plans incorporate both operating and financial metrics. See generally, DTE Electric's Initial Brief, pp 217-26, which discusses incentive compensation in detail.

Staff proposed to exclude $43,821,000, representing the entire incentive compensation expense related to financial measures, acknowledging that "Staff does not dispute the overall reasonableness of employee compensation" and "Staff's position is based on long-standing Commission precedent" (Staff Initial Brief, pp 86-87).[124] The PFD instead indicates a view, without specific citation, that costs associated with meeting financial targets should not be recovered because the Company already receives funding to support operations and that funding allegedly should result in additional O&M savings (PFD, p 565). The Company maintains that the Commission has based its decisions on the evidence (*e.g.*, April 17, 2018 Order in Case No. U-18255, p 49) and has expressly recognized that "each case must be evaluated on the record in that case" (January 31, 2017 Order in Case No. U-18014, p 85). The Company further maintains, as indicated above, that it has appropriately reflected O&M savings in this case, and its general objection to the PFD not explaining its indicated views as required by MCL 24.281(2).

DTE Electric's proposal to include incentive compensation expense related to both the operating and financial measures is fully supported by the record in this case. DTE Electric provided

[124] Staff's proposed $43.821 million disallowance includes $0.422 million of Long-Term Incentive plan (LTIP) expense dependent on Nuclear Generation business unit operating measures. This proposed disallowance is improper even under Staff's reasoning because these operating measures (the INPO Index and Nuclear On-Line Capability Factor) are unrelated to financial results, and therefore meet the Commission's traditional practice of requiring quantified customer benefits through improved reliability and lower costs (Cooper, 5T 1408-10). Staff's Initial Brief, p 89, acknowledged that "Nuclear Generation incentive compensation is . . . **80% based on operating measures**" (Emphasis added). Thus, even assuming for argument's sake that incentive compensation based on financial measures should be disallowed, still only 20% should be disallowed here.

an in-depth cost/benefit analysis demonstrating a $25.044 million net customer benefit ($87.947 million total customer benefits minus $62.903 million total incentive plan costs). (Cooper, 5T 1398, 1403; Exhibit A-21, Schedule K6 Revised). While the calculated benefits of the incentive compensation plans result in a net customer benefit, these calculations do not include the unmeasurable benefits of the Company having a competitive total compensation program that allows it to attract and retain talented and qualified employees. Incentive compensation programs are an increasingly prevalent practice among the vast majority of energy companies.[125] Therefore, DTE Electric must also offer incentive compensation opportunities to be competitive with other employers in attracting and retaining talented and qualified employees. The record further demonstrates that DTE Electric's incentive compensation programs allow the Company to attract and retain talent at a reasonable cost relative to its peer companies. No party provided evidence whereby the Commission could determine that the *total* annual compensation of DTE Electric employees is unreasonable or imprudent. Further, the focus on the variable portion of total compensation is also inappropriate because DTE Electric's incentive programs are not additional compensation over and above what other companies pay for similar jobs. Instead, DTE Electric's incentive compensation programs are one of two components that make up DTE Electric's total annual compensation package, which is comparable to other companies competing for the same employees (Cooper, 5T 1375-76, 1384, 1411-12).

This point bears emphasis because failing to approve total incentive compensation expense is inconsistent with the reasonableness of total compensation. DTE Electric's analysis of virtually all incumbent salaries as of December 31, 2021 shows that the Company's total compensation is

[125] A 2021 study by WorldatWork and Compensation Advisory Partners indicates that the vast majority of companies have both short-term and long-term incentive programs. Moreover, a 2018 study by Aon of U.S. Salary Increases shows that 90% of Power and Gas Service providers utilized broad-based incentive compensation programs (Cooper, 5T 1385-86).

insignificantly different from market medians (Cooper, 5T 1381-82, 1412; Exhibit A-21, Schedule K1). Moreover, without the Company's short-term incentive compensation programs, the Company's pay would be 11.8% less than the market medians (Cooper, 5T 1382) making the Company less competitive in the employment market.

Without the prospect of total annual compensation equal to the fixed plus the variable compensation components, DTE Electric would not be able to attract and retain a highly-skilled workforce, or provide incentives for its employees to engage in activities that benefit customers because total compensation would be substantially less than the peer companies. DTE Electric's incentive compensation programs also allow the Company to provide a lower level of base pay. If DTE Electric were to eliminate the variable element of compensation, then DTE Electric would need to provide a commensurate increase in base pay to attract and retain a highly-skilled workforce. This would increase the cost of employee benefits, such as life insurance and the Savings Plan, which are based on annual salaries (Cooper, 5T 1375-76, 1384-85, 1411).

Customers benefit every day from employees who have the requisite skills and experience to ensure the delivery of quality customer service. DTE Electric's compensation philosophy and framework benefit all customers by providing a high level of service at competitive costs, with properly compensated employees having an at-risk element of compensation that provides incentives for safe, reliable, and efficient utility service that benefits every customer. (Cooper, 5T 1376, 1384-85).

The Company's second disagreement with the PFD relates to Staff's further proposal for a $6,534,000 disallowance of Restricted Stock expense. Staff reasoned that it relates to the achievement of financial performance measures. (McMillan-Sepkoski, 7T 4579-80). The PFD agreed (PFD, p 564). The Company disagrees. Company witness Cooper explained that the LTIP

has two components (Performance Shares and Restricted Stock). Performance Shares, which represent $25.234 million of the Company's projected LTIP expense, are granted annually as detailed on Exhibit A-21, Schedule K5. In contrast, Restricted Stock, which represents $6.534 million of projected LTIP expense, is granted annually to encourage continued employment of certain key executives, and the value of what is granted is *not dependent on the Company's achievement of any financial measures*. Therefore, the PFD/Staff's proposed disallowance is unfounded and should be rejected (Cooper, 5T 1394-95, 1408-1409).

Staff's proposal is also apparently based on an incorrect inference. Staff's Initial Brief, p 90, partially quotes the Company's LTIP employee plan description booklet (Exhibit S-9.2), but neglects to recognize that the booklet describes the potential benefits to employees of future increases in DTE Energy's stock price. That potential future benefit has no effect on the amount of the Company's corresponding costs. Again, the amount is unchanged regardless of whether it is paid in cash or stock. The potential future gain on stock is irrelevant, just like the potential future gain that the employee could get on a cash payment by putting it into some other investment (Cooper, 5T 1410, 1412-14).

The PFD responds that "DTE's arguments regarding the restricted stock program ignore the 'restricted' part of the 'restricted' stock grant; the restrictions discussed in Exhibit S-9.2, page 4 show that the grants provide financial incentives consistent with those of the company's shareholder's during the period of restriction" (PFD, p 564).

The PFD's reasoning acknowledges the Company's point that the *expense* is *not* related to financial metrics, but inconsistently declines to act on it by disregarding the temporal context. Employees benefit *after they receive stock* (assuming they keep it), depending on the Company's performance. That has nothing to do with the issue here, which concerns the *employees getting that*

stock in the first place. The cost of the awards (value when paid) does not depend on the DTE Energy stock price. That is all that is relevant here because the issue is cost recovery. It is certainly true that to the extent that somebody keeps the stock (during the "period of restriction" as the PFD reasons), the future value would depend on the stock price. But that future potential value is irrelevant to the Company's costs and independent of the grant itself. The stock price is not used to measure the awards; instead, the stock is used as the form of payment to deliver the awards (like dollars, bitcoin or other methods of payment). The number of shares used to pay the LTIP grant is simply adjusted depending on the stock price when the grant is paid. The amount of payment is the same regardless of how it is paid. The method of payment does not somehow change the payment (which remains the same in amount) into a financial measure (Cooper, 5T 1410).

For simple example that the PFD/Staff's disallowance is contrary to the relevant facts and based on faulty reasoning, a $1,000 grant could be 10 shares of $100 stock, or 20 shares of $50 stock. Either way, the expense is $1,000, regardless of DTE Energy's stock price. Plus, the whole point of this discussion concerns DTE Electric's recovery of expenses (here, measured at the time of the grant). Whether employees ultimately make or lose money based on DTE Energy's stock price in the future is irrelevant.

The Company's third disagreement with the PFD relates to AG witness Coppola's proposal to exclude 48% of incentive compensation expense relating to operating measures based on his analysis of the operating performance levels achieved for the years 2018 through 2022 (6T 3791; Exhibit AG-1.57). Company witness Cooper explained that Mr. Coppola's analysis is flawed because it failed to recognize that while certain measures may produce results less than Target, other measures can produce results greater than Target. There are also various gradients of performance between Threshold and Maximum. Exhibit A-37, Schedule BB1 shows that for the

last five years, the actual weighted performance was 87.1% for the AIP, and 77.6% for the REP (Cooper, 5T 1416-18).

This average annual performance method is more accurate than Mr. Coppola's simplistic binary approach (either the target was met, or not), and it recognizes that actual payouts can fall within a wide spectrum of performance levels. It is not reasonable to assume that only 52% of operating performance measures will be achieved as the AG suggests. The Company's goal is to establish costs at levels that are likely to be achieved, so it is reasonable to assume that the Company will, on an overall basis, achieve Target performance levels (Cooper, 5T 1418).

The Commission previously relied on similar evidence to reject essentially the same argument that the AG repeated in this case. The Commission instead authorized DTE Electric's recovery of incentive compensation relating to operating measures, explaining in part: "The Commission notes that DTE Electric provided evidence showing that the company has achieved performance targets for AIP at an average of 96.3% and for REP at an average of 82.8%, from 2012 to 2016. (7T 837). When looking at historical performance over a longer period, the Attorney General's recommendation that 50% should be disallowed is simply not supported." (Case No. U-18255, 4/18/2022 Order, p 49; see also Case No. U-20162, 5/2/2019 Order, p 93.) Indeed, the Commission has ordered in the past that incentive compensation be recoverable based on the type of programs that DTE Electric has developed and the type of evidentiary record that DTE Electric has presented in this case.[126]

[126] The Commission long ago recognized that: "Executive bonuses have often been viewed as an appropriate cost of operating a utility." (Case Nos. U-10149 and U-10150, 10/28/1993 Order, p 57) (rejecting the ALJ's total exclusion recommendation; adopting Staff's 50/50 sharing proposal; and advising DTE Gas that "future approval of an incentive bonus plan like this requires a showing that it will not result in excessive costs and that the benefits to the utility's ratepayers will be commensurate with those costs"). See also, for further example, Case No. U-17767, where the Commission approved DTE Electric's recovery of costs attributable to operating measures, stating that:

The Company recognizes that in its most recent rate case, the Commission adopted the AG's proposed 40% disallowance of operating measures (Case No. U-20836, 11/18/2022 Order, p 301; Case No. U-20940, 12/9/2021 Order). The Commission further stated: "In addition, the Commission authorizes DTE Electric to implement a two-way tracker mechanism, which will require refunds to customers if the 60% target level is not achieved or will allow the company to recover additional funds if it exceeds the 60% target level, up to a maximum of 100% target level. DTE Electric shall record the over- or under recovery, compared to the 60% base, in a regulatory asset or regulatory liability to be included in the company's next general rate case." (Case No. U-20836, 11/18/2022 Order, pp 301-302).

The mechanism is unnecessary if the Commission approves the Company's requested recovery. If the Commission approves a lesser amount, however, then the Company would request that the deferral be continued, but with three modifications. First, the base amount should be reset equal to the amount of incentive compensation approved for recovery in base rates in this case. Second, the mechanism should apply to the totality of the Company's incentive compensation program, including the portion related to financial metrics, since the Company's compensation practices are reasonable and prudent, as discussed above. Third, the deferral should cover the total actual payout, including amounts above 100% of the target. The incentive program allows for a range of payouts from zero to 200% of target. The incentive program is designed to motivate employees to achieve results beyond the target, further improving organizational performance and benefitting customers. Since the Company would be mandated to provide a refund to customers if

> [I]n the immediate case, the Commission finds that DTE Electric provided convincing evidence that the operating (non-financial) measures for the AIP and REP provide appreciable benefits to customers, and meet the standard set forth in the April 28, 2005 order in Case No. U-13898 (April 28 order) and the December 23, 2008 order in Case No. U-15244 (December 23 order)… [Case No. U-17767, 12/11/2015 Order, p 76.]

results fell below the baseline, it is reasonable to include the cost of achieving exceptional results (Cooper, 5T 1419-20; Uzenski, 5T 1551).

The PFD states:

> This PFD also finds that it is reasonable for the Commission to continue with the deferral approach it adopted in Case No. U-20836, using the percentage determined by Mr. Coppola [presumably meaning the 48% he calculated in this case]. There has not been sufficient opportunity to evaluate whether that deferral reasonably protects ratepayers from performance on operating measures that is below target level. DTE's arguments regarding asymmetry are rejected because the Commission has never approved ratepayer funding of performance above target level, and it is not clear that should DTE exceed one performance target and not meet another target, ratepayers would benefit to the same extent. [PFD, p 565.]

The Company maintains that the 48% disallowance for operating measures is inappropriate, and the Company's proposed modifications to the deferral mechanism should be adopted (which would be unnecessary if the Commission approves the Company's requested recovery). As described by Mr. Cooper and reflected on Exhibit A-37, Schedule BB1, the combined payout weighted Operating results for the last five years was 82.4%, which is in stark contrast to the simple average of 52% computed by Mr. Coppola (5 T 1417-1419). The PFD's further assertions about asymmetry have no basis in the record, nor is there a basis for the PFD's allegations that customers might not benefit from the achievement of operational measures beyond target levels (see also section II above).

Therefore, the Commission should reject the PFD's proposals as discussed above, and approve DTE Electric's request to include all the Company's incentive compensation expense (except for the top five DTE Energy executives) in the revenue requirement adopted in this case.

X. OTHER REVENUE RELATED ISSUES

A. Pilot Programs

1. Slocum BESS Pilot

Slocum Battery Pilot (Exhibit A-12, Schedule B5.1, page 2, line 51) is a pilot to replace the diesel-fueled peakers at the Company's Slocum peaker site located in the City of Trenton with a 14MW / 56 MWhr lithium-ion (Li-ion) Battery Energy Storage System (BESS) that will store excess energy that is generated on the grid during off-peak hours. This energy will then be available for dispatch during higher-priced peak hours (Morren, 5T 2291). The Company presented this pilot in its previous rate case, where the Commission ordered partial recovery and noted its expectation for a further discussion in this case, relevantly stating:

> [T]he Commission finds the Staff's confidence in the reasonableness of the project persuasive and adopts the Staff's partial disallowance for the bridge period and full disallowance for the test year to address the company's lack of support for changing and fluid project costs [citing record and noting that the proper disallowance amount was $28.187 million]. The Commission expects the company to present actual plans for the remainder of the project in its next rate case. [November 18, 2022 Order in Case No. U-20836, p 51.]

Accordingly, Mr. Morren sponsored Exhibit A-12, Schedule B5.1.1 (an update of Exhibit A-12, Schedule B5.1.3 from Case No. U-20836), which details the need, goals, design, expected pilot costs, stakeholder engagement process, and how the project is in the best interest of the public (Morren, 5T 2293). Mr. Morren also provided additional testimony on the substantial progress that the Company made on the project in 2022, and the Company's specific plans for 2023 and 2024, with BESS commercial operations starting in November 2024 (Morren, 5T 2291-93).

Staff continued to support the pilot, and generally found that the Company's additional information satisfies the Commission's directives from Case No. U-20836 (DeCooman, 7T 4368-69), but "recommends partial disallowances of $932,000 and $975,000 in projected capital

expenditures in the 2022 and 2023 bridge period, respectively, and a partial disallowance of $1,633,000 in projected capital expenditures in the 2024 test year" (DeCooman, 7T 4370). The PFD agreed, stating:

> This PFD finds that Staff's adjustment should be adopted for this project. Staff's concern for the accuracy of the company's spending projections is reasonable and Staff's recommended adjustment is a legitimate and appropriate means to protect ratepayers from paying the cost of over projections. There is no "asymmetry," as also explained in section V above, because DTE's overspending in a particular period does not raise a concern that the company's future projections are understated, and to the extent DTE's future projections are understated, actual expenditures that are determined to be reasonable and prudent will be included in rate base in a future case. [PFD, p 575. See also, p 108.]

The Company maintains that Staff's proposed disallowances should not be adopted. In addition to the discussion above, the Company appreciates Staff's continuing general support, but disagrees with Staff's calculation of a partial disallowance by applying the percentage of expenditures underspent (rate case forecast vs. actual) on the project in 2022 to the Company's projections. It is inappropriate to assume that because a project is underspent in a year, the projection for future years should be adjusted downward by the percentage underspent in the prior year. The methodology is also unjustly asymmetrical, since Staff does not apply an upward adjustment where actual spending is greater than the rate case forecast (as reflected, for example, in Exhibit A-35, Schedule Z5, for the Monroe Dry Fly Ash Conversion (ELG) project). Therefore, the PFD/Staff's proposed disallowances based on this methodology should not be adopted (Morren, 5T 2398-99).

2. C & I BESS Pilot

As discussed previously in Case No. U-20836, DTE Electric's battery energy storage pilot is a behind-the meter (BTM) lithium-ion battery storage system (BESS) at two C&I customers'

sites.[127] The Commission disallowed the proposed funding but encouraged the Company to resubmit the proposal (November 18, 2022 Order in Case No. U-20836, p 316). Based on this direction, the Company resubmitted its proposal with additional detail. The Company has selected Hitachi as the specific equipment provider and pilot integrator. The batteries have left the factory, and the Company has ordered all other major equipment for the BESS. The prospective customer intends to leverage the battery to reduce peak demand charges. The Company will also leverage the battery for demand response events (Farrell, 5T 1318-20). Due to lead time of major equipment, installation at the first customer's site has taken longer than anticipated but is planned to take place in Q3 2024. The Company plans for both batteries to be operational by the end of 2024 (Farrell, 5T 1331). Therefore, the Commission should approve the requested recovery (Farrell, 5T 1318-20).

Staff again is partially supportive, acknowledging the Company's progress, but recommending "disallowing one half of the pilot expenses" ($2.0 million) reasoning that "[b]ecause of the uncertainty about the second participant, Staff has concerns that only half of the program costs will be used and useful in the test year" (Matthews, 7T 4565-66). The PFD agreed, stating:

> This PFD agrees with Staff's recommendation that half of the requested program costs be disallowed. The pilot is designed to be used by two customers, with DTE having already purchased two batteries and corresponding equipment. However, DTE has only secured one customer for participation in this pilot. As only half of the participating customers have been identified by DTE, Staff's argument that half of the requested costs should be disallowed is persuasive. While DTE argues that the costs of both batteries are intertwined and have been incurred, Staff reasonably argues in its brief that in light of "the lack of a second participant at the time of filing, and the freedom the Company has as to when it files its rate cases, Staff

[127] The pilot is designed to test the ability to achieve peak demand shaving or shifting during demand response (DR) events, targeting C&I customers enrolled on Rates D4, D6.2 or D11 (excluding sites or load under Rider 10) since these customers are more suited to pilot participation due to their peak load profiles, outdoor space availability and operational capabilities. The pilot is appropriate and necessary because it allows the Company to gain experience with the application of storage technology by end-use customers and interactions with the wholesale market in order to develop well-designed tariffs and related pilot programs for customer-owned battery storage, as indicated by the August 11, 2021 Order in Case No. U-21032. The Company forecasts $4.0 million in capital expenditures in the bridge period of January 2022 through November 30, 2023, and $0.2 million during the projected test year (Farrell, 5T 1315-20, 1329).

> continues to support its recommendation to disallow half of the program costs give [sic] the uncertainty of finding a second participant." As of the time of this writing, DTE has only secured half of the customers it intends to use for the proposed pilot, it is therefore not reasonable and prudent to allow recovery of the full cost of the pilot when only half of the intended use of the program will be effectuated. Therefore, this PFD agrees with Staff's recommendation that half of the program costs ($1,990,360) be disallowed. [PFD, pp 583-84. Footnote omitted. See also PFD, p 343.]

The Company maintains that full cost recovery is appropriate and should be approved. In addition to the discussion above, the Company appreciates Staff's recognition of the Company's progress on this pilot, but disagrees with the proposed disallowance that simply splits the pilot's costs in half as that is not how the costs are incurred. The overall cost for both batteries was divided into milestone payments based on the project's key milestones, with the payment schedule for both batteries appropriately structured to avoid long lead time delays for equipment. A majority, 75%, of those milestone payments were already fulfilled in 2022. The remaining milestone payments for both batteries are planned for 2023 and 2024, covering the bridge and test year. The Company is confident that a second participant will be identified, and that the second battery will be installed shortly after the first. It is beneficial for the Company to fully complete the first installation so that the Company can use any learnings from that full installation to inform the process and installation for the second customer. The Company plans for both batteries to be operational by the end of 2024. Therefore, the Commission should approve full cost recovery for the pilot (Farrell, 5T 1330-31).

Staff also "recommends the Company charge some portion of the battery cost to the participating customer given the number of benefits and the amount of potential savings the C&I customer may receive from this program" (Matthews, 7T 4564). The PFD properly rejects this recommendation as premature, but further states: "However, this PFD recommends that should the pilot become a full program, a portion of the battery cost be charged to customers as the functionality of the program and savings realized will be assessed as part of the pilot" (PFD, p 585).

The Company disagrees to the extent that the PFD suggests a premature conclusion regarding a pilot that has not yet been run. The amount of savings that a customer will receive is unknown at this time. One of the pilot's objectives is to determine this as measured by peak demand charge reduction and subsequent bill reduction during the pilot period. If the Company moves forward with a full program after the pilot, then the Company could consider an appropriate subscription model for the battery based on actual bill reduction (Farrell, 5T 1331).

The PFD further states that "as DTE and Staff appear to agree that a minimum number of events should be called each year, this PFD recommends that a minimum number of events for the pilot be established" (PFD, p 586). The Company disagrees to the extent that the PFD suggests an inappropriate result. More specifically, Staff "recommends the pilot have a minimum number of events called each year to ensure all functions of the battery are tested by the utility and participating customer" (Matthews, 7T 4565). The Company generally agrees with Staff's reasoning that the Company should call sufficient events each year, but not the recommendation as stated. The initial proposed event schedule includes no more than 30 planned demand response events per year, and five emergency demand response events per year, with at least a one-hour customer notice. A minimum number of planned annual events will be discussed with the host customers, and the determination of that number will consider the objective of both the utility and the customer testing the battery functionality (Farrell, 5T 1332). Therefore, this issue will be appropriately resolved in accordance with general conceptual agreement, but the Commission should not order a minimum number of events as the PFD appears to suggest.

3. PrePay Pilot

In Case No. U-20836, the Company presented capital costs for its proposed voluntary PrePay Program, but also explained that a decision on approval of the program was pending in Case No. U-21087. The Staff and AG objected to the costs as premature. The PFD stated:

> This PFD finds Staff's analysis persuasive that the program will be evaluated in the separate docket, and if the company receives approval, which is uncertain given opposition in that case, it can then seek cost approval for the program. [U-20836 PFD, p 366.]

The Commission agreed, adding: "DTE Electric may seek these costs in a future rate case if and when the necessary approvals/waivers are eventually obtained." (Case No. U-20836 Order dated November 18, 2022, p. 206).

Although the Commission denied DTE Electric's request to implement its PrePay Program as presented in Case No. U-21087, it found that the concept has merit and that the Company could refile its request as a proposed pilot, stating:

> The Commission, however, finds that a prepay program could provide beneficial innovations for managing energy costs and consumption for certain customers if properly designed and vetted. Therefore, the Commission finds that DTE Electric may refile its request for a PrePay Program and associated waivers under the established objective criteria for approval of a pilot program and required comprehensive plan established by the October 29 [2020] order [in Case No. U-20645]. [Case No. U-21087 Order dated December 21, 2022, p. 17.]

Accordingly, the Company now requests approval for the implementation of its proposed voluntary PrePay Pilot, a waiver of certain MPSC billing rules (narrowed from the request in Case No. U-21087), and a recovery of $6.7 million of capital expenditures in the 2021 historical period (Exhibit A-12, Schedule B5.7.3, line 51). The Company has withdrawn its request to recover $2.6 million in the projected test year (Exhibit A-12, Schedule B5.7.3, line 52). (See generally, DTE Electric's Initial Brief, pp 253-60, 5T 1742).

The PFD recommends disallowing the requested $6.7 million, explaining in part:

> This PFD agrees with the positions taken by staff, the Attorney General, and the DAAO. Although DTE argues the changes made to the prepay pilot from its original iteration make it tenable, it cannot overcome the deficiencies cited by the other parties. [PFD, p 611.]

The Company maintains that the requested $6.7 million recovery is justified. The Company already invested the $6.7 million to build Phase 1 of its PrePay Program. This solution was deployed into the production CR&B system in December of 2021. The deployed solution includes all of the core functionality required to support a prepaid billing program, and can be used, with some configuration changes, to implement the proposed PrePay Pilot (5T 1743). Additionally, as presented in witness Hatsios rebuttal testimony, since the Pre-Pay Program solution was deployed in December 2021, the cost to ratepayers for the PrePay Pilot would not be the full capital recovery of $6.7 million due to the reduction from already realized depreciation of approximately $4.4 million, the cost of which is being borne by DTE shareholders. As provided for in Exhibit A-45 Schedule JJ3, the projected net book value of the project in November 2023 will be approximately $2.3 million, and by November 2024, it will be approximately $93,000. Therefore, the net average rate base included in the calculation of the revenue requirement would be approximately $1.2 million, and the cost to ratepayers through revenue recovery would be approximately $2.3 million. (5T 1786).

It is true that the Company's proposal faced opposition, but the Company appropriately addressed various concerns in designing its proposed pilot. The basic eligibility, structure, and management of accounts for the PrePay Pilot would be as described for Phase 1 of the proposed voluntary PrePay Program in Case No. U-21087; however, the Company considered the feedback that it received from Staff and intervenors, as well as the Commission's Order. Therefore, the proposed PrePay Pilot is designed to address, to the extent possible, their indicated concerns and recommendations, resulting in several differences from the PrePay program that was proposed in

Case No. U-21087. Some of the more notable changes from the program proposed in U-21087 are an enrollment cap of 3,000 customers over a two-year period, the exclusion of seniors, a lower arrears threshold of $250, an enrollment incentive, and extending the time to disconnect by 5 calendar days. (Hatsios, 5T 1744-48).[128]

The Company also incorporated lessons learned from its own "Pay As You Go" pilot (offered from 2011 through mid-2015) and other utilities with prepaid billing. (Hatsios, 5T 1765). The PrePay Pilot's design is summarized by Company witness Hatsios at 5T 1766, with further details about key design attributes at 5T 1766-67 (Eligibility), 5T 1767-68 (Enrollment), 5T 1768-69 (Account Management & Notifications), 5T 1769-71 (Disconnection/Reconnection), 5T 1771 (Customer Feedback), and 5T 1771-72 (Unenroll).

Staff indicated that the "changes from the Company's PrePay program as presented in Case No. U-21087 to this case has materially changed the program to a degree that Staff can no longer support such a program under the terms presented" (Klocke, 11). In addition to the discussion above, Mr. Hatsios addressed Staff's concerns related to the cost of the Pilot to ratepayers and the number and type of customers who would be eligible and interested in the Pilot in his rebuttal testimony, such as further explaining the size of the program relative to its cost to ratepayers, (Hatsios 5T 1785-1787; Exhibit A-45, Schedule JJ3), the number of potential customers who could enroll in the Pilot and the possibility of easily increasing the arrears threshold (Hatsios, 5T 1787-1789), and the use of customer feedback and the Company's own experience in developing the Pilot (Hatsios, 5T 1789-1791). The Company further notes, as also indicated at Staff's Initial Brief, p 51, that it attempted to address indicated concerns by both Staff and intervenors. While disagreements

[128] In accordance with the Commission's directives in the U-21087 Order (quoted above), the Company provided all of the applicable objective criteria established in Case No. U-20645 for its proposed PrePay Pilot (Hatsios, 5T 1743-44; Exhibit A-24, Schedule N11).

by and between Staff and intervenors may remain, the Company expended considerable effort to design a balanced and well-thought-out proposal that merits serious consideration.

The PFD's recommendation was also based on arguments asserting that there is not sufficient evidence of customer interest in the pilot (PFD, p 611). The Company maintains that there is sufficient customer interest in prepaid billing. In addition, other utilities are offering prepay programs or pilots to their customers (Hatsios, 5T 1750-54; Exhibit A-24, Schedule N18 (PrePay Customer Focus Group Results); Exhibit A-24, Schedule N19 (PrePay Consumer Survey Data). Mr. Hatsios further described the types of customers who might benefit from the pilot:

> The PrePay Pilot will provide all customers visibility and a greater sense of control over the energy they use and how much they spend, the ability to pay on a schedule that they establish and that better meets their needs, and a simplified billing experience. For customers who struggle to stay current on today's monthly post pay billing model, prepaid billing will provide them the opportunity to pay in smaller amounts and at a frequency that aligns with their ability to pay, to easily monitor their usage, and to conveniently have a portion of each payment they make applied to the reduction of their arrears balance. [Hatsios, 5T 1754.]

The Company has identified four specific customer segments that it expects to benefit from the PrePay Pilot: (1) tech savvy energy conservers, (2) financially stable savers, (3) renters and college students, and (4) payment troubled and vulnerable customers (Hatsios, 5T 1755-58; Exhibit A-24, Schedule N12). Potential customer benefits include reduced energy usage, a manageable way to pay down arrears, and ratepayer savings if the Pilot were to be expanded to 10,000 customers or more from reduced uncollectible expense and working capital that would be passed on in the ratemaking process. New customers beginning service with DTE Electric may also find the Pilot much easier to start service as compared to the traditional post-pay billing process (Hatsios, 5T 1759-64).

In addition to seeking approval of its PrePay Program in Case No. U-21087, the Company also requested a partial waiver of the Consumer Standards and Billing Practices for Electric and

Gas Service, Mich Admin Code, R 460.101 *et seq*. (billing rules). The Commission did not reach this issue, explaining: "The Commission further finds that because it is denying DTE Electric's PrePay Program application as presented, an evaluation of the requested waivers is unnecessary and might lead to confusion should DTE Electric choose to refile as a pilot program" (December 21, 2022 Order in Case No. U-21087, p 18).

The Company is therefore requesting waivers of billing rules to implement the PrePay Pilot. The rules and the applicable reasons for waivers are set forth at Hatsios, 5T 1772-73 (R 460.120(3)), 5T 1773-74 (R 460.129(4)), 5T 1774 (R 460.139(1)), 5T 1774-75 (R 460.139(6)), 5T 1775-76 (R 460.143(1)).

The PFD instead agreed with an argument that the Company did not explain how the requested waivers would be an effective and efficient administration of the rules, explaining in part:

> While Mr. Hatsios explained how the requested waiver of the Billing Rules would allow administration of the pilot, he does not explain how the administration of the Rules themselves would be furthered if the request is granted. Furthermore, this PFD does not find that DTE has provided evidence showing how a waiver of the Billing Rules in question would be in the public interest. Therefore, this PFD recommends that DTE's request for waiver of the select Billing rules should be denied. [PFD, p 614.]

The Company maintains its position, noting that Mr. Hatsios presented an extensive explanation in his direct and rebuttal testimony (5T 1772-77, 1792-93). It also bears emphasis that these are <u>not</u> the same waivers that the Company requested in Case No. U-21087. These waiver requests have been minimized as much as possible to address intervenor concerns about potential harms from the waivers requested in Case No. U-21087. The waivers requested in this case do not include notice of shut-off requirements. The main purpose of the waivers is to allow all notifications to be delivered via links in e-mails and text communications (Hatsios, 5T 1776). Mr. Hatsios further summarized why the waivers and the proposed pilot should be approved:

> The protections provided by the billing rules for which the Company is requesting waivers, are necessary in the post-pay model to help ensure customers are provided adequate opportunity to access funding, and if necessary, enroll in a payment plan to avoid shutoff. While this process plays out, today's post-pay customers continue to consume energy, adding to both their past due balance and their current amount due. For some customers, this cycle continues, over and over again, and still ultimately results in the disconnection of service for nonpayment.
>
> The prepay model flips the script and gives customers who enroll in PrePay the opportunity to pay what they want, when they want, based on their financial situation and their energy needs. To assist customers, and to ensure they can successfully maintain a credit balance and avoid being disconnected, the Company will provide relevant information to the customer in the form of the previously described daily balance updates, low balance alerts, and easy payment options, which includes notifications letting the customer know that they can contact DTE for assistance if necessary to avoid shutoff.
>
> Additionally, as described in the previously discussed PrePay Pilot eligibility requirements, the Company is excluding customers with a medical emergency at the premise, those with active military service, and any senior customers. Also, as described, the Company is adhering to the same disconnect rules that are in place today for post-pay customers (i.e., no shutoffs on weekends, or holidays, or during extreme weather). And finally, as I indicated, the PrePay Pilot is an optional program, customers can transition out of PrePay at any time with no penalty if they determine that the program is not providing them the benefits that they expected. [Hatsios, 5T 1776-77.]

The PFD also agreed with concerns that were asserted regarding the pilot's potential effects on low-income customers (PFD, p 613). These concerns are overstated and inaccurate. The Company acknowledges that low-income customers could view a pre-pay program as an attractive alternative, but the Company has designed the Pilot to appeal and provide benefits to a variety of customer segments, and is not specifically targeting low-income customers. In fact, to enroll in the PrePay Pilot, a customer must contact the DTE Contact Center and speak with a PrePay specialist, which provides benefits including allowing the Customer Representative (CR) to validate the customer's low-income status and determine if the customer is eligible for any energy assistance that would help them pay down their past due balance, and to determine if the customer is eligible to enroll in the Company's Low Income Self-Sufficiency Plans (LSP) or the Payment Stability Plan

(PSP). Only after exhausting all of these available options, would the CR offer the customer the opportunity to voluntarily enroll in the PrePay Pilot (Hatsios, 5T 1754-57, 1796-97).

The PrePay Pilot also offers enrolled customers protections including 24/7 access to their PrePay account balance and number of days remaining, low balance alerts including relevant Company contact information and links to energy assistance information, all of the same information that is provided to customers in the post-pay noticing and disconnect process, and a five-day grace period from the time a customer's PrePay account reaches a zero balance and the disconnection of service. (Hatsios, 5T 1768, 1797-98).

The PFD also "shares the opinion that the five-day grace period proposed by DTE is not sufficient to protect the interests of low-income and vulnerable customers afforded by the Billing Rules. This PFD further agrees with the argument that the need to make sure the energy account has adequate funds adds to the pressure of low income and vulnerable households" (PFD, p 613).

The Company disagrees. In addition to the discussion above, the Company designed the PrePay Pilot in a way that shows concern for customers by providing them with adequate time and options to avoid disconnection. All customers will receive low-balance alerts at 10, 5, 3, and 1 day prior to estimated exhaustion of their prepay credits. Customers will also have the option to receive daily balance alerts, and will have the ability to view their balance and the number of days remaining whenever they want, either online, through the automated phone system, or by calling the dedicated PrePay Pilot phone number (Hatsios, 5T 1768-1769, 1794).

The Company has also committed to provide PrePay Pilot customers at least five full calendar days between the time they reach a zero balance and when their service is disconnected (up to seven days if the fifth day falls on a weekend or federal holiday). Therefore, at a minimum, every participant will have at least 15 days after receiving their ten-day low balance notification

before they are disconnected. Plus, disconnection would only happen if they took no action to either replenish their account or request to return to post-pay billing, which they can do at any time (Hatsios, 5T 1770-1771, 1795).

It is also important to keep in mind that the essential point of running a pilot is to obtain information. It is therefore inappropriate for the PFD to presume unintended (and unlikely based on the evidence) results based on asserted concerns as discussed above, or to suggest the "catch 22" reasoning (e.g., at p 612) that the pilot should be disallowed based on a lack of information that would be obtained by running the pilot.

For all these reasons, the Company's PrePay Pilot should be approved. The Company appropriately responded to concerns in Case Nos. U-20836 and U-21087. There is extensive evidence that PrePay is an attractive voluntary alternative for customers who wish to gain more insight and control over their energy usage, or who struggle with paying their bills with today's post-pay billing model. The Company further maintains that the capital expenditures are reasonable and prudent, and has provided significant details about the design of the pilot, customer segments that might benefit most from enrolling, eligibility requirements, adequate noticing prior to disconnection, and other areas of concern that have been addressed in light of Case No. U-21087. Therefore, the Company's proposed PrePay Pilot and requests for capital recovery and billing rules waivers should be approved.

4. Delivered Fuel Electrification Pilot (DFEP)

DTE Electric proposes a five-year pilot to electrify space and water heating in homes currently heating with a delivered fuel, which includes propane, heating/fuel oil, diesel, or kerosene. At full enrollment, the Company would facilitate the installation of approximately 1,500 air source heat pumps (ASHPs), 300 geothermal heat pumps, and 300 heat pump water heaters (HPWHs)

(Peterson, 4T 761-62; Exhibit A-12, Schedule B5.10.1 summarizes how the DFEP meets the requirements of the February 4, 2021 Order in Case No. U-20645. See generally, DTE Electric's Initial Brief, pp 249-52). The PFD recommends that the Commission reject the pilot, stating:

> This PFD recommends adopting Staff's proposal to reject the pilot because of the myriad of issues or deficiencies identified both by Staff and by MNSC witness Neme. While this PFD does not regard all the ostensible deficiencies as serious, many are significant enough that they warrant rejection of the pilot as currently proposed. This PFD recommends that the Commission direct the utility to meet with staff and other stakeholders to develop a pilot design that could overcome the deficiencies identified by Staff and other stakeholders. [PFD, p 630. See also, pp 407-408.]

The Company maintains that the pilot should be approved, and disagrees with the PFD's "myriad of issues or deficiencies" characterization. The Company attempts to present a full discussion, since the PFD neglects MCL 24.281(2)'s requirements by not suggesting any particular reason why the pilot should be rejected.

Ms. Peterson explained that heat pumps can provide benefits including monetary savings to customers from lower lifetime operating costs, and significant emissions benefits. There are barriers to adoption in Michigan, however, including: (1) higher upfront costs; (2) lack of customer and contractor awareness; and (3) limited incentives to convert to a heat pump. The Company's overarching objective is to help delivered-fuels customers unlock operational savings and environmental benefits from heat pump systems, while integrating the additional load in a manner that benefits all of its customers (Peterson, 4T 763-68).

Based on learnings from its prior efforts and feedback from stakeholders, the Company proposes the DFEP with three primary components: (1) Education and Outreach (E&O); (2) heat pump rebates; and (3) program management. If the Commission approves, then the Company will seek to launch the pilot within six months, and anticipates that it would last five years. The Company seeks the following key learnings: (1) heat pump identification capabilities via AMI; (2) heat pump adoption rates by region; (3) rated versus actual performance of heat pumps in cold

climates; (4) customer and contractor perceptions and satisfaction with heat pumps; (5) refined cost-benefit analysis (CBA); and (6) the impacts to the grid. Similar to Charging Forward, the Company proposes to create and meet with a stakeholder group, and provide an annual status report to key stakeholders during the pilot (Peterson, 4T 770-76).

The Company requests a total of $6.1 million over five years, as shown in the table at Peterson, 4T 776. Total projected DFEP spend for the projected test year is $1.3 million (Exhibit A-12, Schedule B5.10, line 5, column (f)). The Company requests regulatory asset treatment for the duration of the pilot, which is consistent with the initial accounting treatment for the Charging Forward and eFleets pilots (Peterson, 4T 776; Uzenski, 5T 1549).

MNSC witness Neme suggested shortening the DFEP to three years, with a more aggressive ramp-up curve (6T 3501-3502). The recommendation is unnecessary and inappropriate because the Company has proposed regulatory asset treatment for DFEP costs, which has the benefit of flexibility in timing of spend to match program demand. The Company will adjust future year spend projections based on lessons learned after launch (Peterson, 4T 811).

The proposed DFEP benefits all customers in two key ways: (1) electric heat pumps have higher average cooling efficiency ratings compared to air conditioners, reducing overall load during DTE Electric's summer peak season, and (2) the increase in load seen by heat pumps occurs primarily during the off-peak season, when there is available capacity, and the additional usage spreads fixed costs. The Company estimates total net present value (NPV) gross margin benefit of $11.3 million (based on average NPV gross margin of $5,400 for each heat pump, and 2,100 heat pumps added due to the five-year program). Subtracting the program costs ($5.0 million NPV) yields approximately $6.3 million of overall NPV benefit (Peterson, 4T 777-78).

Staff indicated that "it is unclear how the cost of incremental power was determined" in the DFEP cost-benefit analysis (CBA), and suggested that the cost might not be accurate (Revere, 7T 4614-15). The cost of incremental power was determined by using base fuel and purchased power,

described as PSCR Base. The PSCR Base is the fuel and purchased power cost included in the Company's tariffed rates, and the Company's tariffed rates are the basis for the revenue calculation in the CBA. Any other representation of the cost of fuel and purchased power would be an apples-to-oranges comparison (Peterson, 4T 806; Willis, 5T 3180; Exhibit A-13, Schedule C4).

Staff also recommended to forecast and include potential additional power supply and distribution costs associated with the DFEP CBA (Revere, 7T 4615). The Company disagrees because these additional costs are very difficult to forecast, and very unlikely to be significant at the scale of the proposed DFEP. The Company does, however, agree to work with Staff and Interveners to address perceived deficiencies prior to launch in 2024 (Peterson, 4T 807).

Staff's Initial Brief, p 10, responded that it "may be the case" that "such impacts would be negligible," but a pilot should also be geared toward examining what a program would look like 'at-scale'. As such, ignoring these potentially substantial impacts is a fatal flaw." The Company maintains that Staff's assertion is overstated after acknowledging "negligible" impacts. The Company also agreed to work with Staff and Intervenors as indicated above so assuming for the sake of discussion there is a flaw, it is hardly "fatal."

Staff's Initial Brief, p 10, further asserted that "[t]he Company also failed to show why the exclusion of all other heating customers besides those served with deliverable fuel is appropriate." To the contrary, the Company explained that since electric resistance customers transitioning to a heat pump decrease net load, they are already (and more appropriately) served with programs from the Company's Energy Efficiency team, so DFEP incentives would be redundant and not beneficial. It is also not economic to electrify homes heated with natural gas at this time, even with incentives, so it would not be prudent to spend limited resources on those customers (Peterson, 4T 808).

MNSC witness Neme correctly assumed the Company's definition of low-income customers for the DFEP (those participating in "any existing low-income program, including the Company's energy waste reduction (EWR) programs and bill payment assistance programs"), but

he indicated a desire for broader coverage (6T 3503-3504). The Company is willing to modify the low-income definition for this pilot to align with the same eligibility criteria for the Charging Forward Income-Eligible EV Rebates (Peterson, 4T 809-10).

Witness Neme further recommended "to cover the full cost of new heat pumps for income-qualified households" (6T 3506). The Company disagrees because the rebates need to be sized to both incentivize adoption and manage pilot costs to ensure the incremental load provides a net benefit to all DTE Electric customers. The Company is willing to work with Staff and Intervenors to refine future rebate amounts to achieve the right balance between rebate levels and customer benefits (Peterson, 4T 810).

Witness Neme further recommended to "offer bonus rebates – i.e., dollars over and above what are available through its EWR programs – to non-low-income households that electrify their space heating" (6T 3512). The Company disagrees because customers are already eligible for building envelope efficiency rebates through the Company's EWR programs. Thus, increasing DFEP costs for EWR measures would be redundant and not beneficial (Peterson, 4T 810).

In summary, the various concerns that were raised generally lack merit and relevance, and at most indicate minor refinements to which the Company is agreeable. Therefore, they do not (even when viewed collectively as the PFD suggests) constitute a sound basis to reject the proposed pilot. The Commission should instead approve the DFEP pilot as proposed by the Company, with the Company continuing to solicit input from stakeholders during the pilot.

5. Electric Vehicle Pilots - Charging Forward

The Commission previously approved Charging Forward, and the Company is beginning to transition to permanent programs (See generally, DTE Electric's Initial Brief, pp 238-41).[129]

[129] The Company originally proposed to make Home Charger Installation (previously "Residential Charging as a Service" or "Residential CaaS") permanent. The PFD agreed with the Company's subsequent proposal to end Home Chargers Installation by the end of 2023, at which time the Company will transition the offering to a value-added

i. eFleet Battery Support

The eFleet Battery Support element concerns DTE Electric offering to purchase bus batteries on behalf of transit agencies to alleviate the upfront premium of electric buses, and the costs will be recovered over time on their monthly bills through Rider 21 (See the November 18, 2022 Order in Case No. U-20836, pp 339-41, discussing Transit Batteries/Electric Bus Batteries). The Commission also "encourage[d] DTE Electric to submit, in its next rate case, a proposal for the expansion of the transit battery/eBus batteries pilot that provides an opportunity for school districts to utilize this program to expand electrified school bus fleets" (*Id.* at 340-41). The Company has done so, but in addition, the Company's C&I customers – and Michigan overall – may benefit from including other, similar vehicle segments in this participant-funded program in order to evaluate the impacts. Therefore, the Company proposed to expand eFleet Battery Support and modify Rider 21 to include any vehicle registered to a business customer of the Company as long as the vehicle battery is greater than 150 kilowatt-hours (kWh), which would include vehicles such as refuse trucks and last-mile delivery vans (Peterson, 4T 725-27).[130]

MEIU witness Sherman asserted that eFleet Battery Support "provide[s] services to customers that could be provided by non-utility service providers and, as such, to the extent they are allowed, should be considered value-added programs subject to the Code of Conduct adopted by the Commission in Case No. U-18361" (6T 4151). The Company disagrees because the intent and structure of eFleet Battery Support is to provide a tariffed program under Rider 21 that ensures the program is participant-funded and overall neutral to rates, while helping to increase the adoption

program or service (VAPS) program (PFD, p 637). The cost reductions from the corresponding withdrawal of Rider 22 in the projected test year are $4.2 million in capital (Peterson, 4T 801).

[130] Accordingly, the Company proposes costs (which will be recouped over time pursuant to Rider 21) of $2.0 million in the 23 months ending November 30, 2023, and $3.0 million in the projected test year. The projected increased expenditures could support the deployment of approximately five electric transit buses in the bridge period, and 9-16 fleet vehicles in the projected test year, depending on the battery sizes and vehicles. The Company requests capital treatment consistent with the Commission's decision in Case No. U-20836 (Peterson, 4T 728; Exhibit A-12, Schedule B5.9, page 4, line 3, columns (e) and (f)).

of large EVs. Other approaches would likely not provide the same overall benefits (Peterson, 4T 800).

The PFD supported the Company's proposal and to allow the Company to transition the pilot to a permanent offering (PFD, p 642). The PFD also recognized that the record shows no problem, but nevertheless opined that the Commission should consider initiating Code of Conduct proceedings because it is conceivable that an issue could potentially arise:

> This PFD has reservations regarding MEIU's assertion that this program should be considered a VAPS under the Code of Conduct because the testimony offered by Dr. Sherman was conclusory and did not assert, let alone establish, that there actually are non-utility market participants with similar offerings to finance batteries for use in large EVs. Accordingly, it is not clear on this record whether DTE's program actually competes with non-utility market participants. However, it is conceivable that this program could compete with non-utility market participants, if not presently, then potentially in the future. Accordingly, this PFD acknowledges that the Commission should consider MEIU's recommendation to initiate informal proceedings under MCL 460.10ee(5) to determine if this program implicates the Code of Conduct. [PFD, pp 642-43.]

The Company disagrees with the suggested Code of Conduct proceedings based on the record showing no Code of Conduct problem as discussed above, and because the PFD's contrary suggestion is based on speculation. [131]

ii. Emerging Technology Fund

The Emerging Technology Fund allows the Company to efficiently test new technologies and prepare for widespread EV adoption in the future. The Company will also include a Staff member on the Advisory Committee, host regular meetings with the Advisory Committee, and

[131] *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).

document the element's results, including costs and benefits (Case No. U-20836 Order dated November 18, 2022, p. 346).

The Company proposed to make the Emerging Technology Fund permanent because the EV market is going to continue to rapidly evolve for the foreseeable future so there is a need for the Fund in both the short-term and long-term to keep pace with advancements, including battery chemistries, charger solutions, and software applications. Implementation costs are $0.9 million in the 23 months ending November 30, 2022 (regulatory asset), and $1.0 million in the projected test year (and annually, going forward, as O&M). The Company received regulatory asset accounting approval in Case No. U-20836, but sought O&M treatment as appropriate for a permanent offering (Peterson, 4T 728-30; Exhibit A-12, Schedule B5.9, p4 lines 12 and 22, columns (e) and (f)).

Staff stated that it "does not support DTE's Emerging Technology Fund becoming permanent . . . Staff still supports the concept, but until the program matures, is uncomfortable with it becoming permanent or receiving additional funding" (Staff's Initial Brief, p 8). The Company disagreed because the Company has made significant progress on the Emerging Technology Fund (ETF) since the Commission's November 18, 2022 Order in Case No. U-20836. If permanency is rejected, then the ETF should at least be approved for another five years (through 2028) to maintain the already meaningful momentum and collaboration in progress (Peterson, 4T 803). The PFD states:

> This PFD agrees with Staff's recommendation that the ETF should not be made permanent at this time because the pilot—which was only recently approved in DTE's previous rate case—is too new to evaluate its efficacy and value. However, this PFD also agrees with DTE's alternative proposal that it is worthwhile to extend the pilot for five years to maintain the progress already made and give this very new pilot time to demonstrate its value. [PFD, pp 645-46.]

The Company is agreeable to the PFD's recommendation to extend the pilot five years, but if the Commission does so, then it should provide corresponding funding. As indicated above, the

Company requested $1.0 million of O&M funding, which would be appropriate for a permanent offering. The PFD's Appendix C, line 17, reflects the removal of the $1.0 million in O&M. The PFD further states that since it "adopt[s] Staff's recommendation regarding the Emerging Technology Fund, this PFD concludes that Staff's recommended $900,000 reduction in working capital should correspondingly be adopted" (PFD, p 408). That would produce an incorrect result. The $900,000 relates to the bridge period ending November 30, 2023 (Exhibit A-12, Schedule B5.9line 22). If the Commission extends the pilot as the PFD recommends, then the Commission should provide the $1.0 million funding as a regulatory asset, which is appropriate for a pilot. See also section VI. B. 6, Regulated Marketing.

iii. Charging Hubs

Charging Hubs will allow the Company to directly pursue available federal and state grants, so another hub should be added to the presently-approved two hubs to maximize awards to the Southeast Michigan region that DTE Electric serves, and to further the MI Healthy Climate Plan. To ensure prudency, the Company will add receiving government subsidies as an additional buildout criterion. Also, the Company does not want to compete with third-party developers in the long-term, so the Company proposes Charging Hubs for an extended pilot only, and not as a permanent program (Peterson, 4T 740-41). ITC "supports the Charging Hubs program and its expansion" (ITC Initial Brief, p 4). Staff, EVgo, and MEIU indicated concerns and recommended that the Commission not approve expansion of the Charging Hubs program. The PFD states:

> This PFD agrees with the reasoning expressed by Staff and other intervenors; it would be hasty to approve a third charging hub before the two originally approved hubs have been built. However, this PFD recommends that the pilot should be extended with respect to the two previously approved hubs. [PFD, p 663.]

The Company agrees that the pilot should be extended, and maintains that a third hub should

be added. In addition to the discussion above, the Company understands the indicated concerns, and acknowledges that the deployment of the two approved Charging Hubs is delayed due to the Company seeking federal funding; however, the Company still believes that utility-owned Charging Hubs can help accelerate fleet electrification in Michigan. Also as indicated above, the Company added a criterion that federal funding be tied to any additional Charging Hub site that the Company constructs. This was added, in part, because the Company is uniquely suited to pursue federal grants and drive funding into Southeast Michigan. For example, the Company was instrumental in a Charging Hub in Redford Township receiving $8.5 million of federal funding, and the Company has applied for federal funding for another Charging Hub in Southwest Detroit. If the Company is not granted approval to own additional Charging Hubs, then it will discontinue seeking similar awards, which could limit competitive federal funds in Michigan (Peterson, 4T 740-41, 801-802).

The PFD further states:

> Further, DTE has stated that it does not want to compete with third-party developers of charging hubs in the long-term. Given this statement, this PFD agrees with MEIU's suggestion that the Commission should direct DTE to develop a preliminary plan in its next rate case to address the utility's plan for the ultimate disposition of the constructed charging hubs in the long term. [PFD, p 664.]

The Company disagrees because the charging hubs have not even been built yet. Although there are good reasons for this, and it should not stand in the way of approving a third hub (as discussed above), this makes the PFD's recommendation to "direct DTE to develop a preliminary plan in its next rate case to address the utility's [ultimate] plan" premature, founded upon speculation as to optimal outcomes, and without regulatory precedent.

iv. Community Chargers and School Bus Chargers

The Company proposes two new pilot elements: Community Chargers and School Bus Chargers (Peterson, 4T 741; Exhibit A-12, Schedule B5.9.1 summarizes how they meet the

requirements of the February 4, 2021 Order in Case No. U-20645). The Company agrees with the PFD's recommendation to approve the School Bus Chargers pilot (PFD, p 675), but notes that accommodating MNSC and MEIU's suggestions may require further cost recovery. That further cost recovery would involve the transfer of the amount of capital expense the Company would otherwise deploy to a regulatory asset for recovery.

Under Community Chargers, DTE Electric would build, own, operate, and maintain approximately 250-360 Level 2 chargers in public parking locations, including curbside installations such as utility pole-mounted and streetlight-mounted chargers. This element is needed for three primary reasons: (1) there are not enough Level 2 chargers in DTE Electric's service territory; (2) there is a discrepancy in charging access depending on where DTE Electric customers live; and (3) many multi-unit dwelling (MUD) residents are unable to capitalize on the $1 eGallon equivalent of charging off-peak on a TOD rate. The Company intends to utilize the existing D1.9 tariff structure to assess a TOD-based usage fee to drivers, which would be collected through the charger. The Company seeks key learnings including the utilization, performance, and cost-effectiveness of pole-mounted chargers. Costs are projected to be $3.6 million for the projected test year. The Company requests capital treatment, consistent with other Company-owned chargers approved in Case No. U-20836 (Peterson, 4T 742-49; Exhibit A-12, Schedule B5.9, page 4, line 7, column (f)). The PFD instead recommended disapproval, stating:

> This PFD finds the proposed pilot intriguing, but this PFD ultimately agrees with Staff that the pilot warrants disapproval as it would potentially set the stage for large-scale utility ownership of charging infrastructure that could shift risks to ratepayers and compete with non-utility charging market participants. The proposed pilot is partially aimed at areas currently underserved by charging solutions with DTE asserting that it would commit at least 40% of funding to rural and disadvantaged areas. However, it is not clear that such areas will remain underserved in the future to such an extent that would warrant utility ownership of charging infrastructure.
>
> MEIU suggested multiple changes to the pilot that would partially allay concerns about utility ownership, and MEIU also persuasively rebutted several of DTE's

> arguments in opposition to MEIU's suggestions. However, giving landowners the choice to own and operate charging stations themselves, seek out third-party vendors, or allow DTE to own and operate the stations primarily resolves concerns about competing with market participants; it does not meaningfully resolve the potential problem of large-scale utility ownership of charging infrastructure. [PFD, pp 671-72.]

The Company maintains that the pilot should be approved. In addition to the discussion above, the PFD's indicated apprehensions and other musings are speculative, [132] and the overall suggestion that the pilot could "potentially set the stage" for a "potential problem" is particularly overstated and inappropriate in this context of starting a pilot. The Company further notes that MEIU witness Sherman made five recommendations regarding Community Chargers. The Company does not take issue with recommendation 5 (i.e., all charging stations are required to have a NRTL certification and be networked), but otherwise disagrees because the proposed modifications would substantially alter the Company's proposal and are otherwise inappropriate, as further discussed on the record (Peterson, 4T 797-98). The Company maintains that this element is needed, and although opinions on Company ownership of charging infrastructure vary, the Company is not aware of any substantial effort to provide the type of community charging service the Company proposes (Peterson, 4T 743-47, 796-97).

v. Updated Benefit-Cost Analysis (BCA) and Transportation Electrification Plan (TEP)

Total Charging Forward Expansion costs are projected to be $18.6 million in the 23 months ending November 30, 2023 (consistent with the approval of the Expansion in Case No. U-20836), and $33.2 million in the projected test year (Peterson, 4T 755; Exhibit A-12, Schedule B5.9, p 4,

[132] *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).

line 24, columns (e) and (f)). Based on projected EV sales, and EVs putting downward pressure on overall rates, the Company estimates net present value (NPV) system benefits of $51.3 million to $59.9 million for the projected test period (Peterson, 4T 758). Reducing this amount for EV sales not influenced by DTE Electric, and participant-funded elements, the overall NPV net benefits to DTE Electric customers for the projected test period are estimated to be $2.1 million to $6.4 million. The Company plans a broader benefit-cost analysis (BCA) framework for future programs as part of its Transportation Electrification Plan (TEP). (Peterson, 4T 760).

The PFD essentially found that the Company's BCA was sufficient for purposes of this case and disagreed with various divergent positions asserted by other parties (PFD, pp 690-91). The PFD then states:

> Given the deficiencies and challenges identified above, this PFD recommends that DTE Staff, and interested parties work together to develop a more comprehensive BCA framework that is aligned with the Commission's guidance provided in this case. . . . Part of DTE's process for developing the TEP involves soliciting stakeholder input, and this PFD suggests that the BCA should be one of the topics that stakeholders should robustly discuss with the utility as part of the TEP in order to attempt to find significant common ground in developing a more rigorous framework for a BCA of the Charging Forward programs. [PFD, pp 691-92.]

The Company further explained that MNSC and MEIU's various recommendations for what the Commission should require the Company's TEP to contain or consider are premature. The Company will engage stakeholders before publishing the TEP by year end to inform final program design. This also addresses EVgo's recommendation that the Commission direct the Company to host at least one stakeholder meeting (Peterson, 4T 805-806). The PFD agreed that the suggestions were premature (PFD, p 696), but further stated:

> DTE has committed to hold at least one stakeholder meeting; however, it is not entirely clear whether DTE intends to hold additional meetings; further, it is not clear from DTE's testimony whether the utility will seek collaborative input or whether it will simply present a finished plan for stakeholders to merely comment upon. This PFD is concerned that a single meeting held only after DTE has already

> fully developed the TEP may not foster meaningful collaboration between the utility and stakeholders. Accordingly, this PFD recommends that the Commission request that DTE hold at least two stakeholder meetings and to do so as early in the development of the TEP as is reasonably practicable. . . . In other words, this PFD recommends that the Commission should direct the utility to hold at least two stakeholder meetings on the TEP and to use said meetings as a vehicle to resolve as many disputes about the scope and nature of the TEP as possible before the TEP is raised in a rate case [PFD, pp 698-99. Footnote omitted.]

The Company takes the discussion in the PFD as agreement with the Company and thus no exception appears warranted. Furthermore, the Company expects continuing dialogue on the matter and thus the limited concerns identified in the PFD do not merit any specific Commission action.

XI. FORD MIGREENPOWER (MIGP) CONTRACT

The Company requests to not apply Michigan Administrative Code R 460.2031 or the Commission's prior special contract concerns to the Ford MIGP contract (See generally, DTE Electric's Initial Brief, pp 261-63). The PFD instead opines:

> No one disputes that DTE is not asking to recover costs associated with this contract in this rate case, and seemingly has no plans to do so over the 35-year term of the contract. Nonetheless, this PFD finds that Staff's recommendation regarding the classification of the contract is reasonable and consistent with the common understanding of special contract. The PFD therefore declines to recommend that the Commission find that the Ford MIGreenPower contract is not a special contract. [PFD, p 703.]

The Company agrees that there is no substantive reason to deny the Company's request, but otherwise disagrees, first noting that it is not asking the Commission to find that contract is not a special contract as the PFD suggests. Instead, the PFD reflects on the same page, the Company "argues that this contract should not be treated like the contracts the Commission approved in Case No. U-10646 . . . ." (PFD, p 703). Unlike the 1995 special contracts, the Ford MIGP contract (1) does not offer a discount to any established tariff; (2) uses the same methodology as an established

tariff (Rider 17) to calculate revenue required from the customer; and (3) the revenues and costs do not currently flow through current or projected base rates. Therefore, the Commission should recognize that its directives and concerns about special contracts do not apply here (Crozier, 5T 2197).

More specifically, in accordance with the settlement of the Company's Renewable Energy plan (REP) and Voluntary Green Pricing (VGP) cases (Case Nos. U-20713 and U-20851 respectively), DTE Electric filed an application requesting approval of a customer-requested special contract between DTE Electric and Ford Motor Company (Ford). The Commission granted the approval, and further ordered: "DTE Electric Company, in its subsequent general rate cases, shall file evidence demonstrating that the special contract with Ford Motor Company complies with the Commission's previous directives regarding special contracts and Mich Admin Code, R 460.2031." (Case No. U-21825, 12/21/2022 Order, p 6).

The cited rule concerns filing special contracts and is not relevant here. The Commission further explained that it had a concern about discounted special contracts being subsidized by other customers:

> Speaking to cost allocation, the Commission found in that March 23 [1995 Order in Case No. U-10646] that, "unless [The] Detroit Edison [Company] can make a compelling showing why a different ratemaking treatment is justified, the Commission will not permit Detroit Edison to reallocate the costs of serving contract customers to other ratepayer classes." March 23 order, p. 21. [Case No. U-21285 Order dated December 12, 2022, p. 4, n. 2.]

The special contracts in Case No. U-10646 provided discounts to General Motors, Ford, and Chrysler (now Stellantis) in exchange for their commitment to continue as customers. In contrast, the Ford MIGP does not provide a discount to the Company's Rider 17 tariff, which is available to all DTE Electric customers (Crozier, 5T 2193-94). Therefore, there is no discount to even consider reallocating among customers.

There are some differences between the Ford MIGP contract and the Rider 17 tariff (for example, the Ford contract is a 35-year contract, but a Rider 17 contract can be as short as five years), but customers benefit from these differences. Ford's obligation to a longer contract term, restricted termination period, and termination fees designed to mitigate any impact to other customers provides DTE Electric with an enhanced certainty of revenue recovery for the costs of the underlying assets compared to their Rider 17 customers (Crozier, 5T 2194-95).

The Ford MIGP contract will not affect cost allocation or base rates in this case. The revenues and costs for this contract, as with the Rider 17 revenue and costs, are all reconciled in the Company's REP filings (Crozier, 5T 2195-96).

The Ford MIGP contract will not be subsidized by other customers. Ford will pay a levelized subscription fee designed to recover the revenue requirements for the final costs of the solar projects over the life of the contract. This is a well-established methodology that is also used to calculate other customers' subscription fees pursuant to Rider 17 (Crozier, 5T 2196).

It is true that Staff took a strict position by stating, for example that "[t]he fact that the FORD MIPG contract *is required at all* means that it is a special contract." (*Id*., p 150) (Staff's Initial Brief, pp 149-51. Emphasis in original). As indicated above, this limited position may be literally true, but it neglects to address what the Company is requesting and the reasons supporting that request. As indicated above, the Ford MIGP contract has similar terms as Rider17, which is available to all customers. Any difference in the terms does not harm or disadvantage the broader DTE Electric customer base. When the Commission's directives were issued in Case No. U-10464, the contracts did not mirror an approved tariff like the Ford MIGP contract does. Therefore, the MIGP contract merits different treatment as the Company requests (Crozier, 5T 2232-33).

In summary, although the Ford MIGP contract is arguably a "special contract," it should not be treated like the special contracts that the Commission approved in Case No. U-10646. Unlike the 1995 special contracts, the Ford MIGP contract (1) does not offer a discount to any established tariff; (2) uses the same methodology as an established tariff (Rider 17) to calculate revenue required from the customer; and (3) the revenues and costs do not currently flow through current or projected base rates. Therefore, the Commission should recognize that its directives and concerns about special contracts do not apply here (Crozier, 5T 2197).

XII. INFRASTRUCTURE RECOVERY MECHANISM (IRM)

The Company proposes a Distribution IRM to facilitate the distribution system upgrades that must be made to maintain and improve safety and reliability (See generally, DTE Electric's Initial Brief, pp 229-37). The PFD recommends that the IRM should be rejected as premature, explaining in part:

> In part based on the company's failure to support the costs proposed for recovery in this case, this PFD recommends that DTE's IRM proposal be rejected. Should DTE wish to pursue an IRM, this PFD recommends that the Commission require DTE to file a stand-alone case, in which its DGP could be evaluated, with a goal of determining which distribution system investments would be well-suited to recovery through such a mechanism. This would provide parties an opportunity to review and evaluate the DGP. [PFD, pp 190-91.]
>
> * * *
>
> This PFD recommends the Commission reject the proposed IRM at this time. As discussed above, DTE failed to establish that its DGP, with its black-box GPM, adequately paces or prioritizes investments to protect ratepayers from potentially hundreds of millions or billions of dollars in excess capital spending, to actually promote improved reliability and improved grid equity, and to retain measures of affordability. For these and other reasons, the proposal is premature. [PFD, p 741.]

The Company incorporates its discussions above explaining that the PFD's criticisms of the DGP and GPM are inaccurate and overstated, and disagreeing to the extent that the PFD suggests

a stand-alone DGP case (See generally, section IV. A. 10). The PFD's IRM discussion omits any substantive analysis regarding the proposed IRM. It is important to consider what the Company actually proposes and the reasons supporting it, as discussed below.

As a preliminary matter, the PFD's suggestion that the proposed IRM is "premature" is inconsistent with prior proceedings and guidance from the Commission. For example, in Case No. U-20162, the Company proposed an IRM to recover the incremental revenue requirement associated with certain distribution, fossil generation and nuclear generation capital expenditures. The Commission did not adopt that proposal, but stated:

> The Commission is receptive to considering an IRM with the proper oversight, legal structure, and performance-based regulation framework including customer protections. [Case No. U-20162 Order dated May 2, 2019, p. 117.]

The Company did not propose an IRM in its last rate case, but the Commission indicated that it might consider one in the context of discussing strategic capital investments in the Company's distribution system:

> The Commission cannot stress enough its expectation that DTE Electric will invest the amounts approved for strategic capital investments and not shift them to other categories such as emergent replacement and other reactive spending. As such, **the Commission may be willing to consider a long-term investment recovery mechanism (similar to the Infrastructure Recovery Mechanism for the gas Main Renewal Program first approved in the April 16, 2013 order in Case No. U-16999) to ensure that the spending included in rates for strategic capital improvements—including the ultimate conversion of DTE Electric's distribution grid—is spent for these purposes, and to provide greater long-term certainty on recovery of reasonable and prudent costs related to these strategic distribution grid investments**. The Commission expects that DTE Electric will include in any such proposal a full description of costs and benefits, as well as associated timelines. [Case No. U-20836 Order dated November 18, 2022, p. 77. Emphasis added.]

Accordingly, the Company now proposes a Distribution IRM that is similar to the DTE Gas IRM and is focused on strategic capital programs. Based on the Commission's guidance, the Company broadly looked for programs critical to customer safety, reliability, and/or resilience, and

specifically identified programs supporting the ultimate conversion of the Company's distribution grid. (Foley, 2T 50, 54, 62). The Company proposes to include five programs in the initial Distribution IRM:

1. Circuit Conversions, including both City of Detroit Infrastructure (CODI) and non-CODI conversions (Foley, 2T 63-64; Deol, 2T 190-92; Exhibit A-23, Schedule M5);

2. Sub-transmission Redesign & Rebuild (Foley, 2T 63-64; Deol, 2T 190-93; Exhibit A-23, Schedule M5);

3. Breaker Replacement (Foley, 2T 64-64; Elliott Andahazy, 3T 500-504; Exhibit A-23, Schedule M4);

4. Underground Residential Distribution (URD) Replacement (Foley, 2T 63-64; Elliott Andahazy, 3T 500-504; Exhibit A-23, Schedule M4); and

5. 4.8 kV Circuit Automation (Foley, 2T 63-64; Hill, 5T 2732-34).

Again, the proposed Distribution IRM is also largely based on the DTE Gas IRM that the Commission referenced in Case No. U-20836 (Foley, 2T 59). The PFD dismisses this by stating that the "PFD perceives that the success of the DTE Gas IRP [*sic* IRM] related to a general recognition that the work to be performed would be performed reasonably well and constituently," in suggested contrast to this case (PFD, pp 742-43). The PFD cites nothing to support its indicated perception, which further neglects that there was substantial controversy about the existence and scope of the DTE Gas IRM. Ultimately, in those proceedings (and continuing here as indicated by the Commission's reference to the DTE Gas IRM), various anti-IRM arguments were found unpersuasive.[133]

[133] The DTE Gas IRM began when the Commission approved DTE Gas's recovery of 2013-17 IRM capital investments for the Meter Move Out Program (MMO), the Main Renewal Program (MRP), and incremental MRP and Pipeline Integrity (PI) investments (April 16, 2016 Order in Case No. U-16999). The Court of Appeals affirmed this decision. *In re Application of Michigan Consolidated Gas Company to increase rates*, unpublished opinion per curiam of the Court of Appeals, issued December 11, 2014 (Docket Nos. 316141 and 316263) (2014 WL 7003882). The Commission approved additional infrastructure investments as part of an expanded IRM for 2016 and 2017 (November 23, 2015 Opinion and Order in Case No. U-17701), and authorized additional spending of $102.1 million in 2016, and $127.6

The PFD also suggests that the proposed IRM would allow the Company to commence and continue projects without having to justify them. This is not the case, as the record establishes that the proposed IRM would provide four key benefits in this context. First, the Distribution IRM would provide certainty of investment in key distribution capital programs focused on customer safety, customer reliability, and the integration of increasing levels of Electric Vehicles (EVs) and other Distributed Energy Resources (DERs). It also directly responds to the Commission's expectation that "DTE Electric will invest the amounts approved for strategic capital improvements and not shift them to other categories" (Case No. U-20836 Order dated November 18, 2022, pp. 76-77, further quoted above). Under the proposal, the Commission would approve both the amount of the investment and the specific programs. The Company would not be able to recover its capital costs between rate cases for programs not covered by the IRM, or if the Company shifts investment amounts among programs. Any underinvestment in the programs associated with the IRM would be returned to customers, providing the appropriate customer protections requested by the Commission (Foley, 2T 55-56, 61-62).

Second, the Distribution IRM would provide greater transparency into both the Company's investment plans and its execution of those plans. The Company proposes an annual "IRM Planning Process" that would provide Staff with greater detail about the Company's investment plans for the upcoming year. The Company also proposes an annual "IRM Reconciliation Process" that would provide information about the Company's execution of its investment plan, including projects completed compared to what was planned, and actual project costs compared to what was planned

million in 2017 through 2021 on IRM programs, as well as flexibility in spending among the programs (December 9, 2016 Order in Case No. U-17999, pp 52, 67). In DTE Gas's next rate case, the Commission approved additional capital expenditures, including funding to further expand and accelerate infrastructure replacement (September 13, 2018 Order in Case No. U-18999, pp 21, 26, 32-33). Most recently, the Commission again approved additional funding for the DTE Gas IRM and rejected anti-IRM arguments (December 9, 2021 Order in Case No. U-20940, p 172).

(Foley, 2T 55-57). Both processes are modeled after the DTE Gas IRM processes (Foley, 2T 59). The Planning Process would (1) provide greater transparency related to the Company's plans for its IRM investments, and (2) solicit feedback from Staff regarding the Company's plans (Foley, 2T 73-76). The Reconciliation Process would (1) provide greater transparency into the Company's execution of its IRM investment plans, and (2) reconcile actual investment and plant-in-service to planned investment and plant-in-service so that any over-recovery associated with program under-investment can be returned to customers (Foley, 2T 76-77).

Third, the Distribution IRM would provide Staff with additional opportunities to review and provide input on the Company's investment plans as part of the proposed IRM Planning Process (Foley, 2T 55, 57).

Fourth, the Distribution IRM would result in increased accountability for the Company to fully execute its strategic investments. As part of the IRM Reconciliation Process, the Company proposes to begin reporting new program execution metrics that are designed to specifically address the Company's execution of its investment plans (Foley, 2T 54, 57). The Company emphasizes that the amount of capital that could be recovered for any program through the IRM would not be allowed to exceed the program-specific maximum authorized by the Commission for IRM treatment as proposed in Exhibit A-33, Schedule X1 (Foley, 2T 68, 70). If the Company were to invest more in a program than the level authorized for that program in the IRM, then the Company could seek to recover the additional investment through base rates in a future rate case. If the Company were to invest less in a program than the level authorized for that program, then the over-recovery associated with that under-investment would be deferred as a regulatory liability until a subsequent rate case. At that point, any IRM over-recovery would be returned to customers through a time-bound credit, with short-term interest. The credit would be allocated to the Company's

various classes of customers and calculated in the same manner as the IRM surcharges (Foley, 2T 68, 71-72; Uzenski, 5T 15615T 1503). Mr. Vangilder also prepared an illustrative example (5T 2599-2600; Exhibit A-33, Schedule X5).

In addition to these immediate benefits, another longer-term objective is to extend the time between rate cases, reducing administrative burdens and costs for all parties involved (Foley, 2T 57-58).

The PFD further opined that the Company should wait to propose an IRM that incorporates Performance-Based Ratemaking (PBR), stating that "it would be premature to approve an IRM absent any PBR framework given the pendency of the workgroup and forthcoming guidance from the Commission" (PFD, p 742). The Company disagrees because the Commission's IRM guidance (quoted above) did not indicate that the Company should wait. The Commission also recently indicated that it would launch a Financial Incentives and Disincentives workgroup (Case No. U-21400 Order dated April 24, 2023). The Company sees no reason to wait while the workgroup proceeds. Delaying the IRM would also delay the IRM's benefits, as discussed above (Foley, 2T 94-95, 161, 172). [134]

Staff's Initial Brief, pp 146-49 recommends that the Commission approve the IRM, explaining in part that "Staff supports the Company's Distribution IRM proposal, as it will help ensure continued investment in DTE Electric's distribution system" (*Id*., pp 148-49). Staff further proposed the following modifications in response to the Company's proposal that it would submit

[134] On the general topic of PBR, the Company agrees with the PFD's recommended rejection of ABATE's proposed earnings sharing mechanism (ESM) and the AG's proposed Service Improvement Incentive Mechanism (SIIM). (PFD, pp 747, 751). Although the Company is not aggrieved by these specific decisions, the Company notes that some of the PFD's commentary is unfounded and unjustified (e.g., PFD at p 747-48), and reserves all rights here and in future proceedings.

an IRM Investment Plan to Staff no later than two months prior to the start of each IRM Plan Year (Foley, 2T 74):

1. The Company should submit the IRM Investment Plan no later than four months prior to the start of each IRM Plan Year, not two months.
2. The Company should submit a copy of this plan to all intervening parties in the Company's most recently filed rate case, not just to Staff.
3. The Company should schedule and provide a forum for Staff and the intervening parties to raise any questions or concerns that they have before execution of the plan begins. The forum should occur no later than two months before the start of the IRM Plan Year. [Staff Initial Brief, p 149.]

In response to Staff's proposed timing-related suggestions set forth in its Initial Brief, and in anticipation of the IRM being approved, the Company has begun developing the 2024 IRM investment plan with the goal to meet the deadline of October 31, 2023 as proposed in the instant case. As such, while the Company could implement Staff's suggested approach in future years (with the timing modification discussed below), the timing of Staff's proposal is not feasible for the submission of the 2024 plan. The Company intends to meet with Staff to solicit feedback and ensure alignment prior to the final 2024 plan being submitted.

Beginning with the 2025 IRM investment plan (to be submitted in 2024), the Company proposes to submit the draft IRM investment plans as well as conducting a forum or technical conference on or near three months ahead of the start of the planning year (versus Staff's proposed four months). The Company proposes three months in order to sync up with the end of storm season and allow time to evaluate recent reliability and productivity performance as part of finalizing the IRM investment plan for the next year. After considering stakeholder feedback, the Company would

submit final IRM investment plans no later than two months before the start of the planning year. This process would support adequate communication to interested parties as well as the opportunity for interested parties to provide feedback on the Company's proposed IRM investments.

The PFD concludes its IRM section with commentary about a potential future proceeding (PFD, p 743). The comments are speculative and/or moot so Company declines to digress into them, but reserves all rights for and in future proceedings.

In summary, the Company's proposed Distribution IRM is well designed and fully supported. Therefore, it should be approved along with the Company's proposed IRM surcharges included in Exhibit A-33, Schedule X7.[135]

XIII. COST ALLOCATION

A. State Reliability Mechanism (SRM) Capacity Charge

DTE Electric's Initial Brief, pp 269-73, discussed the Company's capacity charge revenue requirement ($1.395 billion, as reflected on Exhibit A-26, Schedule P3, Line 27). Energy Michigan witness Zakem recommended that "any expenses other than fuel should be removed from the 'net of projected fuel' calculation" (Zakem, 6T 4083. Emphasis omitted). The Company disagrees for a number of reasons that Mr. Burgdorf explained;

> The Commission allowed the Company to include "Fuel-Related Costs' in Case No. U-20561 as these costs are all incurred as a result of the production of energy from the Company's generation resources. The Company continues to justify appropriate costs that should be included in the Fuel-Related Costs (e.g. emission allowance costs that are directly associated with the fuel and required by the Environmental Protection Agency) in the instant case to ensure all customers are treated fairly. The Commission has also deemed these Fuel-Related Costs as recoverable in the PSCR cases. If any of these costs were to be excluded from the

[135] If the proposed IRM is not approved, then the Company requests that the capital expenditures included in the IRM through the projected test year be added back to the forecasted financial statements for recovery in base rates, as discussed by Ms. Uzenski (5T 1560-61). The adjusted revenue deficiency would be $583 million, which is a $3.4 million increase to the revised revenue deficiency reflected in Attachments A and B to DTE Electric's Reply Brief.

> Fuel-Related Costs category, then the Company's PSCR customers would be subsidizing customers paying the SRM Capacity Charge. Furthermore, the energy sales revenue would not be possible without incurring the Fuel-Related Costs necessary to produce the power to enable the sales, therefore, anyone receiving the revenue benefit should bear the associated cost. [Burgdorf, 5T 2076.]

The PFD instead agreed with Energy Michigan, stating:

> This PFD agrees with Energy Michigan that the plain language of MCL 460.6w(3)(b) refers only to "projected fuel costs" and not "fuel-related costs" such that the inclusion of fuel-related costs does not comport with the statute's plain language. Accordingly, this PFD recommends removal of the emissions allowances and chemical costs that DTE included as "fuel-related costs." This PFD notes that this conclusion appears consistent with DTE's previous rate case, Case No. U-20836, in which this issue was raised by Energy Michigan and in which the ALJ and Commission rejected the same counterarguments that DTE offers again in this case, including the utility's misplaced reliance on Case No. U-20561. [PFD, pp 770-71. Footnote omitted.]

The Company disagrees. In addition to the discussion above, the PFD's reliance on Case No. U-20836 is inapt since the issue there concerned MISO Schedule 17 administrative costs. Staff's Initial Brief, p 109, also supported the Company's capacity revenue requirement methodology as "consistent with the Commission's Order in Case No. U-20836," and recommended that the Commission approve it here. Staff's Reply Brief, p 10, further observed that emission allowances and chemical costs were included in the original capacity charge revenue requirement in Case No. U-18248.

The Company further submits that "fuel costs" has acquired a "peculiar and appropriate meaning" in this context and through PSCR proceedings as discussed above. MCL 8.3a. See also, *In re Application of Detroit Edison Co*, 483 Mich 993 (2009) (holding that the Commission did not err in permitting DTE Electric to recover transmission costs through its PSCR clause because "booked costs of purchased and net interchanged power transactions" had acquired a "peculiar and appropriate" meaning in the regulation of electric utilities to include transmission costs charged by third parties). Similarly, as a matter of general understanding and common sense, the cost of fuel is

the full cost that enables the fuel to be used as fuel because otherwise it would not be fuel (e.g., the fuel that people pump into their cars at gas stations includes additives in addition to just gasoline).

XIV. RATE DESIGN AND TARIFF ISSUES

A. Distribution Cost Allocation Implementation

The Staff proposed a change to distribution cost allocation and an associated implementation method (7T 4602, 7T 4458-4459). The Company took no position on the change to allocation; however, the Company did describe that the Staff's proposed "IDACS" implementation mechanism was concerning, and the Company would not be able to implement such a proposal concurrent with rates in the instant case, in addition to concerns about customer understanding and cost (Willis, 5T 3221-22). The PFD generally agreed and recommended the Company's secondary suggestion to implement the allocation change over two cases in lieu of a separate set of surcharges and credits:

> The PFD also recommends that the Commission include half of the proposed secondary cost shift in this rate case and the remainder in DTE's next rate case. The PFD agrees with Staff that neither timing nor cost are (or should be) an issue with the IDACS; however, customer confusion could result from the implementation of this method, and the same result can ultimately be accomplished by simply splitting the cost shift over two rate cases. [PFD, p 766-767.]

However, the Company takes exception to the PFD on the topic of "IDACS" implementation. While both the PFD and parties believe the Company could implement such a mechanism within several days, as described by the Company, this is not possible (Willis, 5T 3221).

B. Rate D1.13, the Residential "Overnight Savers TOD" Tariff

The PFD (at p 784) has a caption including this topic, but does not discuss it or offer a recommendation. This presumably is just an oversight because there apparently is no dispute. For

completeness and the Commission's convenience, the Company discusses its proposal to establish Rate Schedule D1.13 (Overnight Savers TOD).

The Company proposes to establish Rate Schedule D1.13 (Overnight Savers TOD), which has four key features: (1) it has three pricing periods; (2) it varies distribution, power supply capacity, and power supply non-capacity rates; (3) it is a voluntary rate that will be offered to residential customers; and (4) it is a whole-home rate that does not require additional metering (Willis, 4T 3189, 3215).

The Overnight Savers rate is an appropriate addition to the portfolio of rates that is available to customers because it is a cost-aligned option for low overnight pricing, it offers additional optionality to customers, and it is a more broadly accessible rate for customers seeking low overnight pricing, such as those who own or lease electric vehicles (EVs). The success of Rate Schedule D1.9 (the Company's supplemental EV charging rate) established that customers desire low overnight rates for EV charging (and potentially other things). The Company's primary offering that delivers on this desire without critical peak pricing requires a second meter, which might discourage or preclude customers from taking service. Customers that cannot leverage D1.9 but could use D1.13 Overnight Savers include renters, customers in multifamily dwellings, and customers who are interested in EV ownership (and particularly those leasing an EV) but do not want to make the cost commitment of new wiring and a second meter (Willis, 5T 3189-90, 3192, 3194). Overnight Savers is intended in part as a successor to D1.9, and the Company expects that a relatively high proportion of Overnight Savers customers will have EVs (Willis, 5T 3197-98).

Overnight Savers has three pricing periods: (1) On-Peak (3:00pm – 7:00pm weekdays); (2) Super Off-Peak (1:00am – 7:00am all days); and (3) Off-Peak (all other hours). The on-peak pricing period is designed to be consistent with Rate Schedule D1.11 (default time-of-use rate). The super

off-peak period is designed to align with the Company's lowest load hours from both a system and residential customer perspective. This period is a critical part of the proposal because it is a rate option for highly-engaged customers who have the ability and desire to shift load into overnight hours, or add load in overnight hours (Willis, 5T 3191-92).

Overnight Savers offers cost-aligned pricing for all load on one rate, which balances lower overnight (super off-peak) pricing with higher daytime and peak pricing. The resulting rate is designed to be revenue neutral to D1.11. Thus, the rate maintains overall cost alignment and revenue neutrality, while offering low overnight pricing (Willis, 5T 3185, 3193) .

The proposed design varies pricing based on observable market and system characteristics. Power supply capacity and non-capacity prices vary depending on the ratio of the LMPs across the pricing windows, which is the same methodology used for Rate Schedule D1.11, and conveys to customers the economics of power supply and when costs are higher. Distribution prices vary depending on average residential substation loading, which is a measure of relative grid demand (Willis, 5T 3190, 3194-97).

The Company anticipates that the Rate Schedule D1.13 will drive changes in usage patterns compared to D1.11 due to a relatively high proportion of customers charging EVs during super off-peak hours. The present assumption is that super off-peak usage would increase 5%, with those sales proportionally reduced from the off-peak and on-peak periods. Actual usage patterns might differ, however, and there is some uncertainty due to the lack of a comparable rate offering. Therefore, the Company proposes to limit D1.13 enrollments to 10,000 customers. Assuming that Rate Schedule D1.13 is approved, the Company plans to have it become effective during the projected test year upon system implementation (Willis, 5T 3197-98).

Therefore, the Company's proposed Rate Schedule D1.13 (Residential Service Rate – Overnight savers TOD) should be approved.

XV. RATE SCHEDULE D1.6 TRANSITION AND CLOSURE

The Company proposes to change the Low-Income Assistance (LIA) program by eliminating Rate Schedule D1.6 (which offers qualifying low-income customers a $40 per month credit on their bills) and transitioning all D1.6 customers to D1.11. The Company also proposes to expand the availability of the LIA credit to all residential base rates, including D1, D1.11, D1.2, D1.8, D2, and the proposed D1.13. This change will have no substantive impact on the credit, and will bring the LIA availability in line with how the electric Residential Income Assistance (RIA) program is managed (Griffie, 5T 2096; Willis, 5T 3200-3203, 3215). The Company also proposes to expand its senior provision (now available on only rate schedules D1 and D1.11) so that it is available to all residential base rates. This would support customer flexibility and optionality. After the change, customers could utilize the credit on D1, D1.2, D1.8, D1.11, D2, and the proposed D1.13 (Willis, 5T 3203, 3215).

The Company essentially agrees with Staff's recommendations regarding the timing for filing D1.6 and D1.13 tariffs (Isakson, 7T 4482), and believes that it is prudent to (1) file the tariffs on the typical 30-day post-order timeline, and (2) with additional language noting their effective dates as no later than November 30, 2024 (Willis, 5T 3225).

The PFD generally agreed, but recommended further study instead of moving forward, stating:

> This PFD generally finds DTE's and Staff's contention that retirement of Rate D1.6, coupled with the transition of customers to rate D1.11 is a reasonable course. As Mr. Willis explained, the company's proposal increases the availability of rate options for low-income customers, which could mitigate any adverse impacts from the change to TOU rates. Further, the PFD agrees that the potential benefits and

> costs of TOU rates versus a flat rate have been discussed extensively in past cases, and the Commission has determined that TOU pricing is reasonable and appropriate for residential customers. However, DAAO is not asking for a permanent ban on switching to TOU pricing, but is seeking an analysis of the potential benefits. This PFD concludes that an additional one-year delay is not unreasonable, and has the potential to avoid unintended consequences. Thus, this PFD recommends that the Commission require the analysis called for by DAAO and revisit this issue in DTE's next rate case. [PFD, p 789.]

The Company agrees that its proposal is reasonable, but disagrees with the PFD's inconsistent recommendation to not move forward. The benefits of the Company's proposal are clearly established on this record and the benefits of TOU pricing have been addressed extensively in past cases—as even the PFD recognized. There is no sound basis to conduct a study to look for some potential reason to depart from the Commission's TOU direction and instead not move toward TOU rates as the PFD suggests. Staff similarly disagreed with DAAO and recommended that the Commission "reject DAAO's proposals and approve the Company's elimination of Rate D1.6 and addition of the special low-income assistance credit to the remaining residential rate schedule tariffs" (Staff Initial Brief, pp 120, 133).

It is also important to keep in mind that DAAO's various suggestions of a need for further study were unfounded and disproven. More specifically, and in addition to the discussion above, DAAO witness Koeppel did not support the Company's proposal to transition D1.6 customers to D1.11, and expand the availability of the low-income assistance credit, asserting that "the forced conversion of LMI customers onto the D1.11 TOD rates raises equity and customer education concerns" (6T 4002). There is no sound basis for Mr. Koeppel's indicated concerns and Mr. Koeppel offered no evidence for his assertions. A customer receiving (or who desires to receive) the credit must take service on Rate D1.6 (regardless of whether the customer wants that rate schedule) and presently has no alternative option. The Company's proposal to open the LIA credit to all base rates provides customers options and flexibility. Mr. Koeppel does the opposite by

essentially proposing that customers be forced to stay on (or move to) Rate D1.6 as a condition of receiving the credit (Willis, 5T 3245-47).

The Company's proposal to close rate D1.6 is also appropriate because the Commission has made it clear that the Company should be oriented toward time-of-use rates for residential customers. Rate D1.6 customers are the only customers (apart from those without transmitting meters and customers on Rate Schedule D2 which has been closed to new customers since 2015) who remain on the legacy inverted block rate. Rate D1.6 was established as the vehicle for the LIA credit simply because that rate design mimicked the default (D1) residential rate at the time. The default rate is now time-of-use, so that is the most appropriate rate design going forward (Willis, 5T 3246-47).

Despite all of this (including the PFD's implicit rejection of all of Mr. Koeppel's substantive arguments), the PFD was persuaded by Mr. Koeppel's further recommendation for an "analysis from DTE on the impacts of TOU conversion on LMI households" (6T 4022). In addition to the discussion above, the Company disagrees because the recommendation disregards the extensive record of D1.11 in prior cases, and the fact that it is the default rate for nearly 2 million customers. The study would also be onerous to conduct, and provide little, if any, determinative value (Willis, 5T 3247).[136]

[136] The suggestion also implicates the AG's concerns regarding the ever-expanding volume of information in general rate case proceedings (AG Initial Brief p. 14 *"…testimony is often wordy but does not get to the essence of the issues that intervenors and the Commission Staff are interested in…Some of the exhibits have become too lengthy and full of unnecessary minutia…*). Repeated demands for more and more detailed information from more and more parties have predictable consequences. It would be reasonable to consider the likely marginal benefit and diminishing returns associated with additional production of further detail, study, and analysis.

XVI. CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC) AND STANDARD ALLOWANCE TABLE

The Commission previously agreed with this ALJ to continue discussion of CIAC recommendations through the CIAC workgroup (November 18, 2022 Order in Case No. U-20836, pp. 475-76). MNSC proposed that the Commission should refuse to update the CIAC Standard Allowance table until the Company has updated the per-foot costs in Section C6 of the Company's rate book, which are chargeable to individual customers based on work performed by the Company for the customer. The PFD agreed, stating:

> This PFD agrees with MNSC that the Commission should decline to update Section C6.2, at least at this time. Further, the PFD recommends that for its next electric rate case, the Commission order DTE to provide detailed information on the current per-foot costs for line extensions along with updated CIAC tariffs that include the updated costs. [PFD, p 793.]

The Company disagrees because the per-foot costs are unrelated to the Standard Allowance table. MNSC witness Mr. Ozar conflated two different things. There are two distinct elements when determining a customer's actual CIAC: (1) the cost of the work, however determined, and (2) any allowances provided to the customer based on the margin contribution of the new or increased load. The per-foot costs are part of (1) because they are a construction cost. The Standard Allowance table is part of (2) because it is based on the margin contribution of a customer on a given rate schedule and greater than 1000 kW of load. It would be inappropriate to hold the table in limbo, and unduly impact the Company's largest customers, contingent on the outcome of an unrelated matter. The Company underscores that tariffed per foot construction costs are not an input in the standard allowance table and linking them is inappropriate. The Company also believes that the

per-foot costs in its tariff remain appropriate.[137] Therefore, the Commission should approve the updates to the Standard Allowance table consistent with prior practice and utilizing the ordered rates resulting from this case (Robinson, 5T 2723; Willis, 5T 3229-31).

XVII. RIDER 14

Rider 14 provides for the payment for energy that outflows from customers to the Company. The Company proposes three changes to expand Rider 14's availability and capacity (Willis, 5T 3205-3207).

First, Rider 14 is currently available to Rate Schedules D1, D3, and D4. The Company proposes to expand Rider 14's availability to all full-service customers, except where noted on the customer's applicable tariff. Rider 14 would remain inapplicable on any other service or rider. This change would expand customer optionality in how they manage their energy (Willis, 5T 3205).

Second, Rider 14 is: "Available to customers with on-site distributed generation desiring to operate in parallel with the Company's system and take service for their supplemental needs." The Company proposes to amend the tariff to include battery electric vehicles and stationary storage. The addition of battery electric vehicles will support future vehicle-to-grid applications. The addition of stationary storage will allow customers to have more flexibility in utilizing their assets (Willis, 5T 3205-3206).

[137] No contrary evidence has been presented, so the Company is unable to respond in further detail. In *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), our Supreme Court explained that "[t]he 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 proven must be taken as not existing, since a decision cannot be based upon conjecture. *Star Steel v USF&G*, 186 Mich App 475, 481; 465 NW2d 17 (1990); *see also, Skinner v Square D Co*, 445 Mich 153; 516 NW2d 475 (1994). There is no requirement to even respond to unfounded allegations. *Lendberg v Brotherton Iron Mining Co*, 75 Mich 84, 89; 42 NW 675 (1889).

Third, the Company proposes to increase the capacity limit from 100kW to 150kW to better align the capacity limitations across existing programs and products offered by the Company, such as the current DG program (Willis, 5T 3206).

MEIU and MNSC proposed that storage outflow should be compensated at full retail rates. The Company explained that the Commission should reject the proposals because they improperly focus on certain customers making profits instead of cost-based ratemaking.[138] Staff similarly recommended that compensating battery or V2G exports at full retail be rejected (e.g., Staff Initial Brief, p 137), but suggested: "In the near future, it would be most appropriately designed as a demand response tariff using the same principles as other such tariffs. Absent such a tariff, a customer could still discharge their battery to offset their own usage, which would reduce imports charged at full retail" (Krause, 7T 4539). The PFD states:

> This PFD agrees with Staff and MEIU (in part), finding that the company's proposal to include V2G and stationary battery flow in R14 is inappropriate. Instead, the PFD finds Mr. Krause's testimony persuasive, and recommends that the Commission direct DTE to develop a DR tariff for customers with V2G or stationary batteries wishing to participate in demand response events. [PFD, p 798.]

The Company maintains that the Commission should (1) adopt the Company's proposal to amend the applicability and availability of Rider 14 as proposed, including the addition of storage as an eligible resource. And (2) reject the proposals to provide full retail credits to storage outflow, which improperly focus on certain customers making profits instead of cost-based ratemaking (Willis, 5T 3234).

[138] Rider 14 is available to a wide variety of technologies, and the Company's proposal extends that availability to storage. It would be inappropriate to alter the rate design that applies to the various technologies supported on Rider 14. The currently-approved Rider 14 is an LMP-based rate with customer compensation designed to reflect the power supply costs avoided by the Company for their outflow. This framework of closely linking compensation and avoided cost is correct. The proposals to provide retail credits for storage outflow have no cost basis and would generate unjustified profits for certain customers. They also inaccurately imply that charging and discharging storage do not utilize the grid, and there is no cost responsibility for grid operation and maintenance. Thus, the proposals are nothing but requests for a subsidy without justification or legal authority (Willis, 5T 3232-3234).

XVIII. RATE SCHEDULES D4, D6.2, AND D11

The Company proposes to change Rate Schedule D4 (the Company's large general service commercial secondary rate). Within power supply, all capacity costs are recovered through a demand charge, and a portion of non-capacity costs are also recovered through a demand charge. The balance of the non-capacity costs are recovered through energy charges. The Company proposes to limit the change in the ratio of demand and energy charges for D4 power supply to no more than 15% compared to the currently-effective rates. This change is to ensure that customers on the rate are not subject to excessive volatility in how they are charged. The Company did not propose any change to the D4 design methodology other than to apply gradualism to changes in the demand/energy ratios (Pollack, 5T 3108-10).

Staff disagreed and proposed to maintain the current ratio between demand and energy revenue collection of roughly 53% demand and 47% energy, changing the methodology from currently-approved rate design, rather than limit the change between energy and demand as the Company proposed.

Similarly, primary rate schedules D11 and D6.2 have both demand-based and energy-based rates. The Company proposes to limit the change in the ratio of demand and energy charges for D11 and D6.2 power supply to no more than 15% compared to the currently-effective rates. This change is to ensure that customers on the rate are not subject to excessive volatility in how they are charged (Pollack, 5T 3112-13).

ABATE proposed to either obtain a 62% demand / 38% energy split of costs, or in the alternative that "the current primary class split of 47% demand and 53% energy be maintained" (ABATE's Initial Brief, p 61; Andrews, 4T 1095-96). The Company disagreed. Staff's Initial Brief, pp 123-24, similarly disagreed with ABATE's reasoning and primary proposal, but agreed with ABATE's proposed alternative, which is consistent with Staff's proposal regarding Rate D4.

The PFD states:

> This PFD declines to recommend the main proposal offered by ABATE for the reasons identified by DTE, Staff and Kroger. Further, this PFD also declines to recommend DTE's proposal to impose an artificial limit on the rate of change between demand and energy charges, which was also supported by Kroger.
>
> Instead, this PFD recommends adopting Staff's proposal (which was also aligned with ABATE's alternative proposal) to maintain the current ratio between demand and energy charges for rates D4, D6.2, and D11. This course of action maintains stability and prevents unnecessary volatility. This PFD views DTE's artificial limit as a well-intentioned proposal; nevertheless, it is analogous to treating symptom rather than the cause of the problem. Like Staff, this PFD is less concerned about the amount of DTE's proposed limit and more concerned about the need for such an artificial limit in the first place. The current methodology used to calculate the ratio may need to be refined or reformulated in future cases because it is apparently susceptible to an unacceptable level of volatility when the ratio of demand to energy charges should be significantly more stable. [PFD, p 814.]

The Company agrees that ABATE's main proposal should be rejected, but maintains that its own proposal should be adopted. The PFD's criticism of the Company's proposal as an "artificial limit" is unfounded. The Company's only change from currently-approved rate design is the limit on the shift of power supply demand-based recovery to power supply energy-based recovery, which would reduce volatility and be in accordance with the principle of gradualism, as indicated above. Using Rate D11 as a further example, the current ratio using rates approved in Case No. U-20836 is 47% demand / 53% energy. Using the identical method in the instant case, the ratio would be 23% demand / 77% energy, so the Company's proposed limit is appropriate. Therefore, the Commission should adopt the Company's proposal to limit the percentage change in the ratio of demand to energy in any one case to 15% on any given rate schedule (Pollack, 5T 3120-21).

Kroger's Initial Brief, pp 3-6, similarly recommended that the Commission reject ABATE's 62/38 rate design proposal and approve the Company's proposal, explaining in part that "DTE's proposal is largely consistent with the previously-approved SRM Capacity Charge based rate design methodology that was approved by the Commission in DTE's 2007 general rate case and employed

by DTE to establish D11 rates in the last four rate cases, with the exception of the proposed gradualism adjustment. In contrast, Mr. Andrews' proposal would represent a significant deviation from this historical precedent . . . the rate design *methodology* should not be modified on an ad hoc basis in this case to achieve a desired outcome" (*Id*., pp 4-5. Emphasis original).

Kroger's Initial Brief, pp 5-8, further recommended that the Commission reject the ABATE/Staff alternative proposal (maintain 47/53 ratio), explaining in part that the "proposal would represent a significant deviation from the Commission-approved SRM Capacity Charge rate design *methodology* that has been utilized by DTE in the last four general rate cases, while DTE's proposed rate design would largely be consistent with existing methodology, with the exception of the proposed gradualism adjustment" (*Id*., p 7. Emphasis original).

Therefore, the Commission should reject the PFD's proposal, and adopt the Company's proposal to use the currently-approved rate design and limit the percentage change in the ratio of demand to energy in any one case to 15% on any given rate schedule (Pollack, 5T 3112-13, 3120-21).

XIX. TIME-OF-USE (TOU) COMMERCIAL SECONDARY AND PRIMARY RATES

MEIU proposed that the Commission direct the Company to replicate the design of Rate Schedule D1.11 (Residential TOU) for commercial secondary and primary customers. The Company explained why it would be improper to replicate residential rate design for commercial and primary customers,[139] and that Mr. Barnes' proposal that the Company file tariffs within 30

[139] MEIU witness Barnes proposed that the Commission direct the Company to replicate the design of Rate Schedule D1.11 (Residential TOU) for commercial secondary and primary customers, suggesting that there are no significant issues because D1.11 has already been approved based on a considerable record of evidence (Barnes, 6T 4237, 4247-50). The Company disagrees because the "considerable record of evidence" concerned residential rate design. There is no record of evidence regarding D1.11 and commercial or primary customers. Residential customers also have different

days of the Commission's order in this case is also unreasonable (See generally, DTE Electric's Initial Brief, pp 300-301). Staff conceptually agreed with offering a TOU rate, but disagreed with the suggested rate design and timing, so Staff "recommends that the Commission and the ALJ reject EIBC/IEI/United's proposal to establish new rates," but direct the Company "to, in its next rate case, propose a rate structure for an optional primary and secondary TOU rate as described by EIBC/IEI/United but retain the distribution demand charges of rate D4 and D11" (Staff's Initial Brief, p 128). The PFD states:

> This PFD agrees with Staff, MEIU, and ABATE that optional TOU rates for commercial secondary and primary customers could be beneficial, noting that Consumers Energy has established such rates for its larger customers. While DTE complains that the TOU pricing window for residential Rate D1.11 is not appropriate for C&I customers, concerns like that can be addressed in a separate proceeding, as can the efficacy of demand charges under Rates D4 and D11. Accordingly, this PFD recommends that the Commission direct DTE to develop and present optional TOU tariffs for commercial secondary and primary customers as part of a separate, contested proceeding within 30 days of the final order in this case. [PFD, pp 819-20.]

The Company takes exception on three issues, (1) substance, (2) timing, and (3) the proper regulatory proceeding. Substantively, the PFD notes above that many intervenors believe TOU rates

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characteristics than commercial and primary customers. For example, witness Barnes suggested a pricing window for every customer group based on a rate design reflecting residential usage patterns. Time-of-use rates for commercial secondary and primary customers must be addressed on their merits (whatever the merits might be, and for each customer group separately, using the specific and relevant data for each proposed application), and cannot simply be copied from residential rates as Mr. Barnes proposed. Moreover, due to the inconsistencies in Mr. Barnes' testimony, the Company is unable to discern what he would consider to be an acceptable commercial secondary and primary time-of-use rate design beyond simply replicating the D1.11 residential rate design. Therefore, the proposal should be summarily rejected (Willis, 5T 3235-38, 3241-42).

Mr. Barnes also suggested that demand rates are inappropriate (Barnes, 6T 4238). To the contrary, large customer rate design across the country appropriately uses demand rates to charge customers based on their peak usage, which in the case of primary customers, is substantial. Allowing low load factor primary voltage customers to choose a time-of-use rate would shift costs to other customers as they would provide a decreasing share of their cost to serve. Thus, primary voltage demand charges remain the most appropriate way to price electric service for large customers (Willis, 5T 3238-39). Mr. Barnes further suggested that customers should have options, but optionality cannot exist apart from cost alignment. There also already are options in commercial pricing (D3, D4, D1.8, and D3.3) and primary pricing (D11, D8, and Rider 10) (Willis, 5T 3239-40).

"could be beneficial" to commercial and industrial customers. The Company reiterates not only is D11 a primary, time-variant rate, but all industrial and commercial customers have access to a time of use rate should they avail themselves of those options (Willis, 5T 3239-40). Thus, there is no demonstrated shortcoming in the Company's rate options. Moreover, the PFD suggests there is an open question about the role of demand charges in primary rate design, a point about which no intervenor provided demonstrable evidence. With respect to timing, the PFD largely replicates Mr. Barnes' proposal and recommends the Company file new tariffs in a new contested case within 30 days of the Commission's order in this case. This proposed timing is unreasonable, not least because the Company would have to develop the actual rate design and tariffs (neither of which have been developed or agreed upon in the instant case) in a compressed timeline while also meeting the timeline requirements of filing all ordered rates in this case within 30 days (Willis, 5T 3241-42). With respect to the proper regulatory proceeding, the Company has general rate cases to address tariffs and rate design to ensure proper consideration of overall cost and rates. A separate proceeding would be duplicative, onerous, and susceptible to error. The issues raised by the Company, including the likelihood of cost shifting between customers and impacts to reduced cost recovery, require that this matter be handled in a general rate case to the extent the Commission deems the general concept appropriate (Willis, 5T 3238-39).

XX. STREETLIGHTING RATE DESIGN

The Company explained and supported its Community Lighting rates, and opposed MAUI's proposal that the E1 streetlighting tariff be amended to provide that the Company issue to any E1 requesting streetlighting customer an annual report (or quarterly report for customers with more than 5,000 lights) providing streetlight outage occurrence counts, average outage duration, and

counts of outages lasting longer than 14 days (See generally, DTE Electric's Initial Brief, pp 285-88). The PFD states:

> This PFD recommends adopting MAUI's proposed addition to the E1 tariff to allow local governments to request annual (or for larger customers, quarterly) streetlight outage reports. The proposed language prescribes a reasonable two-month timeframe in which the utility can respond to the requests. Further, this PFD does not view the three required datapoints as particularly onerous. Indeed, the number of streetlight outage occurrence counts, the average duration thereof, and the number of outages lasting longer than 14 days does not appear to be overly burdensome. While some of Mr. Bellini's testimony seemed to suggest that MAUI was requesting detail at the level of individual streetlights, this PFD does not interpret "streetlight outage occurrence counts" to pertain to individual streetlights but rather to the same type of broader outage events that the company already acknowledged that its system tracks.
>
> DTE also stated that it could accommodate MAUI's request to include outages discovered by night patrols provided that it pertained to aggregate outage detail reflected in Exhibit A-40, schedule EE3. Accordingly, this PFD recommends adopting the proposed changes to Tariff E1 and directing DTE to collaborate with Staff, MAUI, and other interested parties to develop a streamlined outage report request process, a standardized report format, data protocols, and delivery method. [PFD, pp 844-45.]

The Company maintains its position but acknowledges that the PFD's interpretation of "streetlight outage occurrence counts" (broader outage events) is less onerous than MAUI's apparent proposal (individual streetlight detail). The record reflects that the Company's current outage management system (OMS) does not have this capability. It currently does not capture customer-reported outages by light, but instead by event (which could be many lights) (5T 2665). The Company continues to be transparent with respect to its performance and continues to evaluate and employ solutions to improve reliability and reduce outages. For example, the Company proactively implemented a night patrol program in 2019, and proactively implemented its cable

replacement program effective in 2022 (Bellini, 5T 2628-29, 2667). [140] Interestingly, Witness Bunch in his direct testimony in Consumers case U-20697, filed in 2020, used DTE's outage performance to contrast that of Consumers when reflecting on their 2018 outage duration. Specifically, he stated "Over the last ten years, DTE has reduced average outage duration from 8.5 days to 3.5 days and has reduced the incidence of outages longer than 10 days almost 90%." (U-20697, Direct Testimony of Bunch, pp 55-56). He goes on to recognize these efforts as "significant improvements." Therefore, the proposal to modify the E1 streetlighting tariff should be rejected as impractical and unnecessary. [141]

XXI. OTHER PROPOSALS

A. Environmental Justice in System Reliability and Distribution Planning

Staff's Initial Brief, pp 168-212, presented a wide-ranging discussion generally concerning environmental justice (EJ) and reliability, including various fluid positions and new assertions, along with a list of recommendations (recounted at PFD, pp 846-48). The PFD "finds that Staff's recommendations should be adopted, with the exception of requiring DTE to undertake a regression analysis" (PFD, p 848), and that CEO's "requests are sufficiently similar to Staff requests that resolution of Staff's recommendations should resolve the CEO recommendations" (PFD, p 851).

[140] To the extent that MAUI Mr. Bunch's proposal that the Company "include outages discovered by night patrols in its reports" (4T 934) pertains to aggregate outage detail reflected in Exhibit A-40, Schedule EE3, the Company agrees and will do so effective 2024 (Bellini, 5T 2668).

[141] The suggestion also implicates the AG's concerns regarding the ever-expanding volume of information in general rate case proceedings (AG Initial Brief p. 14 *"…testimony is often wordy but does not get to the essence of the issues that intervenors and the Commission Staff are interested in…Some of the exhibits have become too lengthy and full of unnecessary minutia…*). Repeated demands for more and more detailed information from more and more parties have predictable consequences. It would be reasonable to consider the likely marginal benefit and diminishing returns associated with additional production of further detail, study, and analysis.

The Company is particularly concerned about the PFD's endorsement of Staff's recommendation that "the Commission require the Company to develop a clear and repeatable process that allows interested parties to request, safely obtain, and use GIS data with different levels of detail for their own analyses" (PFD, p 847). This extremely broad recommendation threatens an unlawful result under FERC regulations related to Critical Energy/Electric Infrastructure Information (CEII) Regulations (Orders No. 833, 702, 683, 662, 649, 643, 630-A, 630) due to dangers to the security of the electrical system posed by GIS-level data being provided without a prespecified process for data protection. Additionally, the Company does not have the tools, resources, and capabilities to implement a repeatable process to allow any interested party to obtain and use GIS data for their own unspecified analysis. Aside from the obvious security risks and legal concerns broad access to this information would present, developing such a system would likely be extremely costly and have to be supported by all customers through rates.

The Company maintains that its method for evaluating reliability metrics in vulnerable communities is reasonable and prudent and demonstrates that its past and proposed investments are significantly focused on vulnerable communities. Consistent with the Company's 2021 Distribution Grid Plan and the Commission's March 3, 2022 order in Case No. U-21122, DTE Electric provided a geographic representation of reliability data by census tract across the Company's service territory (Kryscynski, 3T 404-11). Going further, the Company overlaid reliability data with vulnerable census tracts which were determined using an 80% threshold definition for vulnerable communities using the draft MiEJScreen tool score, consistent with the U.S. Environmental Protection Agency approach (Kryscynski, 3T 402). When compared to the remainder of the service territory, the 483 census tracts identified as vulnerable communities collectively had above average reliability performance in years 2020 through 2022 for SAIDI and SAIFI metrics excluding MEDs and All-

Weather SAIFI compared to the systemwide levels (Kryscynski 3T 411). In addition, the vast majority of the investment in the Company's proposed 2023-2024 conversion and 4.8kV hardening programs (85% and 90% respectively) is planned in vulnerable communities (Kryscynski, 3T 419).

Other intervening parties suggested alternative ways to evaluate environmental justice (EJ) related reliability. Staff witness Wang suggested utilizing a 1939 federal Home Owners Loan corporation (HOLC) map for the City of Detroit to determine if historic redlining persists in electric reliability investments. The Company does not believe that the 84-year-old HOLC map provides a valid basis to consider reliability metrics in EJ communities. The MiEJScreen tool, which incorporates 2020 census data, is more appropriate. The tool, which was also utilized by witness Wang in the Company's last electric rate case (Case No. U-20836), takes into account many present-day factors and was developed by state agencies and EJ experts to determine whether a community may be considered vulnerable (3T 430). Moreover, the projects that witness Wang overlayed onto the HOLC map do not provide a full picture of the Company's investments as her timeline was too condensed and, additionally, she did not consider the Company's 4.8kV conversion projects planned for 2023 which were not included on the Company's website[142] that are proposed for the yellow and red areas on the HOLC map. Considering past and proposed investments from 2018 to 2024 shows that DTE Electric has focused and is focusing numerous investments in areas that are the red and yellow areas on witness Wang's HOLC map (Kryscynski 3T 431-432).

CEO witness Periera and Staff witness Wang both suggested that the definition of vulnerable communities be reevaluated beyond the 80% to 100% threshold utilized by the Company (6T 3895-3896). The Company disagrees with these proposals to readjust the vulnerable

[142] Electric Reliability Improvements Map (arcgis.com)

community threshold at this time. The Company is early in its EJ journey and is identifying those customers who are the **most** vulnerable and who have also experienced poor reliability, and is developing plans to improve their reliability. Constantly adjusting those targets will slow the Company's efforts in this space.

The Company also values customer and stakeholder input and has many existing touchpoints and communication channels with customers where their needs, wants, and concerns are gathered (examples of customer outreach efforts are outlined in Ms. Crozier's testimony, 5T 2228-30). CEO's Initial Brief, pp 16-17, further suggested that since the Company did not plan historical investments with EJ in mind, it should not take credit for the investments benefiting vulnerable communities. To the contrary, the facts showing that the Company has made proper investments disprove various accusations against the Company, and further indicate that suggestions for the Company to provide additional detailed data and conduct alternative analyses are somewhat of a solution in search of a problem.

Finally, the Company notes that although it is not specifically aggrieved by the PFD's proposal regarding regression analysis (included in the PFD quote above), the PFD's presentation (here and elsewhere) seems to undeservedly discount the Company's legitimate critique of an intervenor position. Therefore, the Company clarifies that the regression analysis problem arose in this case because CEO witness Tan's regression analysis is so complex and rife with errors in statistical analysis and misinterpretation that it should not be used to determine vulnerable community status (Kryscynski 3T 435-439). Staff similarly recommended that "CEO's regression analysis should not be used as the basis for any recommendations" (Staff Initial Brief, p 117- 119).

The PFD presents an irreconcilable conundrum that would preclude needed investments in the distribution system: criticism that distribution system investments directed to safety and reliability are not evidence of vulnerable community focus, recommendations for large disallowances of proposed distribution system investments, including those in vulnerable communities, and speculation that the Company's further consideration of equity in a future DGP "argues in favor of caution when evaluating the company's spending proposals." (PFD pp. 188-189). The PFD lacks balance when assessing equity by indicating that outage duration times are longer on average in vulnerable communities, this is not correct, and it effectively dismisses the substantial investments made by the Company in those communities. (PFD, pp 188-189). When compared to the remainder of the service territory, the 483 census tracts identified as vulnerable communities collectively had above average reliability performance in years 2020 through 2022 for SAIDI and SAIFI metrics excluding MEDs and All-Weather SAIFI compared to the systemwide levels (Kryscynski 3T 411). In addition, the vast majority of the investment in the Company's proposed 2023-2024 conversion and 4.8kV hardening programs (85% and 90% respectively) is planned in vulnerable communities (Kryscynski 3T 419). [143] DTE Electric believes that its method for evaluating reliability metrics in vulnerable communities is reasonable and prudent, and demonstrates that its past and proposed investments are equitable and significantly focused on vulnerable communities.

The PFD has a "Tree trimming" caption and outlines some Staff recommendations (including an undergrounding analysis that has no apparent relation to tree trimming), but offers no

[143] Approximately 14% of the Company's customers are in the city of Detroit, but the Company is investing over 30% of its 2022-2024 strategic capital in the city. These projects address aging infrastructure and improve safety and

recommendation or reasoning (PFD, p 849). After an unrelated discussion, the PFD further states "MNSC asks the Commission to require DTE to present a plan in its next rate [*sic*] to improve reliability associated with trees along service lines. This is similar to Staff's recommendation, which this PFD recommends the Commission adopt" (PFD, p 851).

The Company objects because the PFD does not articulate any recommendation or support for a recommendation, which is contrary to requirements for a PFD (e.g., MCL 24.281(2)) and fundamental due process. [144] Without waiving its objections, but for purposes of attempting to assist the Commission by providing a fuller discussion, the Company surmises that the PFD portions relate to MNSC witness Ozar's recommendation that the Commission order the Company to "include an action plan in its next general rate filing" for a "pre-emptive service line tree maintenance program" (6T 3584).[145] Staff recognized that "tree trimming around residential service drops is the responsibility of the customer," but suggested: "It may be beneficial for the Company to take responsibility for service drop tree trimming. Staff recommends DTE develop a proposal

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reliability of the distribution system. The CODI and conversion projects in this case will convert the system serving more than 50,000 residential Detroit customers from 4.8kV to 13.2kV (Deol, 2T 213).

Mr. Kryscynski further discussed environmental justice, responded to various indicated concerns and suggestions, and demonstrated how the Company's investments are supporting vulnerable customers and communities (3T 400-420, 428-47).

[144] DTE Electric has Due Process rights under the Fourteenth Amendment to the United States Constitution. Michigan's Constitution similarly provides similar protections as well as an explicit right to fair and just treatment in MPSC proceedings. Michigan Const 1963, art 1, § 17 provides: "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."

[145] A "service drop" is generally the term used for an overhead secondary conductor running from a utility pole, across a customer's property, to a meter installed on a house (for a typical residential customer). Utilities typically have a right-of-way (ROW) that allows them to trim vegetation surrounding their wires running from pole to pole. The Company does not have the same ROWs for service drops (Hartwick, 5T 2163).

for a residential service drop tree trimming pilot [including] the estimated costs for the pilot and a good area of their service territory in which to conduct it" (Duell, 7T 4402).

These suggestions are not reasonable and prudent at this time. The Company understands the underlying concerns and would consider pilots in the future. Before initiating a pilot, however, the Company would need to conduct a study to estimate the scope, cost, resources required, and projected reliability improvement. That would be a significant task. Benchmarking indicates that other utilities do not perform service drop trimming, so there is little, if any, industry data available regarding service drop trimming (Hartwick, 5T 2164). While the Company believes that the topic is worthy of further study, the requisite time for study will not allow for any meaningful results to be included in DTE Electric's next rate case.

XXII. MISS DIG

Staff made four recommendations regarding the MISS DIG process (Becker, 7T 4351-52). The PFD agrees (PFD, p 850). The Company does not object to these recommendations. Going forward, the Company will track expenditures for damage caused by the Company to its own facilities despite the low rate of occurrence. This represents a change to the Company's prior position (5T 2831-32).

XXIII. IT AUDIT

DAAO witness Koeppel suggested that "the Commission open an inquiry into the standards for treating IT investments as capital." The Company disagrees because its capitalization policy for IT projects is consistent with the rules in the Uniform System of Accounts and Generally Accepted Accounting Principles. DAAO's call for an inquiry lacks merit and therefore, should be rejected (Uzenski, 5T 1519-20, 156, 1582).

The PFD also apparently did not find merit in DAAO's suggestion, but complained (here and elsewhere) about the volume and complexity of the Company's evidentiary presentation, and "does recommend that the Commission consider some remedial action to get a better handle on the costs and benefits of the projects" (PFD, p 854).

The Company objects because the PFD does not articulate any recommendation or support for a recommendation, which is contrary to requirements for a PFD (e.g., MCL 24.281(2)) and fundamental due process. [146] The Company further notes that it has filed extensive testimony and exhibits in response to the Commission's increasing filing requirements, and that it has made significant efforts to address feedback from Staff and the Commission by providing exhibits with additional project details, as discussed in section IV. A. 13.[147]

XXIV. 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

[146] DTE Electric has Due Process rights under the Fourteenth Amendment to the United States Constitution. Michigan's Constitution similarly provides similar protections as well as an explicit right to fair and just treatment in MPSC proceedings. Michigan Const 1963, art 1, § 17 provides: "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."

[147] The suggestion also implicates the AG's concerns regarding the ever-expanding volume of information in general rate case proceedings (AG Initial Brief p. 14 *"…testimony is often wordy but does not get to the essence of the issues that intervenors and the Commission Staff are interested in…Some of the exhibits have become too lengthy and full of unnecessary minutia…*). Repeated demands for more and more detailed information from more and more parties have predictable consequences. It would be reasonable to consider the likely marginal benefit and diminishing returns associated with additional production of further detail, study, and analysis.

approximately $580 million ($583 million without approval of the IRM), based on a December 1, 2023 through November 30, 2024 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 December 10, 2023 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 Company's proposed IRM;

J. Approving all proposed pilot programs as requested by the Company;

K. Approving all proposed regulatory accounting treatments as requested by the Company;

L. Approving the capacity charge calculated by the Company, which is based on the methodology utilized in Case No. U-20836, and approving the capacity-related costs supported by the Company in this proceeding;

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: Andrea E. Hayden
Digitally signed by Andrea E. Hayden
Date: 2023.10.27 16:03:00 -04'00'

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Dated: October 27, 2023

DTE Electric Company
Computation of Revenue Deficiency
Projected 12 Month Period Ending November 30, 2024
($000)

MPSC Case No. U-21297
Exceptions to PFD
Attachment A

Line No.	(a) Description	(b) Company Reply Brief	(c) Adjustments	(d) Exceptions to PFD Position	(e) ALJ Proposal for Decision	(f) Difference
1	Rate Base (1)	$ 22,533,543	$ -	$ 22,533,543	$ 21,857,855	$ 675,688
2	Adjusted Net Operating Income (2)	861,054	-	861,054	1,000,789	(139,735)
3	Rate of Return (3)	5.6986%	0.0000%	5.6986%	5.5217%	0.1769%
4	Income Requirements	1,284,096	-	1,284,096	1,206,915	77,181
5	Income Deficiency (Sufficiency)	423,042	-	423,042	206,126	216,916
6	Revenue Conversion Factor (4)	1.3496	-	1.3496	1.3496	-
7	**Rev Deficiency / (Sufficiency)**	**$ 570,952**	**$ 0**	**$ 570,952**	**$ 278,195**	**$ 292,757**
8	Tree Trim Surge (5)	8,847	-	8,847	8,847	-
9	**Revenue Deficiency / (Sufficiency) - Total**	**$ 579,799**	**$ 0**	**$ 579,799**	**$ 287,042**	**$ 292,757**
10	Add IRM Revenue Deficiency to Base Rates (6)	3,406	-	3,406	3,406	-
11	**Revenue Deficiency / (Sufficiency) - Alternative**	**$ 583,205**	**$ 0**	**$ 583,205**	**$ 290,448**	**$ 292,757**

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
(6) Exhibit A-34, Schedule Y1

Line No.	(a) Description	(b) Company Reply Brief	(c) Adjustments	(d) Exceptions to PFD Position	(e) ALJ Proposal for Decision	(f) Difference
1	Plant in Service	$ 26,439,617	$ -	$ 26,439,617	$ 26,026,316	$ 413,301
2	Plant Held for Future Use	76,508		76,508	76,508	-
3	Construction Work in Progress	2,407,270		2,407,270	2,317,664	89,606
4	Total Utility Plant	28,923,394	-	28,923,394	28,420,488	502,907
5						
6	Less: Depreciation Reserve	7,840,725		7,840,725	7,952,049	(111,324)
7						
8	Net Utility Plant	21,082,670	-	21,082,670	20,468,439	614,231
9						
10	Net Capital Lease Property	11,636		11,636	11,636	-
11	Net Nuclear Fuel Property	201,880		201,880	201,880	-
12						
13	Total Utility Property and Plant	21,296,186	-	21,296,186	20,681,955	614,231
14						
15	Less: Capital Lease Obligations	13,486		13,486	13,486	-
16						
17	Net Plant	21,282,700	-	21,282,700	20,668,470	614,231
18						
19	Allowance for Working Capital	1,250,843		1,250,843	1,189,385	61,457
20						
21						
22	Rate Base	$ 22,533,543	$ -	$ 22,533,543	$ 21,857,855	$ 675,688

Line No.	(a) Description	(b) Company Reply Brief	(c) Adjustments	(d) Exceptions to PFD Position	(e) ALJ Proposal for Decision	(f) Difference
1	**Operating Revenues**					
2	Sales Revenues	$ 5,112,874	$ -	$ 5,112,874	$ 5,113,181	$ 307
3	Other Operating Revenue	-		-	-	-
4	Fuel and Purchased Power	1,361,901		1,361,901	1,361,750	(150)
5	Net Margin	3,750,973	-	3,750,973	3,751,430	457
6						
7	**Operating Expenses**					
8	Operations and Maintenance Expenses	1,293,217		1,293,217	1,132,015	(161,202)
9	Depreciation and Amortizations	1,160,322		1,160,322	1,129,452	(30,870)
10	Property Taxes	320,250		320,250	320,250	-
11	Other Taxes	50,173		50,173	50,173	-
12	Total Operating Expenses	2,823,962	-	2,823,962	2,631,890	(192,072)
13						
14	**Operating Income**	927,011	-	927,011	1,119,541	192,529
15						
16	**Other Operating Income Adjustments**					
17	Allow. For Funds Used During Constr	53,633		53,633	53,633	(0)
18	Amortization of Loss on Reacquired Debt	(2,980)		(2,980)	(2,980)	(0)
19	Other Income	(1,277)		(1,277)	(1,277)	-
20	Total Operating Income Adjustments	49,376	-	49,376	49,376	(1)
21						
22	**PreTax Adjusted Net Operating Income**	$ 976,388	$ -	$ 976,388	$ 1,168,916	$ 192,528
23						
24	State Income Taxes	65,870	-	65,870	78,525	12,655
25	Federal Income Taxes	49,464	-	49,464	89,602	40,138
26						
27	**Net Operating Income**	$ 861,054	$ -	$ 861,054	$ 1,000,789	$ 139,735

DTE Electric Company
Rate of Return Summary
Projected 12 Month Period Ending November 30, 2024
Based on Average Rate Base
($000)

MPSC Case No. U-21297
Exceptions to PFD
Attachment A

Line No.	(a) Description	(b) Amounts ($000)	(c) Capital Structure Percent Permanent Capital	(d) Percent of Total Capital	(e) Cost Rate %	(f) Weighted Costs Permanent Capital	(g) Total Cost %	(h) Conversion Factor	(i) Pre-Tax Return
	U-21297 Filed Position (Test Period Average Basis)								
1	Long-Term Debt	$ 8,876,109	50.00%	39.26%	4.06%	2.028%	1.59%	100.000%	1.592%
2	Preferred Stock	0		0.00%	0.00%	0.000%	0.00%	134.964%	0.000%
3	Common Shareholders' Equity	8,876,081	50.00%	39.26%	10.25%	5.125%	4.02%	134.964%	5.431%
4	Total	17,752,190	100.00%			7.153%			
5									
6	Short-Term Debt	330,941		1.46%	4.98%		0.07%	100.000%	0.073%
7									
8									
9									
10	Job Development - ITC - Debt	15,986		0.07%	4.06%		0.00%	100.000%	0.003%
11	Job Development - ITC Equity	15,986		0.07%	10.25%		0.01%	134.964%	0.010%
12	Total Job Development - ITC	31,973							
13									
14	Deferred Income Taxes (Net)	4,496,126		19.88%	0.00%		0.00%		0.000%
15									
16	Total	22,611,230		100.00%			5.70%		7.108%
	U-21297 Exceptions to PFD Position (Test Period Average Basis)								
17	Long-Term Debt	$ 8,876,109	50.00%	39.26%	4.06%	2.028%	1.59%	100.000%	1.592%
18	Preferred Stock	0			0.00%	0.000%	0.00%	134.964%	0.000%
19	Common Shareholders' Equity	8,876,081	50.00%	39.26%	10.25%	5.125%	4.02%	134.964%	5.431%
20	Total	17,752,190	100.00%			7.153%			
21									
22	Short-Term Debt	330,941		1.46%	4.98%		0.07%	100.000%	0.073%
23									
24									
25									
26	Job Development - ITC - Debt	15,986		0.07%	4.06%		0.00%	100.000%	0.003%
27	Job Development - ITC Equity	15,986		0.07%	10.25%		0.01%	134.964%	0.010%
28	Total Job Development - ITC	31,973							
29									
30	Deferred Income Taxes (Net)	4,496,126		19.88%	0.00%		0.00%		0.000%
31									
32	Total	22,611,230		100.00%			5.70%		7.108%

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-21297

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

CAITLIN D. MYERS states that on October 27, 2023, she served a copy of DTE Electric Company's Exceptions to the Proposal for Decision and Attachment A in the above captioned matter, via electronic mail, upon the persons listed on the attached service list.

Caitlin Myers Digitally signed by Caitlin Myers Date: 2023.10.27 16:03:30 -04'00'

CAITLIN D. MYERS

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