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October 3, 2024

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

RE: In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority
MPSC Case No. U-21534

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter is DTE Electric Company's Initial Brief. Also attached is the Proof of Service.

Very truly yours,

Jon P. Christinidis

Digitally signed by Jon P. Christinidis
Date: 2024.10.03 15:36:15 -04'00'

Jon P. Christinidis

JPC/erb
Attachments
cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	)))))))	Case No. U-21534

DTE ELECTRIC COMPANY'S

INITIAL BRIEF

Dated: October 3, 2024

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I. INTRODUCTION AND SUMMARY OF MAJOR ISSUES

This case began on March 28, 2024, when DTE Electric Company (DTE Electric or the Company) filed its Application and supporting direct testimony and exhibits, requesting a jurisdictional rate increase of $456.4 million (Exhibit A-11, Schedule A1, line 11) and other forms of regulatory relief, using a projected test year of January 1, 2025 through December 31, 2025. The Company also proposes to extend and expand the investment recovery mechanism (IRM), which would result in additional revenue requirements of $80.6 million for 2026, and $172.4 million for 2027 (Exhibit A-33, Schedule X4, page 1, line 22, col. (e) and col. (f).

The Company's requested rate increase is necessary to pay for a modern, reliable, and cleaner electrical system. The Company is pursuing multi-year strategic initiatives to (1) rebuild, modernize, and automate its 46,000 miles of electric circuits (the "grid") to achieve reliability that is better than industry average by 2029,[1] and (2) replace aging coal plants with modern power-generation assets, such as wind turbines, large-scale solar arrays, and large battery installations. Customers will benefit from these initiatives through (1) fundamental improvements in the grid's reliability and ability to accommodate electric vehicles and other distributed energy resources, and (2) reduced carbon emissions from more efficient and cleaner sources of power generation (Foley, 2T 70-71, 75, 140).

Fully realizing these benefits will require significant investment. Various proposed disallowances of capital investments and operating expenses would challenge the Company's ability to invest at planned levels and meet its reliability and clean energy goals. The Company

[1] The Company is focused on reducing power outages by 30%, and cutting outage time in half over the next five years (30% fewer…50% faster…by 2029). This would result in better than industry median performance by 2029 for Average System Availability Index and All-Weather System Average Interruption Duration Index (SAIDI). These reliability improvements also have the potential to generate significant economic value (Foley, 2T 72-75, 140).

appreciates that it is asking its customers to pay higher electric bills; however, the cost is justified because the investments will generate significant benefits and value to customers, as well as the State of Michigan. Ongoing grid modernization efforts have already produced significant benefits. This case represents the next step toward improved reliability and cleaner generation, with corresponding additional benefits. The Company proposes to take this step at a reasonable cost to customers, as reflected for example by comparisons to the rate of inflation and both regional and national electric bills (Foley, 2T 71-75, 78-91, 140).[2]

DTE Electric initially requested that the Commission authorize an adjustment of rates to provide an additional $456.4 million (Vangilder, 6T 2811; Exhibit A-11, Schedule A1, line 11) based on $22.108 billion in rate base, which consisted of $20.813 billion of net plant, and $1.295 billion of working capital (Vangilder, 6T 2812; Exhibit A-12, Schedule B1, column (d)), and adjusted Net Operating Income (NOI) of $1,087.1 million in the projected test period (Uzenski, 6T 1510; Exhibit A-13, Schedule C1, line 17). After reviewing Staff's and other intervenors' positions and the full record in this case, DTE Electric requests rate relief for a projected revenue deficiency of $446.1 million. (See Company's Attachments A and B included with this Brief).

DTE Electric supported its requested rate relief through its direct and rebuttal testimony and the exhibits filed in this case. The Company also provided extensive support through the information required by the Commission's Part III filing requirements as established in Case No. U-18238. DTE Electric's testimony and exhibits demonstrate that the Company needs rate relief for the projected test year to continue to provide safe and reliable electric service to its customers.

[2] DTE Electric's residential electric bills were 11% below the national average in 2022, and 13% below the national average in 2023. Also, since 2021 DTE Electric's residential bill growth has remained below the rate of inflation, and below the rate of increase for peer utilities in both the Great Lakes region and nationally. The requested rate relief ($456 million; 37 cents/day for the average residential customer) would continue this trend with average bill growth of 3.1% since 2021, which is below the 4.2% projected level of average inflation, and 4.5% per year Great Lakes region residential bill growth between 2021 and 2023, and 5.8% national electric bill growth (Foley, 2T 82-83).

Therefore, DTE Electric requests that the Commission authorize an adjustment of rates to provide $446.1 million annually.

II. HISTORY OF PROCEEDINGS

DTE Electric is presently serving its jurisdictional electric customers under rate schedules and charges approved by this Commission in, *inter alia*, its December 1, 2023 Order in Case No. U-21297.

On April 26, 2024, a pre-hearing conference was held and intervention was granted to the Michigan Attorney General (AG); the Association of Businesses Advocating Tariff Equity (ABATE); City of Ann Arbor (Ann Arbor); Ecology Center, Union of Concerned Scientists, Environmental Law & Policy Center, and Vote Solar (collectively the Clean Energy Organizations or CEO); Energy Michigan, Inc. (Energy Michigan or EM); EVgo Services, LLC (EVgo); Foundry Association of Michigan (FAM); Great Lakes Renewable Energy Association (GLREA); International Transmission Company (ITC); the Kroger Company (Kroger); Michigan Cable Telecommunications Association (MCTA); Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United (collectively MEIU); the Michigan Environmental Council (MEC), Natural Resource Defense Council (NRDC), the Sierra Club (SC) and the Citizens Utility Board of Michigan (CUB) (collectively MNSC); Michigan Municipal Association for Utility Issues (MI-MAUI); Soulardarity and We Want Green, Too (collectively the Detroit Area Advocacy Organizations or DAAO); Utility Workers Union of America, Local 223 (Local 223); and Wal-Mart, Inc. (Wal-Mart). (1T 14). On May 16, 2024, late intervention was granted to Electrify America.

Along with its Application, DTE Electric provided direct testimony and exhibits of 28 witnesses in support of its request for a rate increase and other regulatory relief:

- Robert A. Bellini is the Manager of Community Lighting (qualifications and direct testimony at 6T 3095-3141);
- Pina Bennett is the Director of Electric Marketing (qualifications and direct testimony at 6T 1917-88);
- Shawn D. Burgdorf is the Manager of the Power Supply Strategy & Modeling team in DTE Electric's Generation Optimization department (qualifications and direct testimony at 6T 2333-45);
- Jeffrey C. Davis is DTE Electric's Expert - Nuclear Strategic Business Operations (qualifications and direct testimony at 6T 1802-79);
- Satvir Deol is the Director of Central Engineering (qualifications and direct testimony at 5T 1130-1218);
- Morgan Elliott Andahazy is the Director, Project Management Organization (PMO) (qualifications and direct testimony at 4T 904-1020);
- Keegan O. Farrell is the Manager of Demand Response (DR) (qualifications and direct testimony at 6T 2657-2708);
- Mathew A. Fix is the Director of Compensation and Retirement Income for DTE Energy Corporate Services LLC (qualifications and direct testimony at 6T 2850-97);[3]
- Neal T. Foley is the Director of Regulatory Affairs for DTE Energy Corporate Services LLC (qualifications and direct testimony at 2T 66-136);[4]

[3] Mr. Fix adopted portions of the originally-filed direct testimony of Michael S. Cooper regarding employee compensation practices and benefit expense related to retirement income.

[4] Mr. Foley filed revised direct testimony adopting the originally-filed direct testimony of Adella F. Crozier.

- Margaret E. Guillaumin is the Plant Director, Operations Performance in the Energy Supply organization (qualifications and direct testimony at 6T 1582-1716);
- Shannen M. Hartwick is the Director of Conversion (qualifications and direct testimony at 4T 626-819); [5]
- Michael J. Hatsios is the Director – Customer Service Operations (qualifications and direct testimony at 6T 2184-2300);
- Brian L. Hill is the Director – Southwest Regional Customer Operations and Scheduling & Coordination (qualifications and direct testimony at 6T 3027-60);
- Jerome K. Hooper is DTE Energy Corporate Services LLC's Manager, Health & Welfare Benefits and Occupational Health (qualifications and direct testimony at 6T 2917-43);[6]
- Allen J. Kryscynski is the Director – Distribution Operations Regulatory Strategy and Grid Modernization (qualifications and direct testimony at 3T 292-394);
- Robert J. Lee is DTE Energy's Manager of Environmental Strategy (qualifications and direct testimony at 6T 2724-47);
- Timothy J. Lepczyk is the Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy and its subsidiaries, including DTE Electric (qualifications and direct testimony at 6T 2543-61);
- Markus B. Leuker is DTE Electric's Manager of Corporate Energy Forecasting (qualifications and direct testimony at 6T 1768-99);

[5] Witness Hartwick was the Director of Automation when her direct testimony was filed (4T 859).

[6] Mr. Hooper adopted portions of the originally-filed direct testimony of Michael S. Cooper regarding benefit expenses.

- Habeeb J. Maroun is a Regulatory Strategy Consultant in the Regulatory Requirements department of the Regulatory Affairs organization (qualifications and direct testimony at 6T 2749-77);
- David C. Milo is a Fuel Resource Specialist in the Operations and Logistics group of the Company's Fuel Supply department (qualifications and direct testimony at 6T 1748-66);
- Pankaj Sharma is the Director – Information Officer in DTE Energy Corporate Services LLC's Information Technology Services (ITS) organization (qualifications and direct testimony at 6T 2020B-2161);
- Jason E. Sparks is the Director of Revenue Management and Protection (RM&P) for DTE Energy Corporate Services LLC (qualifications and direct testimony at 6T 2354-77);
- Rachel C. Steudle is the Director of Tree Trimming (qualifications and direct testimony at 6T 2959-97);
- Theresa M. Uzenski is the Manager of Regulatory Accounting for DTE Electric and DTE Gas Company (DTE Gas) (qualifications and direct testimony at 6T 1461-1558);
- Kirk M. Vangilder is a Principal Financial Analyst for Revenue Requirements in DTE Energy's Regulatory Affairs organization (qualifications and direct testimony at 6T 2801-22);
- Dr. Bente Villadsen is a Principal of The Brattle Group, which is an economic, environmental and management consulting firm (qualifications and direct testimony at 6T 2401-86);

- Aaron Willis is Manager - Regulatory Economics (qualifications and direct testimony at 6T 2569-2615); and
- Sherri L. Wisniewski is DTE Energy's Director of Tax Operations (qualifications and direct testimony at 6T 2824-40).

On July 26, 2024, the Commission Staff and Intervenors filed their testimony and exhibits. Staff provided the testimony of Tayler Becker (6T 5029-42), Ryan Boutet (6T 5128-38), Elaina M. Braunschweig (6T 3520-38), Jonathan J. DeCooman (6T 5044-68), Roger A. Doherty (6T 5070-77), Jessica Duell (6T 5140-50), Ally Durfee (6T 5152-58), Nicholas M. Evans (6T 5222-37), Allan D. Freeman (6T 5079-89), Lauren Fromm (6T 5091-96), Justin J. Hecht (6T 4882-90), David W. Isakson (6T 45892-4901), Lisa M. Kindschy (6T 5172-89), Brittney Klocke (6T 5098-5104), Cody S. Mathews (6T 5160-70), Theresa McMillan-Sepkoski (6T 4917-28), Robert F. Nichols II, CPA (6T 4930-37), Mark J. Pung (6T 4939-51), Nicholas M. Revere (6T 4953-65), Danielle R. Rogers (6T 5106-26), Shannon Rueckert (6T 4986-96), Michelle L. Schreur (6T 4998-5003), and Joseph E. Ufolla (6T 5005-27).

ABATE provided the testimony of James R. Dauphinais (6T 3365-89), Christopher C. Walters (6T 3418-97), and Jessica A. York (6T 3328). The AG provided the testimony of Sebastian Coppola (6T 3584). The AG, MEC and NRDC (AG-MN) provided the testimony of Paul J. Alvarez (6T 3914-80), and Dennis Stephens (6T 3982-4030). Ann Arbor provided the testimony of Tiffany Giacobazzi (6T 4212-20), Cyrus Naheedy (6T 4222-31), Skye Stewart (6T 4233-41), and Dr. Mellissa Stults (6T 4243-76). CEO provided the testimony of William D. Kenworthy (6T 3187-3210), Boratha Tan (6T 3267-83), and Curt Volkmann (6T 3235-65). CUB/MEC provided the testimony of Matthew J. Bandyk (6T 3737-62), and Graham G. Woolley (6T 3833-54). CUB, MEC and NRDC (CUB-MN) provided the testimony of Joshua W. Denzler (6T 3765-80), and David L. Gard (6T 3819-31). DAAO provided the testimony of Elizabeth Jacob (6T 4632-63), Yunus

Kinkhabwala, PhD (6T 4528-67), Jackson Koeppel (6T 4369-4434), Arjun Makhijani, Ph.D. (6T 4569-4630), Delores Orr (6T 4699-4715), Justin Schott (6T 4448-4526), and Toyia Watts (6T 4665-97). Electrify America provided the testimony of Rhiannon Davis (6T 4763-71), and Jigar J. Shah (6T 4781-89). Energy Michigan provided the testimony of Alexander J. Zakem (6T 4163-86). EVgo provided the testimony of Lindsey Stegall (6T 3288-3308). GLREA provided the testimony of Robert Rafson (6T 4865-79), and John Richter (6T 4794-4864). ITC provided the testimony of Kwafo Adarkwa (6T 4744-49) and Pushkar Chindhade (6T 4751-55). MI-MIEU provided the testimony of Justin R. Barnes (6T 4130-60), and Dr. Laura S. Sherman (6T 4045-4111). MEC/NRDC provided the testimony of Roger Colton (6T 3856-3912). MNSC provided the testimony of Douglas B. Jester (6T 3782-3817). MI-MAUI provided the testimony of Richard Bunch (6T 4279-4364). Wal-Mart provided the testimony of Lisa V. Perry (6T 4718-42).

On August 16, 2024, DTE Electric filed the rebuttal testimony and exhibits of witnesses Bellini (6T 3142-81), Bennett (6T 1989-2018), Burgdorf (6T 2346-52), Davis (6T 1880-1914), Deol (5T 1219-70), Elliott-Andahazy (4T 1021-65), Farrell (6T 2709-22), Fix (6T 2898-2915), Foley (2T 137-86), Guillaumin (6T 1717-46), Hartwick (4T 820-57), Hatsios (6T 2301-30), Hill (6T 3061-92), Hooper (6T 2944-57), Kryscynski (3T 395-468), Lepczyk (6T 2562-66), Maroun (6T 2778-98), Sharma (6T 2162-81), Sparks (6T 2378-98), Steudle (6T 2998-3025), Uzenski (6T 1559-79), Villadsen (6T 2487-2540), Willis (6T 2616-45), and Wisniewski (6T 2841-47).[7]

Staff filed the qualifications and rebuttal testimony of Anne Armstrong (6T 5209-20) and Kevin S. Krause (6T 5191-5207), and the rebuttal testimony of witnesses Braunschweig (6T 3539-49), Isakson (6T 4903-15), and Revere (6T 4967-84).

[7] The Company presented an extensive discussion of various issues in its direct testimony and exhibits. The Company's reliance on its initial filing, and corresponding lack of rebuttal to further address various suggestions by Staff and Intervenors, should not be construed as acceptance of those suggestions.

ABATE filed the rebuttal testimony of Brian C. Andrews (6T 3505-15), and witnesses Dauphinais (6T 3390-3417), and Walters (6t 3498-3504). CEO filed the rebuttal testimony of witness Kenworthy (6T 3211-33). DAAO filed the rebuttal testimony of witness Koeppel (6T 4435-46). Electrify America filed the rebuttal testimony of witness Davis (6T 4772-80). Energy Michigan filed the rebuttal testimony of witness Zakem (6T 4187-4210). ITC filed the rebuttal testimony of witness Chindhade (6T 4756-59). MI-MEIU filed the rebuttal testimony of witness Sherman (6T 4112-28). MNSC filed the rebuttal testimony of witness Jester (6T 4032-41).

On September 4-6 and 9-10, 2024, the parties conducted cross-examination and bound in testimony and exhibits. Administrative Law Judge (ALJ) Sally Wallace presided over the hearing. The public record goes to 6T 5241, and continues with a confidential record (6T 5242-5468), and includes a multitude of exhibits. [8]

The Commission agreed to read the record, so there is no Proposal for Decision.

III. JURISDICTION, STANDARD OF REVIEW AND RATE SETTING LAW

A. Jurisdiction and Standard of Review

The Commission has jurisdiction over this case pursuant to 1909 PA 106, as amended, MCL 460.551 *et seq*.; 1909 PA 300, as amended, MCL 462.2 *et seq*.; 1919 PA 419, as amended, MCL 460.51 *et seq*.; 1939 PA 3, as amended, MCL 460.1 *et seq*.; 1969 PA 306, as amended, MCL 24.201 *et seq*.; and the Commission's Rules of Practice and Procedure, as amended, R 472.10401 *et seq*.

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

[8] The public transcript includes pages 6T 2020A and 2020B, and there is a gap from 6T 2646-54. The confidential transcript includes 4T 882-95, and 5T 1263-1304.

support a conclusion." *Monroe v State Employees' Retirement Sys*, 293 Mich App 594, 607; 809 NW2d 453 (2011). Expert testimony is "substantial" only if it is offered by a qualified expert who has an informed and rational basis for his or her view, even if other experts disagree. *Great Lakes Steel v Public Service Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983).

The preponderance of evidence standard applies in this proceeding. *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 evidence standard is the lightest of all evidentiary standards when compared to the heightened "clear and convincing" standard[9] or the "beyond a reasonable doubt" standard that is only applicable to criminal proceedings.[10] 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).]

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

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[9] *In re Moss*, 301 Mich App 76, 89-90; 836 NW2d 182 (2013).

[10] *Thangavelu v Dep't of Licensing & Regulation*, 149 Mich App 546, 554-555; 386 NW2d 584 (1986).

> 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 Administrative Procedures Act (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.[11]

The ability to take official notice is limited under applicable rules.[12] See also *Freed v Salas*, 286 Mich App 300, 341; 780 NW2d 844 (2009) (affirming the trial court's refusal to take judicial notice of a speed limit, explaining in part: "Given that the signage and the traffic control order did

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

[12] Rule 428 of the Commission's Rules of Practice and Procedure provides:

> Except as otherwise provided by law, the commission and the presiding officer ***may take official notice of judicially cognizable facts and may take notice of general, technical, or scientific facts within the commission's specialized knowledge***. The commission or the presiding officer shall notify the parties at the earliest practicable time of any noticed fact that pertains to a materially disputed issue that is being adjudicated and, on timely request, the parties shall be given an opportunity before the final decision to dispute the fact or its materiality. The commission may use its expertise, technical competence, and specialized knowledge in the evaluation of evidence presented to it." [R 792.10428. Emphasis added.]

MRE 201(b) similarly provides:

> ***A judicially noticed fact must be one not subject to reasonable dispute*** in that it is either (1) generally known within the territorial jurisdiction of the trial court or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned. (Emphasis added).

not agree as to the speed limit for the area, the fact could not reasonably be said to have been undisputed or capable of accurate and ready determination.")

The Commission previously explained that "because of the unforgiving time limits under MCL 460.6a [which at that time had a 12-month deadline], official notice requests, especially those that may generate controversy regarding the materiality or weight of the evidence proffered, can rarely, if ever, be entertained after the close of the record" (December 11, 2015 Order in Case No. U-17767, p 136, agreeing with ALJ's denial of official notice request).

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).

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).

B. Rate Setting Legal Requirements

In addition to the discussion above, utilities also have 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.[13]

The Michigan Supreme Court has provided further guidance that the Commission must use in setting DTE Electric's rates. Specifically, creating rates that recognize *reductions* in certain costs while ignoring the *increase* in other costs, violates the due process rights of utilities. The Court cited with approval the conclusions of a circuit court judge granting an injunction against such unlawful rates in *Michigan Consolidated Gas Company v Public Service Comm*, 389 Mich 624, 633; 209 NW2d 210 (1973) ("Certainly at first blush it would appear to anyone steeped in 'due process' considerations that it is grossly unfair to include certain items of decreased cost in rate determination while at the same time to exclude items of increased cost.")

As a matter of fundamental ratemaking law, DTE Electric is entitled to a commensurate return of and on its investment in providing utility service.[14] It is also axiomatic that utility rates are overall rates,[15] and that (with certain limited exceptions) "the commission shall ensure the

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[13] 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).

[14] 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).

[15] *Federal Power Comm, supra*, 320 US at 602; *Michigan Bell Telephone Co v Public Service Comm*, 332 Mich 7, 37; 50 NW2d 826 (1952); MCL 460.6a(2)(b).

establishment of electric rates equal to the cost of providing service to each customer class."[16] Proposals that are contrary to the controlling law of ratemaking are unlawful and merit no consideration.

DTE Electric's constitutional rights would be violated by a failure to acknowledge (and establish rates based on) both decreasing and increasing costs. The United States Supreme Court, in construing the Fifth Amendment mandates in conjunction with utility ratemaking, aptly concluded:

> Regulation may, consistent with the Constitution, limit stringently the return recovered on investment, for investors' interests provide only one of the variables in the constitutional calculus of reasonableness (citations omitted). It is, however, plain that the 'power to regulate is not a power to destroy,' (citations omitted) and that maximum rates must be calculated for a regulated class in conformity with the pertinent constitutional limitations. Price control is "unconstitutional if arbitrary, discriminatory, or demonstrably irrelevant to the policy the legislature is free to adopt." [*Permian Basin Area Rate Cases, supra*, 390 US at 769-770 (Emphasis added).]

The Commission has an obligation to facilitate DTE Electric's financial health for the benefit of its electric customers and shareholders.[17] Our Supreme Court has also stated that:

> Statutes will be construed in the most beneficial way which their language will permit to prevent absurdity, hardship or injustice; to favor public convenience, and to oppose all prejudice to public interests. [*Attorney General v Marx*, 203 Mich 331, 335; 168 NW 1005 (1918).]

Under well-established ratemaking law, rates for utility service are set prospectively so that the utility provides service, and its customers receive service at established rates, which are based on the estimated costs of providing that service, plus a reasonable return on the utility's investment. *ABATE v Public Service Comm*, 208 Mich App 248, 257-258; 527 NW2d 533 (1994). This is part

[16] MCL 460.11(1).

[17] *See, by way of example and not limitation*, MCL 460.6j(1); MCL 460.10(b); *Smith v Illinois Bell Telephone Co*, 270 US 587, 591; 46 S Ct 408; 70 L Ed 747 (1926). *Federal Power Comm, supra*, 320 US at 602; *Michigan Bell Telephone Co, supra*, 332 Mich at 37; *MichCon, supra*, 389 Mich at 633; *Michigan Bell Telephone Co v Engler*, 257 F3d 587, 594-96 (CA 6, 2001).

of the "regulatory compact," under which the utility dedicates its private property to serve the public, and correspondingly receives a reasonable return on the value of its private property. In *Board of Public Utility Comm'rs v New York Telephone Co*, 271 US 23; 46 S Ct 363; 70 L Ed 808 (1926), the United States Supreme Court explained that the just compensation safeguarded to the utility by the Fourteenth Amendment is a reasonable return on the value of the property used at the time that the property is being used for the public service. Rates that are not sufficient to yield that present return are confiscatory. 271 US at 31. To the extent that the utility might have earned sufficient revenue in the past, such past revenue cannot be used to sustain confiscatory rates in the future. *Id*. at 32. Thus, it would be unconstitutional for the Commission to use hindsight or otherwise base DTE Electric's rates on past events.

The Michigan Supreme Court has recognized that the Commission has only limited statutory authority, which does not include the authority to retroactively reduce rates. *Michigan Bell Telephone Co v Public Service Comm*, 315 Mich 533, 347; 24 NW2d 200 (1946). A lawfully established rate remains in force until altered by a subsequently established lawful rate. *Id*., at 544. A regulatory body cannot penalize a utility for collecting a rate during the period elapsing between the date of the order prescribing the rate and the date of the subsequent order reducing it. *Id.* at 543-44. Where the Commission establishes a reasonable rate in its legislative capacity, the Commission cannot later, in its quasi-judicial capacity, find that the utility violated the law because it charged that rate. *Id.* at 550-51.

The prohibition against retroactive ratemaking remains in effect and applies in this case so that rates may only be set prospectively. "[T]he essential principal of the rule against retroactive ratemaking is that when the estimates prove inaccurate and costs are higher or lower than predicted, the previously set rates cannot be changed to correct for the error; the only step that the MPSC can take is to prospectively revise rates in an effort to set more appropriate ones." *The Detroit Edison*

Co v Public Service Comm, 416 Mich 510, 523; 331 NW2d 159 (1982) (opinion by Fitzgerald, C.J.).

IV. TEST YEAR[18]

DTE Electric's projected test year is January 1, 2025 through December 31, 2025. The Company normalized and adjusted actual results from the historical test year ended December 31, 2022 to arrive at its filed projected revenue deficiency of approximately $456.4 million (Foley, 2T 80, 82, 89, 92; Vangilder, 6T 2811; Exhibit A-11, Schedule A1, line 11). That amount is adjusted to $446.1 million in this Brief (See Attachments A and B).

The only disagreement was by ABATE, which echoed its arguments from Case Nos. U-20836 and U-21297 against projected test years (Dauphinais, 6T 3369-76). The Company again disagrees because the use of projected test years is well established (Foley, 2T 183). For example, the Commission rejected ABATE's position in the Company's last rate case, recognizing that "the Commission's approval of projected test years is permissible under MCL 460.6a and challenges to the use of a projected test year have been well settled by the Court of Appeals" (December 1, 2023 Order in Case No. U-21297, p. 9, with footnote to Court of Appeals decisions). ABATE also tacitly concedes that its continued opposition to a projected test year does not merit serious consideration by otherwise using the projected test year in this case, and basing its proposed disallowances on that projected test year (e.g., York, 6T 3331).

For completeness, the Company further notes that MCL 460.6a(1) plainly states: "A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges." The January 1, 2025 – December 31, 2025 test year in this case is plainly a "consecutive 12-month period." In addition to Case Nos. U-20836 and U-21297, the

[18] See generally, Section II. History of Proceedings – *DTE Electric* – Foley, Vangilder; *ABATE* - Dauphinais, York.

Commission recognized MCL 460.6a(1)'s plain language in DTE Electric's prior two rate cases (U-20162 and U-20561) as it relates to the use of a projected test year, explaining in part:

> The statute contains no limitation on the future consecutive 12-month period, no requirement to use an historical test year, and no information or limitation regarding the relationship between the date of the application and the test year. The test year may be in the future, and the 12 months must be consecutive; those are the requirements of the statute. [Case No. U-20561, Order dated May 8, 2020, p. 11.]

RCG appealed from this decision, seeking to deviate from the plain statutory language, but the Court of Appeals affirmed, and our Supreme Court declined to hear the case. *In re Application of DTE Electric Co*, unpublished per curiam opinion of the Court of Appeals, issued December 21, 2021 (Docket No. U-353767), *lv den* 974 NW2d 192 (May 31, 2022). [19]

ABATE similarly posits a narrow definition of "known and measurable changes," which is apparently designed to effectively preclude the use of projections because the future is inherently uncertain (Dauphinais, 6T 3373). This policy argument lacks merit and relevance in light of MCL 460.6a(1)'s plain statutory language and the requirement that the courts and the Commission must apply that plain language, regardless of ABATE's disagreement with how our Legislature wrote it.[20] Also contrary to ABATE's suggestion that the Company's expenditures are not "known and measurable changes" to the historical test year (Dauphinais, 6T 3373), the Company provided ample testimony, exhibits, and discovery responses demonstrating that its projected costs are known (likely to occur) and measurable (projected with reasonable accuracy). (Foley, 2T 183).

[19] The Commission reached a similar conclusion in Case No. U-20162. The Court of Appeals affirmed and denied rehearing, and the Michigan Supreme Court similarly denied RCG's application for leave to appeal and reconsideration. *In re Application of DTE Electric Company to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued February 25, 2021 (Docket Nos. 349924 and 350008), *recon den* (April 19, 2021) *lv den* (November 2, 2021), *recon den* (January 31, 2022).

[20] *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"); *In re Complaint of Rovas Against SBC Michigan*, 482 Mich 90, 98; 754 NW2d 259 (2008) ("agencies cannot exercise legislative power by creating law or changing the laws enacted by the Legislature").

There is similarly no merit in ABATE's assertions that the use of projected test years "has caused and continues to cause customers to experience rate increases sooner because rates are being based on future projections," and "has resulted in higher rates for customers than if rates were based on the historical test year" (Dauphinais, 6T 3372). ABATE's arguments in favor of regulatory lag are contrary to MCL 460.6a(1). If our Legislature had intended to limit or eliminate projected test years as ABATE proposes (after years of other cases with projected test years), then it "surely could have said so."[21] Unless and until our Legislature re-writes the statute, it must be applied as written.[22]

ABATE's assertions are also inapt because in this case (as in prior cases) base rates are proposed for a future twelve-month period beginning when the Commission's order is expected. Thus, the new rates will match the costs approved by the Commission. This matching of costs and rates supports the timely recovery of costs, and helps ensure that the Company can continue making investments that benefit customers, such as improving reliability and transitioning to cleaner generation (Foley, 2T 183-84).

Timely recovery of capital investment and operating expenses means matching cost recovery to cost incurrence. Without the timely recovery of capital expenditures, the Company would have to consider re-timing the investments to a future period. If the disallowed expenditure is unavoidable, then the Company would have to consider re-timing capital investments elsewhere in its portfolio. Similarly, if operating expenses are disallowed but unavoidable, then the Company

[21] *Lash v Traverse City*, 479 Mich 180, 189; 735 NW2d 628 (2007); *People v McIntire*, 461 Mich 147, 160; 599 NW2d 102 (1999).

[22] *Di Benedetto, supra,* 461 Mich at 402. See also, *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); and *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").

would have to consider re-timing other spending to offset the disallowed (but unavoidable) cost (Foley, 2T 140-42).

Therefore, ABATE's argument against projected test years should again be rejected because it (1) is contrary to plain statutory language, (2) simply rehashes policy arguments that have been repeatedly rejected, and (3) is refuted by the massive record in this case (along with DTE Electric's Part III submission and voluminous responses to audit and discovery requests verifying the Company's projected costs.

V. RATE BASE[23]

A utility's rate base consists of the net amount of capital invested in plant, plus the utility's working capital requirements. DTE Electric's initially filed rate base for the projected test year was $22.108 billion, which consisted of $20.813 billion of net plant, and $1.295 billion of working capital (Vangilder, 6T 2812; Exhibit A-12, Schedule B1, column (d)).

Staff proposed a $140,976,000 decrease to $21,967,013,000 (Hecht, 6T 4885-86).

The Company made small adjustments to its originally filed rate base (see Attachments A and B). DTE Electric's Total Rate Base request as adjusted in this Brief for the projected test year is $22.1 billion, which consists of $20.8 billion of net plant and $1.3 billion of working capital.

A. Working Capital

As indicated above, DTE Electric supported a projected working capital amount of $1.295 billion. Staff proposed a reduction of $6,111,000 related to other accounts receivable (Hecht, 6T

[23] See generally supra, Section II. History of Proceedings – *DTE Electric* - Vangilder, Uzenski, Fix, Hatsios, Guillaumin, Lee, Milo, Davis, Kryscynski, Hill, Hartwick, Elliott-Andahazy, Deol, Steudle, Foley, Bellini, Farrell, Sharma; *Attorney General* -- Coppola, *ABATE* – York; *Staff* -- Hecht, Kindschy, DeCooman, Becker, Doherty, Mathews, Rogers, Boutet; *ITC* – Chindhade; *AG-MN* -- Alvarez, Stephens; *GLREA* -- Richter, *CEO* – Volkmann, *DAAO* – Koeppel, Makhijani; *MI-MAUI* -- Bunch; *Ann Arbor* – Stults, Naheedy, *MEIU* – Sherman.

4888). The Company accepts this adjustment. Working Capital also includes $9,933,000 for the Ludington regulatory asset (Exhibit A-12, Schedule B4, line 27, column (c)). The AG proposed that this regulatory asset be removed from working capital, asserting that issues concerning Toshiba's defective work at the Ludington Pumped Storage Plant are unresolved, so "the Company should not earn a return on the deferred amount until the Commission decides the appropriate amount of deferred costs that the Company should be allowed to recover," and then "the appropriate return can be calculated and included with the deferred amount for the period of time that the recoverable portions of the net costs were outstanding" (Coppola, 6T 3641).

The AG's proposal should be rejected because it would unreasonably take away the Company's ability to recover, in a timely manner, the financing costs related to costs incurred by the Company and recorded to a regulatory asset that the Commission approved in the May 18, 2023 Order in Case No. U-21310. The AG's position is also inconsistent with established practice for regulatory assets. Earning a return on a regulatory asset by including it in working capital is an accepted regulatory practice and consistent with the treatment of other working capital financed by the Company. Regulatory assets are generally included in working capital unless they have a separate recovery mechanism. None of the costs recorded to the Ludington regulatory asset are being recovered in the PSCR or through another mechanism. Thus, including the Ludington regulatory asset in working capital is appropriate, and the AG's proposal should be rejected (Uzenski, 6T 1561, 1568-69).

The Company included $5,784,000 of working capital for the Time of Day (TOD) program (Exhibit A-12, Schedule B4, line 37). The AG asserted that "[i]n neither filed testimony nor in its exhibits, did the Company provide any evidence that the costs incurred in 2022 and forecasted for 2023 were reasonable and prudent," and recommended that the Commission "remove the

$5,784,000 of working capital for the TOD program and the $1,693,000 of amortization expense from the Company's forecasted amounts for the projected test year" (Coppola, 6T 3646-47).

The Company disagrees because in Case No. U-21297, the Company provided the projected cost for the TOD project as $2.4 million for 2022 and $6.1 million for 2023, for a total cost of $8.5 million for the deferred asset. The December 1, 2023 Order in Case No. U-21297 approved the working capital and the related $1.7 million in amortization expense. In this Case No. U-21534, the Company provided actual costs of $2.0 million for 2022 and projected costs of $6.5 million for 2023, for a total cost of $8.5 million. Overall, there has essentially been no change from the $8.5 million that the Commission approved for deferral in Case No. U-21297, so the Commission should reject the AG's proposed removal of $5,784,000 of working capital and the associated $1,693,000 of amortization expense (Hatsios, 6T 2312-13).

The Company also projected a balance of $3,884,000 in a regulatory asset, representing the difference between the amount of incentive compensation related to operating metrics approved in Case No. U-20836, and the forecasted expense based on achieving the targeted results (Uzenski, 6T 1570; Exhibit A-12, Schedule B4, line 41, column (c)). The AG asserted that (1) there is no recoverable balance for 2022, (2) the balance for 2023 is a regulatory liability of $6.8 million, and (3) it is premature to establish a regulatory asset for anticipated results in 2024 (Coppola, 6T 3641-43). The AG also calculated a $6,792,000 regulatory liability, and asserted that there should be a $9,997,000 reduction to working capital (eliminate $3,884,00 regulatory asset and include $6,792,000 regulatory liability). (Coppola, 6T 3644-45).

The AG's proposal should be rejected because witness Coppola's calculation is inaccurate and inconsistent with the design of the approved incentive compensation tracker mechanism.[24] Company accounting expert Uzenski explained the flaws in the AG's calculations, concluding that the appropriate amount of the deferral of incentive compensation for 2022 and 2023 is a net regulatory liability of $5.998 million as of December 1, 2023 (2022 regulatory asset of $750,000, and 2023 regulatory liability of $6.748 million). (Uzenski, 6T 1561, 1571-74).

Also as further discussed in section VII. C. 12 (Employee Compensation) the AG's simplistic binary approach (either the target was met, or not) is also flawed because it fails 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 (Uzenski, 6T 1572; Fix, 6T 2901-2903; Exhibit A-35, Schedule Z1).

The AG further proposed to amortize her calculated $6,792,000 regulatory liability over five years, resulting in "$1,358,000 of negative amortization as a reduction to the Company's forecasted O&M expenses for the projected test year" (Coppola, 6T 3644-45). If the Commission were to agree with the AG's amortization proposal, then the annual credit to O&M should instead be $1.2 million. This would result in a 2025 ending balance of $4.799 million, and an average liability in working capital of $5.398 million. This is a $9.282 million reduction in working capital compared to the Company's originally filed position (Uzenski, 6T 1574).

[24] In Case No. U-20836, the Commission adopted the AG's proposed 40% disallowance of operating measures (November 18, 2022 Order in Case No. U-20836, p 301). 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." (*Id*., pp 301-302). In the Company's last rate case, the Commission continued the deferral treatment above or below the base amount, but lowered the base amount assuming the Company achieves approximately 52% of its targeted metrics (December 1, 2023 Order in Case No. U-21297, p 239).

B. Capital Expenditures

DTE Electric has made, or will make, approximately $2.6 billion of capital expenditures in the 2022 historical test year, $5.2 billion from the end of the historical test year to the beginning of the projected test year (January 1, 2023 through December 31, 2024), and $2.6 billion in the 2025 projected test year (Exhibit A-12, Schedule B5, line 13, columns (b), (e) and (f)). These expenditures should be approved because they are reasonable and prudent investments in DTE Electric's system, and are necessary for DTE Electric to maintain its safe and reliable system for generating and distributing electricity to its customers.

1. Energy Supply

Company witness Guillaumin explained and supported total Energy Supply capital expenditures of $459.4 million for 2022, $1,042.6 million for the 24 months ending December 31, 2024, and $460.4 million for the projected test year (Exhibit A-12, Schedule B5.1, page 1, line 13, columns (b), (e) and (f)). [25] 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 for the Company's generation (Guillaumin, 6T 1595-96).

Ms. Guillaumin provided an overview of expenditures for routine and non-routine projects as reflected on Exhibit A-12, Schedule B5.1, page 1 (6T 1601-1604), and described the major non-routine capital projects (6T 1605-33; Exhibit A-12, Schedule B5.1, page 2), and the major routine capital projects (6T 1633-34, 1643-90; Exhibit A-12, Schedule B5.1, pages 3-7). Company witness

[25] The Energy Supply business unit operates and maintains the Company's fleet of wind and solar assets, but the costs of those assets are managed in other proceedings. Therefore, this discussion about Energy Supply assets concerns fossil generation and energy storage assets, including hydraulic storage and Battery Energy Storage Systems (BESS). (Guillaumin, 6T 1585).

Lee further explained and supported the Company's capital expenditures and actions to comply with the Steam Electric Effluent Limitations Guideline (ELG) Rule and Coal Combustion Residuals (CCR) Rule requirements (Lee, 6T 2728-47).

The Company's Integrated Resource Plan (IRP) case anticipates that Monroe Units 3 and 4 will retire in 2028. [26] In Case No. U-21297, the Company explained that projected capital expenditures will be significantly reduced by reducing or eliminating capital projects that were previously-planned to support longer operations, and avoiding investments that will no longer be needed to comply with environmental requirements. [27] Ms. Guillaumin provided an update here, further explaining that after the initial filing of Case No. U-21297, nine projects were cancelled on Monroe Unit 3, with seven other projects being executed as previously planned. Recent unit equipment inspections and failures also triggered the Company to move forward with two capital projects that were not previously anticipated to be required under a 2028 retirement (Air Heater Cold-End Basket Replacement Project, and Horizontal Reheat Tube Replacement Project). The Company also determined that the turbine valve project should fully overhaul all eight governor valves based on age and condition of internal parts, and four throttle valves due to valve seats cracking and weld failures. Finally, the Company reduced the Unit 3 DCS project by about 40% to focus on only completing work scope critical for continued unit operations until unit retirement at the end of 2028 (Guillaumin, 6T 1635-36). She also further explained and supported the updates and projects (6T 1634-43).

Routine maintenance projects greater than $1 million for the Belle River and Greenwood power plants are listed on Exhibit A-12, Schedule B5.1, pp 6-7. The AG did not opine on the

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

[27] The Commission previously noted that the reduced costs were largely undisputed, and addressed the disputed items (December 1, 2023 Order in Case No. U-21297, pp 13-24).

projects, but instead simply applied inflation to a three-year (2021-2023) average of capital expenditures, and proposed a $30.1 million disallowance consisting of $13,270,000 of 2024 capital expenditures for Belle River (the AG did not dispute 2025), and $16.8 million ($8,585,000 in 2024; $8,223,000 in 2025) of capital expenditures for Greenwood (Coppola, 6T 3619-20).

The Company disagrees because the AG provided no engineering analysis, nor did she specifically dispute (or even evaluate) the Company's planned projects, which are needed to maintain safe, reliable, and environmentally-compliant plant operations. Instead, the AG relied entirely on the simplistic use of historical averages, which ignores the necessary work, including increased project work expected due to planned outage schedules. In the 2021-2023 timeframe used by the AG, Belle River only had one major maintenance outage, and Greenwood had a partial outage. In contrast, for 2024 and 2025, two major maintenance outages are planned for Belle River, and one full major maintenance outage is planned for Greenwood (Guillaumin, 6T 1722-1723).

Ms. Guillaumin further explained why planned outage schedules are an important consideration for projected routine capital maintenance, and other reasons causing the 2024-2025 Belle River and Greenwood routine capital expenditures to exceed their 2021-2023 historical averages:

> The Company's steam generation units are typically taken offline at least once every 3-5 years for several months in order to perform major maintenance. During these planned major maintenance outages, large capital projects are completed to keep the units running safely, reliably, efficiently, and environmentally compliant until the next major maintenance. This results in variability in annual spend levels, with some years being much higher than others, based on the amount and complexity of required power plant work, not by calendar year or funding utilized in past years.
>
> * * *
>
> Every major maintenance outage includes differing work activities and supportive capital projects. Project scope and required funding levels can increase greatly when major work on the turbine-generator and/or boiler key components is required. For example, the Company is replacing the low pressure (LP) turbines on

> Belle River Unit 2 in 2024 and Greenwood Unit 1 in 2025 due to industry-wide concerns with stress corrosion cracking as further discussed in my revised direct testimony [6T 1670-71, and 1684]. This turbine maintenance is routine in nature but infrequent as evidenced by this being the first time the LP turbines have been replaced in the history of the plants. The LP turbine rotors were original equipment and installed approximately 40 years ago. In total, each turbine replacement project exceeds $20 million. Infrequent but routine in nature, large capital maintenance projects, such as the replacement of the LP turbines, lead to lumpy annual capital expenditure levels. [Guillaumin, 6T 1723-24.]

Therefore, the AG's proposed disallowance based on a simplistic three-year average of historical spending should be rejected, and the Company's requested cost recovery should be fully approved.

The Company also seeks to recover $3.3 million for the Blue Water Energy Center (BWEC) Conference Room Building (Exhibit A-12, Schedule B5.1, page 6, line 145). The Commission previously did not include this project in rate base, reasoning that the Company did not support it sufficiently (December 1, 2023 Order in Case No. U-21297, pp 37-38). ABATE proposed that the Commission do so again (York, 6T 3354-55).

The Commission should now approve the costs because the Company further explained and justified the project in response to the Case No. U-21297 Order. In general, the project is needed for additional workspaces during routine and major maintenance activities because a large number of support personnel are onsite during these times. All Company power plants have either constructed or repurposed available space over the years to create large meeting spaces to accommodate workforce surges during routine and major outages or construction activities. This building was not required during initial construction of the plant because short-term rental trailers were utilized by the project construction firm (Kiewit) for hosting and onboarding the large workforce during project construction. The project is further supported by Exhibit A-34, Schedule Y1, which includes several discovery responses including an analysis of the BWEC Conference Room Building project versus other options including purchasing and renting trailers. This analysis indicates that the conference room project will save the Company over $10 million over the life of

the plant as compared to purchasing and renting trailers to support plant needs. Therefore, the Commission should approve the Company's requested recovery as sufficiently supported, and reject ABATE's proposed disallowance (Guillaumin, 6T 1699-1700, 1725-26).

Staff recommended a $21,333,494 reduction (net 2023 increase and 2024 decrease) for routine capital projects based on the difference between November 2023 and April 2024 actual expenditures compared to projected amounts in the Company's exhibits (Kindschy, 6T 5179-80), and a $5.1 million reduction for non-routine capital projects (Kindschy, 6T 5178 ($3,710,061); DeCooman, 6T 5052 ($1.366 million for blackstart projects, which are also discussed separately below)).

The Company disagrees because the variance between exhibit and actual project spends for those few months is not a proper metric for measuring project execution, nor an adequate projection of final project results. The end result of capital projects' scope and cost are important, not the month-to-month journey to reach project completion. Capital projects are managed on a total beginning-to-end basis, with monthly estimates developed to track project evolution and annual total budget targets. There can be monthly timing differences that can shift spending between months during project execution. Timing differences mean that work has been completed or will be completed sooner or later than initially forecasted. The Company expects that the portfolio of projects will meet the overall project spend as indicated in the Company's Exhibits (Guillaumin, 6T 1728-29, 1733).

Moreover, applying Staff's proposed monthly expenditure variance to all non-routine projects (instead of just the subset chosen by Staff), results in $123.6 million of actual expenditures for November 2023 through April 2024, which exceeds the $109.3 million projected in Exhibit A-12, Schedule B5.1, page 2 (see Exhibit A-34, Schedule Y2 for details). Thus, using Staff's approach

would result in increasing the Company's non-routine capital expenditures by $14.4 million.[28] Therefore, Staff's proposed disallowance based on the short-term spending variance of a subset of projects should be rejected (Guillaumin, 6T 1729).

Staff also "recommends a reduction of 15% for May-December 2024 of ($10,648,865) and a reduction of 20% in 2025 of ($28,451,121) for all PAT0 and PAT1 Routine Maintenance capital projects greater than $1 million on Exhibit A-12 Schedule B5.1 pages 6-7" (Kindschy, 6T 5181). Staff used the Association for the Advancement of Cost Engineering (AACE) International Cost Estimate Classification System, and reasoned that later (2025) work is at an earlier stage of development and further in the future, and therefore should have a higher disallowance factor (AACE Class 5, 20%) compared to near-term (2024) work (AACE Class 4, 15%). (Kindschy, 6T 5180-81). The Company disagrees because Staff essentially proposes to de-risk projects that have already been de-risked.

More specifically, Staff did not properly apply the AACE cost estimate classification system because Staff neglected that the Company's projects do not include contingency. The AACE guidelines state (as reflected in Staff Exhibit S-16.3, page 3, Note A) that: "The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical variation of actual costs from the cost estimate *after application of contingency . . . for the given scope*." (Emphasis added).

Staff's application of the AACE's 15% to 20% reduction factors to Company projects that have *already been de-risked by the removal of contingency* results in a far greater reduction than

[28] The Michigan Supreme Court has recognized that creating rates that recognize *reductions* in certain costs while ignoring the *increase* in other costs, violates the due process rights of utilities. The Court cited with approval the conclusions of a circuit court judge granting an injunction against such unlawful rates in *Michigan Consolidated Gas Company v Public Service Comm*, 389 Mich 624, 633; 209 NW2d 210 (1973) ("Certainly at first blush it would appear to anyone steeped in 'due process' considerations that it is grossly unfair to include certain items of decreased cost in rate determination while at the same time to exclude items of increased cost.")

the AACE method contemplates. Table 1 at Guillaumin, 6T 1732, further illustrates that proper application of the AACE method (to a project including contingency) produces an amount near the base project amount excluding contingency (which is what the Company is requesting in the first place). Staff's proposed additional reduction based on a misapplication of the AACE method is unsound and should be rejected (Guillaumin, 6T 1731-32).

Staff further reasoned that its proposed disallowances (15% for 2024, and 20% for 2025) are "reasonable given that the monthly actual amounts Staff received compared to the projections included in the Company's original filing are lower for January to April 2024" (Kindschy, 6T 5181). The Company disagrees with Staff's reliance on the variation between projected and actual spending over this short period. As discussed above, capital projects are managed on a total beginning-to-end basis, with monthly estimates only developed to track general project evolution and annual total budget targets. Short-term spending that is lower than forecast due to a timing variation does not indicate a reduction in future spending, but instead indicates that future spending will be higher than forecast due to spending milestones shifting to the future (Guillaumin, 6T 1728-29, 1733).

Therefore, Staff's proposed disallowances to projects that already exclude contingency based on a misapplication of the AACE method contrary to the AACE instructions, and short-term timing variances in project spending that do not support a reduction in future spending, should be rejected (Guillaumin, 6T 1733-34).

ABATE took issue with 2023-2025 capital expenditures for five North American Reliability Corporation (NERC) black start projects (York, 6T 3348; Exhibit A-12, Schedule B5.1, page 2, lines 37-39; and page 7, lines 225 and 231). ABATE recommended removal of $34.4 million of capital expenditures, reasoning that the Project Management Documents (PMD) were redacted, so parties could not independently review the projects (York, 6T 3351-54).

The Company disagrees because ABATE repeats its position from Case No. U-21297, where the Commission was "persuaded of the importance of these projects in maintaining grid security and that the information provided on this record is sufficient to justify recovery" (December 1, 2023 Order in Case No. U-21297, p 43). The Company properly protected the security-sensitive information in this case, just as it did in Case No. U-21297. Therefore, ABATE's proposed $34.4 million disallowance should be rejected (Guillaumin, 6T 1735). ITC also supported the Company's recovery and the protection of security-sensitive information (Chindhade, 6T 4753-55, 4757-59).

Staff recommended a "partial disallowance of $1,366,000 and $1,228,780 in 2023 and 2024 bridge period capital expenditures for three Blackstart Projects" (DeCooman, 6T 5054, referencing projects at Exhibit A-12, Schedule B5.1, page 2, lines 37-39, as reflected at DeCooman, 6T 5053). The proposed disallowances are based on variances between actual expenditures and the amounts projected in Exhibit A-12, Schedule B5.1, page 2.

Staff's adjustment for 2023 is inapt as discussed above regarding routine capital projects (Guillaumin, 6T 1728-29, 1733). For 2024, Staff reduced the Company's projections by 14% based on the difference between amounts forecasted in Case No. U-21297, and actual capital expenditures (Kindschy, 6T 5180-81). The Company disagrees because it is unreasonable to assume that because actual spending was less than forecast in the past, then future projections should be reduced. To the contrary, future spending is likely to be higher than the original forecast due to spending milestones shifting to the future. Staff also did not consistently apply its reasoning to projects where actual spending was higher than forecast. Therefore, Staff's recommended $1.2 million 2024 disallowance should be rejected (Guillaumin, 6T 1737. See also, 6T 1728-29, 1733). ITC also supported the Company's full recovery (Chindhade, 6T 4757-4759).

The Trenton Channel Battery Energy Storage System (BESS) project (Exhibit A-12, Schedule B5.1, page 2, line 41) concerns construction of a lithium-ion BESS at the recently retired Trenton Channel Power Plant, consistent with the Company's most recent IRP, Case No. U-21193. The Commission previously adopted Staff's partial disallowance (December 1, 2023 Order in Case No. U-21297, p 46). The Company now seeks additional cost recovery (Guillaumin, 6T 1631-1633).

Staff "recommends a partial disallowance of $1,612,000 and $8,298,000 in bridge period and test year capital expenditures" which is a "flat percentage adjustment to the non-contracted work" that "would adjust the bridge period non-contracted work by 10% of the total estimate, and the test year by 20%" (DeCooman, 6T 5061-62).

The Company disagrees. In addition to the lack of any explanation of how Staff arrived at 10% and 20%, Staff's proposed disallowances for "non-contracted work" apparently attempts to calculate expenditures that are not associated with contracts. Staff's calculation (Exhibit S-10.6), however, inconsistently includes line 8 (owner's engineer and expert support) even though this line item is listed as being subject to contract. Staff's calculation also includes lines 9 and 10 (project overheads and AFUDC), even though the majority of these expenditures are dictated by direct spend for contracts. Therefore, the Commission should reject Staff's proposed disallowances as unexplained (the 10% and 20%) and internally-inconsistent (using contract spend to attempt to calculate non-contract spend). (Guillaumin, 6T 1738-39).

The River Rouge Decommissioning project (Exhibit A-12, Schedule B5.1, page 2, line 25) is to fully decommission and remove all plant structures including waste products from the site. In this case, capital expenditures support achieving a cold, dark, dry status by the end of 2024. Project approval was received in January 2023. The Company will address and request the remaining

decommissioning expenditures beyond achieving a cold, dark, dry state in a future rate case (Guillaumin, 6T 1620-21).

ABATE recommended disallowing $4.4 million, reasoning that it is the difference between 2024 expenditures indicated on Exhibit A-12, Schedule B5.1, page 2, line 25, and $8.4 million indicated on a Capital Appropriation Request Form (CARF) retiming form (York, 6T 3350-51, citing Exhibit AB-2).

The Company disagrees because a closer look at the CARF retiming form (Exhibit AB-2, p 3) shows total authorized funding of $94.9 million for the project. This includes $48.3 million of projected expenditures in 2025. There is more than enough funding authorized and anticipated for this long-term project to cover the $4.4 million paperwork difference identified by ABATE. Therefore, ABATE's proposed disallowance should be rejected (Guillaumin, 6T 1739-40).

The Slocum Battery Pilot (Exhibit A-12, Schedule B5.1, page 2, line 40) is a pilot to replace the diesel-fueled generating units 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 (Guillaumin, 6T 1630-31). The Commission addressed this pilot previously, noting Staff's general support and following Staff's proposed partial disallowances (November 18, 2022 Order in Case No. U-20836, p 51; December 1, 2023 Order in Case No. U-21297, p 245).

Staff recommended that the Commission "disallow $2,177,871 in bridge period capital expenditures," which "removes the additional capital expenditures in project overheads identified in Exhibit S-10.3," reasoning that the Company did not adequately support the increase in overheads from Case No. U-21297 (DeCooman, 6T 5056-57).

The Company disagrees. Exhibit S-10.5 reflects that the Company explained that the increase in overheads was driven by increases in material and labor costs on which the indirect overheads are calculated and applied. Company witness Guillaumin further detailed why overhead charges changed between Case No. U-21297, and that overhead costs as a percentage of the total project cost remained consistent. Therefore, Staff's recommended $2.2 million disallowance should be rejected (Guillaumin, 6T 1741-42).

The Trenton Channel Seawall project (Exhibit A-12, Schedule B5.1, page 2, line 28) is required to restore the seawall's integrity at the Trenton Channel Power Plant site. The existing infrastructure is at its end of life and must be replaced to ensure the stability of the land surrounding the Detroit River riverfront. The City of Trenton also stipulated that the Company develop a pedestrian green path that provides access to the riverfront as part of the approved demolition permit for the plant, which was recently demolished in anticipation of construction of the Trenton Channel BESS, discussed above (Guillaumin, 6T 1743).

ABATE proposed a complete ($10,934,000) disallowance, reasoning that the Company provided an Appropriation Request document that does not support the level of expenditures in Exhibit A-12, Schedule B5.1 (York, 6T 3348, 3350, citing Exhibit AB-2, pp 1-2). The Company disagrees. In addition to the discussion above, ABATE's Exhibit AB-2, p 1, shows a signed appropriations request for $1.1 million, which supports design and engineering work. The Company has spent over $500,000 to support design and engineering work so far, and the full project is progressing as planned for a scheduled completion in 2025. There is no reason to expect that the project will not be completed, since the project is necessary and continuing. Therefore, ABATE's proposed $10.9 million disallowance should be rejected (Guillaumin, 6T 1744).

GLREA proposed that the Commission "should direct the Company to carefully consider the benefits of installing future BESS capacity in smaller, distribution-connected units, and that any

future BESS proposal should include an analysis of opportunities for distribution-connected BESS, and why that option was, or was not, selected by the Company" (Richter, 6T 4857-58).

The Company disagrees because the Order from the Company's last IRP case states: "In acquiring the renewable and storage resources . . . the Company will comply with the MPSC's Competitive Procurement Guidelines for Rate-Regulated Electric Utilities" (July 26, 2023 Order in Case No. U-21193, p 5). The Competitive Procurement Guidelines already require the open and transparent consideration and evaluation of distribution-connected resources, including different ownership structures and the benefits that different projects can provide, including distribution-level benefits. Therefore, no Commission action is necessary, and GLREA's proposal should be disregarded (Guillaumin, 6T 1745-46).

In summary, the projected capital projects and associated expenditures for the Company's Energy Supply units are required to support safety, regulatory compliance, environmental compliance, and reliability. Therefore, the Company's capital expense recovery should be fully approved.

i. Actions in Response to Steam Electric Effluent Limit Guidelines (ELG) Rule Changes

There appears to be no dispute on this topic. The following discussion is presented for context and completeness.

Company witnesses Guillaumin and Lee explained that the ELGs are national wastewater discharge standards that are developed by the Environmental Protection Agency (EPA), and that the EPA's regulations cover wastewater discharges from power plants operated by utilities. On October 13, 2020, the EPA finalized the ELG Reconsideration Rule, which revised some requirements from the 2015 ELG Rule to contain time-based options for complying with the updated rules for Bottom Ash Transport Water (BATW) and Flue Gas Desulfurization (FGD)

wastewater. Bottom ash transport waters cannot be discharged into the environment after December 31, 2025, from a coal-fired power plant if the plant plans to continue coal-fired operations past 2028. Regarding FGD wastewater streams, plants with FGD systems can comply with one set of limits by December 31, 2025, or comply with a more stringent set of limits by December 31, 2028, if the plant plans to continue coal-fired operations past 2028. The Reconsideration Rule did not alter fly ash transport water (FATW) discharge limitations, which continues with a December 31, 2023 compliance date (Guillaumin, 6T 1598; Lee, 6T 2729-30).

The Company has two options to achieve compliance for BATW and FGD wastewater: (1) design and engineer new technologies that are compliant with ELG requirements; or (2) pursue a compliance subcategory, one of which is to cease coal-burning activities, including either retiring the coal-fired unit(s), or converting the unit(s) to other fuels by December 31, 2028, in which case the existing standard limits already in effect for BATW and FGD wastewater discharges would remain in effect (Lee, 6T 2731).

In addition to the cease-coal-burning subcategory, the Reconsideration Rule also established Best Available Technology (BAT) standard discharge limits for FGD wastewater and finalized a Voluntary Incentive Program (VIP) subcategory. Under the VIP, companies may choose to meet more stringent effluent limits established by the EPA based on the model technology of membrane filtration or zero-liquid discharge. If a company chooses the VIP option, then the applicability date for FGD wastewater compliance will be December 31, 2028 (Lee, 6T 2731-32).

To establish compliance for either of the above-described subcategories, companies were required to submit a Notice of Planned Participation (NOPP) to their state permitting agency by October 13, 2021, with a second opportunity later being provided in 2023. Accordingly, on October 13, 2021, DTE Electric submitted 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 VIP at the Monroe Power Plant for FGD wastewater compliance. Also on April 27, 2023, the Company submitted a cessation of coal NOPP for Monroe Units 3 and 4 (Guillaumin, 6T 1599; Lee, 6T 2731, 2734-35).

DTE Electric's NOPP for the Belle River Power Plant indicated a commitment to cease coal-fired 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 new ELG-compliant bottom ash technology by the end of 2025 (Guillaumin, 6T 1599). [29]

At the Monroe Power Plant, the Company will achieve BATW wastewater ELG compliance by the end of 2025.[30] For Monroe Units 1 and 2, the Company has chosen a VIP technology to achieve FGD wastewater compliance by December 31, 2028. Monroe Units 3 and 4 are expected to retire by the end of 2028 under the Company's most recent IRP,[31] which will eliminate the units' production of FGD wastewater, and thereby eliminate the need to install FGD wastewater treatment systems on those units (Guillaumin, 6T 1600-1601; Lee, 6T 2736-37).

Any potential that the ELG rule might change in the future does not affect the Company's need to comply with the existing rule at this time, and the corresponding need to continue moving forward to meet these deadlines. For example, the EPA's Notice of rulemaking initiative states that the "EPA expects permitting authorities to continue to implement the current regulations while the Agency undertakes a new rulemaking" (Lee, 6T 2738). The law has not changed, and one can only

[29] At the Belle River Power Plant, fly ash is currently collected dry, so there are no FATW implications. The power plant was also constructed and operates without FGDs, so there is no FGD wastewater. The bottom ash is currently collected using transport water, however, and the ELG Reconsideration rule requires the Company to achieve compliance with BATW discharge requirements (Lee, 6T 2736).

[30] The Company plans to terminate the use of water for transport of bottom ash at the Monroe Power Plant, and replace it by installing a dry drag chain conveyor system. The project was approved by the Company in 2022, is fully underway, and will meet the required compliance date (Guillaumin, 6T 1600).

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

speculate that it might change at some time in the future.[32] In addition, other factors such as long lead times for equipment, construction seasons, and utilizing periodic outages make it critical that the Company moves forward to meet the required deadline (Lee, 6T 2738).

2. Midwest Energy Resources Company (MERC) and Fuel Supply

Company witness Milo supported DTE Electric's Midwest Energy Resources Company (MERC) and Fuel Supply capital expenditures for 2022 through 2025. The capital expenditures of $2.2 million for 2022, $2.9 million for January 2023 through December 2024, and $1.2 million for the projected test year (as shown on Exhibit A-12, Schedule B5.2), relate to maintaining safety, meeting environmental requirements, reliable operations, and/or replacement of end-of-life equipment. Spending is designed to maintain safe and environmentally-compliant operations, but otherwise minimize investment. The capital expenditures are unavoidable, reasonable and prudent, and necessary to MERC's coal transshipment capabilities and Fuel Supply railcar availability (Milo, 6T 1752, 1759-63; Exhibit A-12, Schedule B5.2, columns (b), (e) and (f)). Therefore, and as further discussed below, the expenditures should be approved.

In Case No. U-21297, 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 expected retirement schedule for Monroe indicated in Case No. U-21193, 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

[32] 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. 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).

pending a determination of the appropriate retirement schedule for that equipment." (U-21297, 6T 3462). The PFD essentially agreed. The Company took exception. The Commission relevantly stated:

> The Commission agrees that pending a full evaluation of a retirement plan for the MERC facilities and assets, given the approvals of the Monroe power plant retirement and Belle River conversion to natural gas, it is appropriate for the company to weigh the necessity and value of these projected investments against the cost it seeks to place on ratepayers, Therefore, the Commission finds the ALJ's recommended allowance for the recovery of the $2.7 million in historical [2021] costs and removal and deferral of the projected bridge and test year costs ($4.56 million and $2.5 million, respectively) to be appropriate. Should the company seek recovery of these costs in a future rate case, it shall include the evaluation of its MERC investments and retirement plan to identify avoidable expenditures as described in this order.
>
> * * *
>
> If the company seeks cost recovery of these expenditures in a future rate case, it shall include with its request an evaluation of the necessity of its proposed investments for the Midwest Energy Resource Company facilities and the associated value to ratepayers as well as an evaluation of retirement scenarios for this facility and whether these investments are avoidable. [December 1, 2023 Order in Case No. U-21297, pp 50, 371.]

Accordingly, Mr. Milo explained that 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. The railcar fleet is similarly critical to delivering the required large amounts of coal at the lowest reasonable cost (Milo, 6T 1754-55).

The Company's plan is to cease MERC transshipment operations at the end of 2026, which coincides with the projected end of coal deliveries to Belle River. The Company also plans to move up the railcar fleet's retirement date to 2032, consistent with the planned retirement of the last two coal-fired units at Monroe. MERC spending is limited to expenditures only on critical items that could stop operations if not addressed. Railcar fleet spending is limited to completing a decade-

long program (essentially to replace worn out components on railcars) in 2025, which is important to limit and/or avoid repairs with higher costs, and because the Company will use the railcars through the life of Monroe (with no expected capital expenditures from 2026-2032). Thus, the capital expenditures requested in this case are substantially reduced because of the retirement plans, and these requested amounts should be approved because they reflect costs that are unavoidable, and reasonable and prudent, to maintaining safe, environmentally-compliant, and reliable operations (Milo, 6T 1755-63).

3. Nuclear - Fermi 2

Company witness Davis described the operation of the Fermi 2 Nuclear Power Plant (Fermi 2) and supported Fermi 2's 2022 actual, as well as projected, capital expenditures through December 31, 2025. The Nuclear Regulatory Commission (NRC) has licensed Fermi 2 to operate through 2045. The capital expenditures (and O&M expenses discussed in section VII. C. 4) that Mr. Davis discussed throughout his testimony reflect reasonable and prudent measures to ensure the safe and reliable extended operation of Fermi 2 (Davis, 6T 1805-1806, 1854). In general summary:

The Company's 2022 nuclear capital expenditures totaled $257.8 million, as listed on Exhibit A-12, Schedule B5.3, page 1, line 11, column (b). The projected capital expenditures are $451.5 million for the bridge period ending December 31, 2024, and $215.9 million for the projected test year (Davis, 6T 1807-1808; Exhibit A-12, Schedule B5.3, page 1, line 11, columns (e) and (f)).

Routine and Small Projects (summarized on page 1, line 2, and listed on pages 2 and 3 of Exhibit A-12, Schedule B5.3) are capital expenditures associated with maintaining the various

assets that support Fermi 2's safe operation. Mr. Davis further discussed certain projects (Davis, 6T 1814-32. Exhibit A-20, Schedule J2 provides additional details for select projects).

Non-Routine and Large Projects (summarized on page 1, line 3, and further detailed on page 4 of Exhibit A-12, Schedule B5.3) are large capital projects that are necessary to maintain Fermi 2, and beyond normal routine capital expenditures (Davis, 6T 1832-33). Mr. Davis also discussed the expenditures and rationales for projects, and emphasized that none of the capital expenditures for the projects include contingencies (Davis, 6T 1833-49; Exhibit A-12, Schedule B5.3, page 4, lines 3, 4, 5, 6, 8, 9, 10, 11, 13, 14, 16, 17, 18, 21 and 22).

Mr. Davis also explained the timing of Fermi 2's plant refueling outages, and the components of Nuclear Fuel capital expenditures, which he supported as reasonable and prudent (Davis, 6T 1849-52; Exhibit A-12, Schedule B5.3, page 1, line 10).

Turning to proposed disallowances, as indicated above, Nuclear Generation projects support the safe and reliable operation of Fermi 2. The Company's 2022 capital expenditures totaled approximately $254.5 million, and the projected capital expenditures are approximately $339.5 million for the bridge period ending December 31, 2024, and $80.9 million[33] for the projected test year (Davis, 6T 1883, 1895; Exhibit A-12, Schedule B5.3, page 1, line 4, columns (b), (e) and (f)).

Staff and the AG proposed (with some overlap) unreasonable and imprudent reductions totaling approximately $181.4 million (approximately 70%) of the $263.6 million of capital expenditures for the 24-month period ending December 31, 2025. The proposals are based on unsound reasoning, as discussed below and further detailed in Mr. Davis' rebuttal testimony (6T 1883-1907) The Company's proposed expenditures are consistent with Fermi 2's history and continuing safe and reliable operations (Davis, 6T 1882-83).

[33] The correct amount for 2025 nuclear capital expenditures is $80.9 million (Exhibit A-12, Schedule B5.3, page 1, line 4, Column (f), not $80.1 million erroneously identified at 6T 1883 and 1895.

More specifically, Staff proposed approximately $46.5 million of disallowances (Kindschy, 6T 5182-85), consisting of (1) $15.7 million for the five-month period ending April 30, 2024 ($7,870,285 for Routine and Small Projects; $7,873,510 for Non-Routine and Large Projects); (2) $13.6 million for the seven-month period ending December 31, 2024 ($3,737,313 for Routine and Small Projects; $9,895,210 for Non-Routine and Large Projects); and (3) $16.2 million for the 12-month period ending December 31, 2025 ($8,490,015 for Routine and Small Projects; $7,683,968 for Non-Routine and Large Projects).

Staff reached these proposals by, again, comparing capital expenditure forecasts to actual expenditures, and then proposing disallowances based on project timing variances rather than any performance variance.[34] This is not a reasonable or reliable basis for projecting project costs. As discussed above in section V. B. 1 (Energy Supply), there is no sound basis for the Staff's assumption that projects are somehow systematically over-projected based on short-term snapshots of monthly spending. Instead, project portfolios are managed with timing variances that ultimately converge though the course of the project (Davis, 6T 1884-85).

For example, capital projects that are being implemented during a refueling outage must be managed as an integrated portfolio due to the highly-integrated nature of refueling outages. Company witness Davis further explained how this impacts individual projects:

> As I stated in my direct testimony [e.g., 6T 1812-13], DTE Electric manages incremental supplier personnel as a total. Individual projects must share these resources (such as scaffolds, insulators, radiation protection, etc.) and as an outage schedule updates, these resources are likely to be used by the projects in variance to the individual projections, yet the total resource usage remains controlled per total refueling outage capital projections. So, although individual capital projects may have variance, the whole of the capital projects implemented during the refueling outage will be on plan. [Davis, 6T 1886.]

[34] "Timing variance" means the work was completed or will be completed for the projected expenditure, but the projected expenditure's timing is sooner or later than originally forecast. "Performance variance" means the work was completed or will be completed at an actual expenditure that is higher or lower than projected (Davis, 6T 1885).

This is particularly relevant in demonstrating why Staff's proposed disallowances for the five-month period ending April 30, 2024 are improper. Mr. Davis discussed projects in the RF22 (Spring 2024) refueling outage in his direct testimony (e.g., 6T 1816), and he further explained in response to Staff:

> Witness Kindschy inappropriately treats timing variances for the 5-month period ending April 30, 2024, as permanent under-spends (performance variances). The Fermi 2 Refueling Outage 22 (RF22) was in progress during April 2024 which Witness Kindschy did not factor in her variance analysis . . . [recounting of direct testimony regarding project management and work safety omitted. See Davis, 6T 1810, 1849.]
>
> Nuclear Generation capital expenditures peak during the refueling outages. Capital expenditures in the months leading up to and through a refueling outage constitute most Nuclear Generation capital expenditures for the 24-month cycle. In fact, capital expenditures within the refueling outage are not homogenous with respect to schedule and can vary each outage. Generally speaking, capital expenditures during a refueling outage peak early in the refuel outage as that's when the material is being withdrawn from the warehouse and when the maximum number of incremental supplier personnel is on site, as the outage progresses incremental supplier personnel demobilize as the scope completes and daily capital costs trend lower, then capital costs peak again at the end of the refueling outage schedule as plant components such as the reactor vessel, the drywell and the turbine systems are returned to operations and associated capital costs are recognized. It is simply not possible to draw an accurate conclusion as to total capital expenditures at a nuclear plant by using monthly capital expenditures using only a portion of a refueling outage actual costs – which is what Witness Kindschy did with her 5-month period ending April 30, 2024 project schedule variance analysis [Davis, 6T 1887-88.]

Mr. Davis further explained that three months following an outage is generally sufficient time to review the capital expenditures. That is July 31, 2024 for RF22, which was completed in May of 2024. Exhibit A-47, Schedule LL1 updates the five-month capital expenditures in Staff's Exhibit S-16.6 to include May, June, and July 2024 expenditures, and shows that the total capital expenditures for the eight-month period were essentially on plan (Davis, 6T 1888-89; Exhibit A-47, Schedule LL1, page 1, column (j) shows actual expenditures of $160.4 million (line 4) and planned expenditures of $162.8 million (line 5)).

The Company reasonably and prudently completed RF22 (and Staff does not suggest otherwise), with capital expenditures that were essentially at the projected amounts after accounting for timing differences. Therefore, the Commission should not accept Staff's proposed $15.7 million reduction for the five-month period ending April 30, 2024. Staff's additional proposed disallowances also rely on timing differences, at least in part, so they should similarly be rejected (Davis, 6T 1889).

In addition to Staff's misplaced reliance on timing variances, Staff also incorrectly assumed that Exhibit A-12, Schedule B5.3 includes high-side over projections. Instead, the Company' projections exclude contingency, and are based on reasonable and prudent forecasting methods (Davis, 6T 1848, 1890. 1893-94). This is particularly relevant because, as discussed above in section V. B. 1 (Energy Supply), Staff misapplied the Association for the Advancement of Cost Engineering (AACE) International Cost Estimate Classification System to de-risk projects that are already de-risked.

Here, "consistent with Staff's approach to Steam Generation capital expenditures," Staff recommended a 15% reduction for May-December of 2025, and a 20% disallowance for 2025 (Kindschy, 6T 5183-84). Again, the AACE guidelines state (as reflected in Staff Exhibit S-16.3, page 3, Note A) that: "The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical variation of actual costs from the cost estimate *after application of contingency . . . for the given scope*." (Emphasis added). Staff's application of the AACE's 15% and 20% reduction factors to Company projects that have *already been de-risked by the removal of contingency* results in a far greater reduction than the AACE method contemplates (Davis, 6T 1891).

The AACE Process Industries Recommended Practices (Exhibit S-16.3, p 2) adds: "This addendum to the generic recommended practice provides guidelines for applying the principles of

estimate classification specifically to project estimates for engineering, procurement, and construction (EPC) work for the process industries." The process industries generally refers to oil refineries or chemical production, and EPC generally refers to larger turnkey construction projects. None of the capital expenditures reflected in Exhibit A-12, Schedule B5.3 fall in these categories (Davis, 6T 1892).

The AG proposed approximately $175.4 million of capital expenditure reductions consisting of: (1) $83.9 million for projects that will be placed into service beyond the projected test year (Coppola, 6T 3629); (2) $41.1 million for the Security System Computer and Plant Radio System projects (Coppola, 6T 3623, 3625); (3) $24 million for Natural Draft Cooling Towers, Document Management System Enhancements, and Remote Monitoring projects (Coppola, 6T 3628), (4) $6.5 million for the Sanitary System Replacement project (Coppola, 46), and (5) $20.0 million for nuclear fuel (Coppola, 6T 3627). The Company disagrees, as discussed below in the same sequence.

The AG's first proposal indicates only an apparent misunderstanding about accounting and/or the Company's exhibits. Projects that do not go into service during the projected test period have no impact on the Company's revenue requirement and deficiency (Uzenski, 6T 1567-68).[35] The Company added the in-service year projection to Exhibit A-12, Schedule B5.2, pp 2-4 to be transparent (Davis, 6T 1896. See also, 6T 1901-1902).

With regard to the Security System Computer project, the AG asserted that $28,230,000 should be disallowed, calculated as the amount that the $39,173,000 total cost exceeds the initial project cost ($9,948,000) plus 10% ($10,943,000). (Coppola, 6T 3623). With regard to the Plant

[35] To ensure that is the result, either the proposed disallowances for projects not going into service should be excluded from any reductions to rate base approved by the Commission, or a corresponding adjustment (reduction) in pre-tax AFUDC should be added to offset the removal of the projects from approved rate base (Uzenski, 6T 1568).

Radio System project, the AG similarly proposed a $12,830,000 disallowance, calculated as the amount that the $29,225,000 total cost exceeds the initial cost ($6,000,000) plus 10% ($6,600,0000). (Coppola, 6T 3625).

The Company disagrees because, in both cases, the AG asserted that there have been significant cost overruns based on an apparent misunderstanding of internal capital appropriations request forms for initial, *partial* appropriation approvals for baseline budgets to start the projects. Both projects were also previously presented to the Commission with higher numbers than the AG now uses for her calculations (U-20836, Exhibit A-12, Schedule B5.3 depicted the Security System Computer project at $14.8 million, and the Plant Radio System Project at $8.8 million; U-21297, Exhibit A-12, Schedule B5.3 depicted the Security System Computer project at $23.9 million, and the Plant Radio System project at $11.9 million). (Davis, 6T 1897-99).

The recently-authorized Security System Computer project appropriations (confidential Exhibit AG-9) increased the project's baseline budget to $39.2 million, and includes a description of nine items that changed relative to the original baseline budget. Company witness Davis further explained that:

> Most notable is the design and implementation of the Secured Owner Controlled Area (SOCA) building as these expenditures were uncertain in prior cases and excluded from previous calculations. Other updates to scope and schedule such as to use a more reliable technology for intrusion detection and to use recent operating experience to add a fully integrated system site acceptance test prior to in-servicing the project are reasonable and prudent updates to the project. As I state in my direct testimony staring at line 25 of [6T 1848], "some known scope with highly uncertain costs have expenditures excluded from exhibits (such as the Security Computer Replacement project) until such time the expenditures are capable of being identified with reasonable specificity to include in the exhibit[.]". [Davis, 6T 1899-1900.]

Similarly, the updated Plant Radio project appropriations (confidential Exhibit AG-10, p 4) describes why the project baseline budget increased to approximately $19 million, as Mr. Davis explained:

> Though, in the case of this updated Plant Radio project appropriation, the variance narrative could have provided additional context such that it was clear that "legacy issues with undersized wiring feeding the transformers of the UPS" means that when DTE Electric approved the initial baseline scope, the wires powering the interruptible power supplies (IPS) were assumed to have sufficient capacity to operate safely with the UPS units required for the Plant Radios; however field inspections and engineering calculations demonstrated that the wires would be insufficient to support the new Plant Radio System. As I have discussed, since Nuclear Generation and, in general DTE Electric, does not include contingencies in its rate case projections, establishing expenditure projections to replace wiring in the contingent event that the wire may not have sufficient capacity would be inappropriate. [Davis, 6T 1900.]

Due to this absence of contingency in the Company's projects (among other things), the AG is also incorrect in asserting that the project changes are "an excessive cost overrun and reflects an imprudent and unreasonable approach to project cost management" (Coppola, 6T 3622-23, 3625). The need for and use of contingency amounts at the individual project level and at the portfolio level is well understood in project management and portfolio management. This simply reflects that the world is an uncertain place. Yet in this rate case context, contingency is not included and the Company's case only includes in rates the work and expenditures the Company is highly certain it will incur. When contingencies arise, as indicated above, the Company is entitled to recover for these additional reasonable and prudent costs. They are not simply "cost overruns" as the AG asserts, nor should the Company's projections be subjected to Staff's inapt double de-risk reduction (no contingency, plus a percentage disallowance assuming there was contingency), as discussed above (Davis, 6T 1848, 1901).

The AG also proposed $24.0 million of disallowances for Natural Draft Cooling Towers, a Document Management System, and Remote Monitoring, asserting the Company is "following an unorthodox project management approach," and "should have identified project phases and timelines with a completion in-service date" (Coppola, 6T 3628).

The Company disagrees, noting that AG witness Coppola apparently envisioned a "phase-gate "approval process that the Company does not use, and which would be unreasonable and imprudent in this context. Mr. Davis explained in part:

> Nuclear Generation does not use the phase-gate approval process potentially envisioned by Witness Coppola as the majority of Nuclear Generation's capital work is asset replacement, not new construction, and though there may be a design change as I have discussed [at 6T 1827], design change at a nuclear power plant is to maintain configuration control, not to necessarily design new equipment. This means that a generalized understanding of project management that may apply in other fields, such as building construction, that includes steps such as (1) identify problem, (2) design solution, (3) solicit material labor contracts, and (4) execute work is not necessarily applicable to an operating nuclear power plant. [Davis, 6T 1903.]

Mr. Davis then gave an example of the necessary replacement of a pump motor (because the Fermi 2 license requires the pump motor) with the closest match available, which is slightly different than the original (Davis, 6T 1903-1904) and continued:

> A rigid adherence to a phase-gate approval process would result in decision-making paralysis because the new pump motor must be purchased well before the design would ever be completed. It is this dynamic that leads Nuclear Generation to sometimes use a "partial" appropriation and then follow up with a "full" appropriation to allow solicitation, procurement, design and implementation planning to all occur simultaneously at the initial phases, then as this initial work progresses, the full amount of the project becomes clearer and the full appropriation can be reasonably authorized. This approach is necessary, reasonable, and prudent. [Davis, 6T 1904.]

Projects such as the Natural Draft Cooling Towers and Remote Monitoring also do not follow project management principles as AG witness Coppola apparently envisioned because they are not "projects" as that term is used in the industry. Instead, they are capital maintenance activities, with little if any engineering requirements (Davis, 6T 1904-1905; Exhibit A-20, Schedule J2, p 28). The Document Management System similarly does not involve plant modifications or additional solicitations because the project is for the purchase and addition of modules to Fermi 2's existing document management system (Davis, 6T 1905-1906).

The Company seeks approximately $6.4 million of 2025 capital expenditures for the Sanitary System Replacement project (Exhibit A-12, Schedule B5.3, p 4, line 28, column (f)). The AG proposed a complete disallowance, reasoning that that the project "should have a project plan and timeline with a stated completion date and in-service date. The 'Annual' in-service date designation by the Company would imply an annual program, which does not appear to be correct for this project" (Coppola, 6T 3629).

To the contrary, as Mr. Davis indicated in his direct testimony and further explained on rebuttal, the project is intended to initiate and complete installation of the two-pump system in 2025, where the "annual" designation is used to convey that individual assets associated with the annual expenditures will be in service prior to year-end 2025. Additional expenditures to replace or reroute additional portions of the sanitary system may be required, but are not presently known, so the project expenditures "extend beyond the projected test period" (Davis, 6T 1847-48, 1906).

The AG further suggested that a disallowance is appropriate because the Company allegedly had an "inability or unwillingness to provide project timeline and current phase of development" (Coppola, 6T 3629). The AG's suggestion is unfounded because the AG's discovery asked for a specifically-formatted project status update (Exhibit AG-2, p 2). The Company's response (on the same exhibit) explained that Nuclear Generation does not status projects as a particular phase or in the manner requested. The project also has not started, and is not expected to start until 2025. Thus, there was also no historical spend, or 2024 spend for the project. There is only 2025 projected spend (as reflected by Exhibit A-12, Schedule B5.3, p 4, line 28). Therefore, there is no sound basis for the AG's proposed disallowance, and it should be rejected (Davis, 6T 1907-1908).

Exhibit A-12, Schedule B5.3, p 1, line 10 reflects the Company's historical and projected nuclear fuel expenses. The AG asserted that "[t]he 2025 nuclear fuel cost is out of line with historical levels by at least $20,017,000. Therefore, I recommend that the Commission remove this

amount from the Company's forecasted capital expenditures for 2025" (Coppola, 6T 3627). The AG based this recommendation on a discovery response (Exhibit AG-11), asserting that "the Company discusses variances in the number of fuel assemblies from outage to outage without addressing specifically the cost variance between 2023 and 2025, and states the calculation is in accordance with industry accepted software and rules, without providing further explanation or support for the calculation" (Coppola, 6T 3626).

The AG apparently misunderstood the discovery response and/or nuclear fuel projections, neglecting that a difference in the number of fuel assemblies results in a difference in costs. Exhibit AG-11, p 3, shows that Nuclear Generation projects to purchase uranium, enrichment, and fabrication to support 244 nuclear fuel assemblies in 2025 for introduction into Fermi 2's reactor core in RF23 (2026), as compared to 220 nuclear fuel assemblies in 2023 for introduction into Fermi 2's reactor core in RF22 (2024). All other factors being equal, 244 nuclear fuel assemblies costs approximately 11% more than 220 nuclear fuel assemblies (Davis, 6T 1908).

The Company's discovery response (Exhibit AG-11, p 3) further explained that nuclear fuel expense is, in part, "an outcome of a reasonable and prudent analysis of the nuclear fuel cycle components and contract terms applied to the projected Fermi 2 nuclear core design requirements, consistent with the Company's 2024 PSCR Plan U-21425." In that case, Company witness Wines discussed how nuclear fuel projections are developed, and the status of the Company's nuclear fuel contracts. The Commission's July 23, 2024 Order in Case No. U-21425 approved the Company's 2024 PSCR Plan pursuant to a settlement agreement to which the AG did not object (Davis, 6T 1908-1909).

There is similarly no sound basis for the AG's assertion that "the historical perspective shows that the Company has a propensity to overestimate the cost of nuclear fuel" (Coppola, 6T 3627). In addition to the prior discussion, the AG acknowledged that there was only about a 2%

difference in projected vs. actual ($122.7 million vs. $120.1 million) nuclear fuel costs in Case No. U-20836 for 2021 (Coppola, 6T 3626). Exhibit A-47, Schedule L2 further demonstrates that the Company has historically provided reasonable and prudent nuclear fuel projections. Line 9, column (k) shows the total nuclear fuel expenditures provided in Case No. U-20836 (2021, 2022, and 2023) were projected at $233.9 million, and were actually a nearly-identical $233.4 million (Davis, 6T 1909-10). There were similarly-small variations between projected and actual expenditures in other rate cases (Davis, 6T 1911-12).[36]

Thus, the Company's nuclear fuel expenditure projections are reasonable and prudent. Historical variances between projected and actual expenditures have been immaterial, and (contrary to the AG's suggestion) this history provides confidence that the Company's projections continue to be accurate in this case (Davis, 6T 1912).

The AG further argued that her approximately $20 million disallowance is justified as the difference between the Company's 2025 projection ($135.1 million) and $115.1 million, calculated as the average of costs in 2021 ($120.1 million) and 2023 ($110.0 million). (Coppola, 6T 3626).

The AG's simplistic average of fuel costs is invalid because it is contrary to how Fermi 2 operates, with a different number of fuel assemblies replaced in each refueling outage. Essentially, the longer the time between the end of one refueling outage and the start of the next refueling outage, the more nuclear fuel must be consumed to sustain the operating cycle, as Mr. Davis further explained using RF20, RF21 and RF22 as examples (Davis, 6T 1912-14).

[36] With regard to Case No. U-21297, the AG asserted that "[f]or 2023, the Company forecasted $117,421,000 for 11 months of costs for nuclear fuel, which annualized means it had forecasted $128,100,000 for the entire year" (Coppola, 6T 3626). Case No. U-21297 did use a bridge period ending November 30, 2023, but that case also had a projected test year ending November 30, 2024, in which only $0.2 million of nuclear fuel expenditures were projected, so there is no basis for the AG's annualized calculation (Davis, 6T 1910).

Based on all of these historical and operational reasons, the Company's requested nuclear fuel expenditures should be fully approved, and the AG's proposed $20 million disallowance should be rejected (Davis, 36T 1913-14).

In conclusion, the forecast of capital expenditures for Fermi 2 (depicted by Exhibit A-12, Schedule B5.3, page 1, line 11) accurately represents capital expenditures that can reasonably be expected to continue operation of nuclear assets of similar age and vintage. The projects and related capital expenditures reflect DTE Electric's commitment to ensure the safe and reliable operation of Fermi 2 through its current operating license expiration in 2045. These capital expenditures are reasonable and prudent given the regulations, goals and conditions under which Fermi 2 operates (Davis, 6T 1854). Therefore, the nuclear capital expenditures should be approved.

4. Distribution Operations (DO)

i. Overview

Distribution Operations (DO) focuses on the safe and reliable design, maintenance and operation of the Company's electrical distribution and subtransmission systems (often referenced collectively as "the distribution system"). (Kryscynski, 3T 298).[37]

DO capital expenditures totaled $1.5 billion in 2022 and are projected to be $3.14 billion for the 24-month bridge period ending December 31, 2024,[38] and $1.63 billion for the projected

[37] The DO organization consists of nine suborganizations: (1) Central Engineering; (2) Regulatory Strategy and Grid Modernization; (3) Scheduling & Construction; (4) Operational Technology; (5) Regional Customer Operations; (6) System Operation; (7) Emergency Preparedness & Response (EPR); (8) Tree Trimming; and (9) Substation Operations (Kryscynski, 3T 298-301).

A Project Management Office was recently created to better support the increasing construction for grid investments. The DO project organization merged with DTE's Major Enterprise Projects (MPE) group to consolidate project management expertise in one group, which is responsible for management and execution of the majority of Strategic Capital projects and programs for DO, as well as large investment projects for other areas of DTE (Kryscynski, 3T 301).

[38] The Company agrees with the AG's proposed removal of $25,202,000 of 2023 Base Capital expenditures based on 2023 actual expenditures being less than the forecast by that amount (Coppola, 6T 3617; Hill, 6T 3086-87).

test year (Kryscynski, 3T 317; Exhibit A-12, Schedule B5.4, page 1, line 23, columns (b), (e), and (f)).

Much of DTE Electric's distribution equipment is relatively aged, with 8 of the 18 asset classes having an average age at or near the equipment life expectancy (Kryscynski, 3T 306-309). The capital investments (discussed here) and O&M expenses (discussed in section VII. C. 5) are necessary to achieve the Company's goals of providing safe, reliable and clean 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 (Kryscynski, 3T 317).

AG-MN witnesses Alvarez (6T 3931) and Stephens (6T 3992), and Ann Arbor witness Stults (6T 4248) suggested that all-weather system-wide reliability is not showing an improving trend, despite recent increases to investment. The reason is that, at the macro level, volatile weather conditions greatly influence system-wide all-weather System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). Many customers are seeing reliability improvements from investments, but the Company continues to face three primary challenges going forward: (1) an increase in the number of high wind speed days, which adds additional stress to the already-aged fleet of equipment and provides more opportunities for failures; (2) the system continues to get older, which requires continuing investments to decrease the rate at which the Company's assets are aging; and (3) the Company is early in its journey to stabilize and rebuild the grid, which requires increased and sustained investments to improve and then maintain reliability (Kryscynski, 3T 313-17, 399-400).

The Company has two broad categories of DO-related capital expenditures: (1) Base Capital, and (2) Strategic Capital. Base Capital programs include work that the Company is required

to perform as part of normal business activities. There are two sub-categories within Base Capital: (1) Emergent Replacements (expenditures to recover from interruptions in service (e.g., due to storms, and equipment failures at substations, etc.) to address immediate safety concerns, or return the system to normal operating conditions, and which are reactive in nature; and (2) Customer Connections, Relocations & Other, which are planned expenditures to address customer requests for new or upgraded service connections, or to relocate equipment in response to third-party requests (*e.g.*, MDOT). Details of these subcategories are included in Exhibit A-12, Schedule B5.4, pages 3 to 12, with more detail in Exhibit A-23, Schedule M4 (Kryscynski, 3T 329; Hill, 6T 3033).

Company witness 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 and outages that occur during storms);[39] (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);[40] and (3) Substation Reactive (investments required to perform emergency replacements for substation equipment). (Hill, 6T 3034, 3041, 3045).

ii. Emergent Replacement – Storm and Non-Storm

Expenditures in Storm and Non-Storm Emergent are incurred to support field activities under eight work types: (1) Emergency Job; (2) Critical Infrastructure Customer; (3) Hazards; (4) Multiple Customer Outage; (5) Police/Fire; (6) Public Safety Concern; (7) Single Customer Outage; and (8)

[39] A storm is defined as greater than 760 customer outage events (when customers are left without power) impacting greater than 200 circuits (Hill, 6T 3034).

[40] Non-storm conditions are defined as fewer than 760 customer outage events for the entire system (Hill, 6T 3041).

Single Customer Problem (Hill, 6T 3047). Table 3 (at Hill, 6T 3048) provides descriptions for each category.[41]

Table 3. Storm and Non-Storm Work Category

Category	Description
Emergency Job	Non-outage events of the highest priority. These events are restricted to situations where the health and safety of a person are at imminent risk such as a person contacting the Company's electrical equipment, being trapped in a vehicle, building, or elevator due to power failure, downed wires, broken poles, etc.
Critical Infrastructure Customer	Outages affecting hospitals, schools, water and wastewater systems, or other critical infrastructure
Hazards	Non-outage events reported by customers to alert the Company of a potentially hazardous situation due to a sparking wire, broken pole, pole-top fire, and/or a tree or branch resting on a wire
Multiple Customer Outages	Outage events affecting more than one customer on a circuit. Events are created by the Outage Management System (OMS) prediction engine, which uses customer calls, AMI meter data, and the Company's network model to determine the size and extent of an outage. These outages can be caused by weather, trees, animals. public interference (e.g. vehicle accidents), and equipment failures and can involve concerted restoration efforts from overhead, underground, and substation personnel to restore power
Police/Fire	Non-outage events reported by a police or fire department. These events are created when police or fire personnel use their unique PIN number through one of the Company's reporting channels to report an event such as downed power line on a structure or a fire
Public Safety Concern	Non-outage events reported by customers where a primary or secondary wire is believed to have fallen and may pose a safety risk
Single Customer Outage	Outage events that affect a single customer through the same inputs as a multiple customer outage
Single Customer Problem	Non-outage events affecting a single customer that are not outages but can include power quality issues, such as low voltage or flickering lights, or downed service drops where a customer still has power

(Hill, 6T 3048)

The Company forecasts Storm expenditures of approximately $282 million for 2023, $244 million for 2024, and $251 million for 2025 (Hill, 6T 3034; Exhibit A-12, Schedule B5.4, page 1, line 3, columns (c), (d), and (f)). The 2024 and 2025 forecasts are based on a five-year (2018-2022) inflation-adjusted historical average, consistent with the methodology approved in the Commission's Orders in Case Nos. U-20162, U-20561, U-20836 and U-21297. The 2023 expenditures were higher

[41] The Company agrees with Staff's recommendation (Duell, 6T 5147) to improve descriptions of the work performed under Emergent Replacements Storm (Hill, 6T 3087).

than the five-year (2018-2022) inflation-adjusted average because 2023 included five catastrophic storms, including the most damaging winter ice storm in Company history, and a summer storm event that included heavy damage from six tornados (Hill, 6T 3034-35. See also, 6T 3036-41 for further details on 2023's catastrophic storms).

Non-storm investments are tracked in four categories: Emergent, Reactive, Corrective, and Environmental. Table 1 (at Hill, 6T 3043) provides descriptions and examples of each subcategory. The Company forecasts non-storm investments of approximately $207 million for 2023, $220 million for 2024, and $227 million for 2025 (Hill, 6T 3043-3044; Exhibit A-12, Schedule B5.4, page 1, line 4, columns (c), (d), and (f)). The 2024 and 2025 forecasts are based on a five-year (2018-2022) inflation-adjusted historic average, consistent with the methodology approved in the Commission's Orders in Case Nos. U-20162, U-20561, U-20836, and U-21297. The 2023 non-storm forecast is the same as the five-year inflation-adjusted average ($207 million) due to several factors including: (1) global supply chain issues and raw material shortages that resulted in higher material costs; (2) the grid is facing reliability and resiliency challenges posed by aging equipment and stronger and more frequent storms, so the Company has responded with a greater emphasis on replacing old, outdated equipment with equipment that has higher technical standards instead of merely repairing the failed equipment, which improves system resiliency and avoids the need to repeatedly repair the same asset; (3) upgrading to stronger, higher specification materials (for example, higher rated class poles and using fiberglass crossarms instead of wooden crossarms) which increases restoration costs, but improves reliability, resiliency, and safety; (4) proactive storm preparation and resource ramp-up in anticipation of extreme weather; and (5) increased use of higher-cost contractor labor (Hill, 6T 3043-44. See also, Hill in Case No. U-21297 at 5T 2743-52).

Emergent Replacement investments, Storm and Non-Storm, are essential to providing safe (e.g., responding to downed wires) and reliable power to customers, so these expenditures should be

approved. The importance cannot be overstated because deferral of this work increases the likelihood of the public being exposed to potential public hazards (e.g. downed wires), increases the frequency and duration of power outages, reduces grid resiliency, poses risks to the electrical system of additional equipment damage resulting in further power outages, and could leave critical equipment in abnormal conditions that could make it susceptible to damage in subsequent storms (Hill, 6T 3044-45).

AG witness Coppola recommended that the Commission "remove $24,526,000 for 2024 and $28,557,000 for 2025 from the Company's forecasted capital expenditures" for emergent replacements (Coppola, 6T 3603) for three reasons that all lack merit, as discussed below.

First, witness Coppola agreed with the five-year average, but asserted that the Company's normalization adjustment "is simply an unsupported fabrication to inflate historical costs to arrive at an adjusted historical base and to then further inflate those costs for future years with projected inflation factors" (Coppola, 6T 3601). To the contrary, prior years' expenditures must be expressed in a constant-dollar denomination (in this case, 2022 dollars, consistent with the historical test year) because the value of a dollar decreases over time due to inflation. Omitting the adjustment would understate the amount of capital required to do the same scope of work in future years (Hill, 6T 3066-67).

The Commission previously (1) approved the Company's normalization practice (May 8, 2020 Order in Case No. U-20561, p 86), (2) agreed with, and found appropriate, "the 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" (November 18, 2022 Order in Case No. U-20836, p 63), and (3) most recently "reject[ed] the Attorney General's inflationary adjustment and finds that DTE Electric has computed the historic average in a manner consistent with Case Nos. U-20836 and U-20561" (December 1, 2023 Order in Case No. U-21297, p 76). The Company's practice of adjusting historic years to derive a baseline expressed in current dollars is

also consistent with the constant-year method (inflation-adjusted values), which the U.S. Department of Defense recommends as a best practice for estimating, comparing, and reporting (Exhibit A-52, Schedule QQ1, December 2021 U.S. Department of Defense Inflation and Escalation Best Practices for Cost Analysis). Therefore, the Commission should maintain its position from past cases and again reject the AG's contrary position (Hill, 6T 3068-70).

Second, Witness Coppola also referenced his O&M discussion disagreeing with the Company's use of "blended" (labor and non-labor) inflation rates and asserted that "the Commission previously rejected the use of blended inflation rates" (Coppola, 6T 3601). Witness Coppola neglected to consider that the Commission previously adopted the Company's proposed composite inflation rates (November 18, 2022 Order in Case No. U-20836, p 258. See also December 1, 2023 Order in Case No. U-21297, p 193). The use of a composite rate continues to best reflect the inflationary pressures faced by the Company, since the Company's labor costs are driven by collective bargaining agreements with unionized employees (Foley, 2T 174). See also the further discussion in section VII. C. 1 (O&M Inflation).

Finally, Witness Coppola further asserted that the Company "did not provide an analysis in this rate case of the offsetting effects of significant distribution capital investments on inflationary pressures on Emergent Replacements" (Coppola, 6T 3601). To the contrary, Exhibit A-12, Schedule B5.4, page 1, line 6, columns (e) and (f) show reductions in Emergent Replacements of $20,819,951 for 2024, and $21,435,815 in 2025. These savings are based on strategic capital investments and the tree trim surge program, calculated using the Company's reliability model. The Company provided the calculations as a workpaper with direct testimony (Kryscynski, 3T 366; Hill, 6T 3035, 3071; Exhibit A-52, Schedule QQ3).

ABATE proposed a $122.882 million disallowance (not broken out by period) for emergent replacements based on a four-year (2018-2020 and 2022) average (York, 6T 3358-59), reasoning

that "[w]hile the five-year average has historically been approved by the Commission, it is inappropriate to rely on a five-year average in this case. Specifically, 2021 data should not be included in the historical average in this case, as it was an abnormal year in terms of storm activity" (York, 6T 3357). The Company disagrees because ABATE's selective exclusion of 2021 undermines the intent of using a five-year average to account for variability in weather. The Company acknowledges that the storms in the summer of 2021 were historic, but that does not mean that severe weather events will not occur again, as reflected for example by the Company experiencing the worst ice storm in its history plus six summer tornados in 2023, as discussed above. The Commission has also repeatedly approved the five-year average, recognizing increased climate variability over recent years (November 18, 2022 Order in Case No. U-20836, p 63; December 1, 2023 Order in Case No. U-21297, p 76). Therefore, ABATE's proposed selective four-year average should be rejected, and the Commission should continue to use a five-year average (Hill, 6T 3036-41, 3072-74).

ABATE's proposed disallowance was also based on the proposition that the Real GDP Chained Price Index should be used to project inflation on base capital (York, 6T 3358-59). The Company disagrees because the CPI-Urban is a well-established and widely used measure of inflation, and ABATE does not show that the Real GDP Chained Price Index is superior to the CPI-Urban in projecting utility-specific non-labor costs. For example, ABATE witness York discussed "customer substitution,"[42] but it is not apparent how this would be relevant for utility costs.

[42] ABATE witness York asserted: Each year, the basket of goods and services is updated to reflect what people are actually buying. This is unlike the CPI, which uses a fixed basket for a set period. This makes the Real GDP Index more responsive to consumer substitution – if prices of certain goods rise, people might switch to less expensive alternatives, and the index will reflect that change. In addition, the CPI can be heavily weighted by the cost of medical expenses, which is not reflective of the cost of utility expense. [York, 6T 3342.]

Therefore, ABATE's inflation alternative should be rejected (Foley, 2T 175-76; Hill, 6T 3075). See also the discussion in section VII. C. 1 (O&M Inflation).

iii. Substation Reactive

Substation Reactive investments are tracked in four subcategories: Major Equipment, Minor Equipment, Transformers & Regulators, and Non-Electrical Equipment. Table 2 (at Hill, 6T 3045) provides descriptions and examples of each subcategory. The Company forecasts expenditures of $42 million for 2023 (lower than the five-year (2018-2022) inflation-adjusted average of $46 million), and $49 million for 2024, and $50 million for 2025, based on the five-year inflation-adjusted average (Hill, 6T 3046; Exhibit A-12, Schedule B5.4, page 1, line 5, columns (c), (d), and (f)). It would not be reasonable or prudent to defer Substation Reactive work to replace critical grid equipment that has failed because when substation equipment fails, thousands of customers can be left without power for extended periods of time (Hill, 6T 3047).

Table 2. Emergent – Substation Reactive Description

Category	Description	Example
Substation Reactive- Major Equipment	Replacement of the Company's substation equipment classified as major equipment	**August 2022, Twelve Mile Substation** • Fire led to catastrophic failure and complete loss of substation • Company deployed portable equipment including a substation and multiple generators
Substation Reactive – Minor Equipment	Replacement of the Company's substation equipment classified as minor equipment	**April 2022 UNVIL Substation** • 40kV insulator broke free • Replaced three 40kV insulators
Substation Reactive – Transformers and Regulators	Replacement of substation transformers and regulators	**October 2022, Middlebelt Transformer 2** • 40-year old transformer failed internally causing outages • Load switched to another transformer for two days until change of transformer complete
Substation Reactive – Non-Electrical Equipment	Replacement of substation retirement units/assets not directly related to generation or transmission of electricity	• Control house HVAC heating to remove condensation which can erode equipment • Fence/gate repairs which are mandated by NERC

(Hill, 6T 3045)

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). Accordingly, the Company modified its accounting system to begin to track these expenditures and retrained its workforce to be able to separate expenditures related to imminent failures (Hill, 6T 3048-49).

iv. Customer Connections, Relocations & Other Capital Investments

Customer Connections, Relocations & Other Capital Investments are also reasonable, prudent, and should be approved. 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. The Company forecast 2024 and 2025 expenditures using a three-year inflation-adjusted average as consistent with the Commission's Order in Case No. U-21297, with two exceptions for discrete projects (I-375 relocations, and Incremental Infrastructure for EV). (Hill, 6T 3049-50. See also Kryscynski, 3T 331-32, and Hill, 6T 3050-58 for a further discussion of the sub-subcategories and other details).

For Electrical System Equipment, the AG proposed disallowances of "$3,153,000 for 2024, and $3,456,000 for 2025" (Coppola, 6T 3612). For General Plant, Tools & Equipment and Miscellaneous, the AG proposed disallowances of "$1,758,000 for 2024 and $1,862,000 for 2025" (Coppola, 6T 3613). AG witness Coppola again disagreed with the Company's use of a normalization adjustment, stating "[t]his is the same problem discussed above with Emergent Replacements, where the Company improperly inflates actual historical capital expenditures to create a larger cost base on which to add future inflation adjustments" (Coppola, 6T 3604)

The Company disagrees, as discussed above in response to the AG regarding Emergent Replacements (which is incorporated by reference). Prior years' expenditures must be expressed in a constant-dollar denomination (in this case, 2022 dollars, consistent with the historical test year) because the value of a dollar decreases over time due to inflation. Omitting the adjustment would understate the amount of capital required to do the same scope of work in future years. The Commission also previously approved the Company's normalization practice for emergent replacements (May 8, 2020 Order in Case No. U-20561, p 86; December 1, 2023 Order in Case No. U-21297, p 76). The Company's practice of adjusting historic years to derive a baseline expressed in current dollars is also consistent with the U.S. Department of Defense best practices (Exhibit A-52, Schedule QQ1, December 2021 U.S. Department of Defense Inflation and Escalation Best

practices). Therefore, the Commission should not adopt the AG's reasoning or resulting disallowances (Hill, 6T 3066-70, 3077-78).

For Customer Connections and New Growth, the AG proposed a disallowance of $14,453,000 for 2024, and an increase of $3,405,000 for 2025, based on calculations that (1) removed Utility Make Ready (UMR) expenditures, (2) then calculated the 2021-2023 average annual expenditures (without historic inflation adjustments), and (3) applied Michigan housing starts forecasts of -3.8% in 2024, and +10.8% in 2025 (Coppola, 6T 3607).

The Company again disagrees with the AG's opposition to expressing prior years' expenditures in a constant-dollar denomination. As discussed above, it is necessary to avoid understating the dollars needed to perform work in the future due to the decreasing value of a dollar and is consistent with past Commission decisions and U.S. Department of Defense best practices, as discussed above (Hill, 6T 3066-70, 3077-78, 3080).

The AG's use of Michigan housing starts forecasts is also inappropriate because Customer Connections and New Growth includes activities beyond connecting new homes, such as customer-requested upgrades, accommodating business development, and resolving circuit loading issues, which are not directly tied to residential housing starts. Therefore, the Company's methodology of using a three-year inflation-adjusted forecast is reasonable and prudent, and the Commission should reject the AG's proposed disallowance (Hill, 6T 3080).

The AG also proposed additional disallowances of "$3,734,000 for 2024 and $10,173,000 for 2025" for Customer Connections and New Growth associated with Utility Make Ready (UMR) projects supporting electric vehicle (EV) adoption (Coppola, 6T 3609). The Company disagrees and supports ensuring that the distribution grid is ready for EV adoption (Hill,6T 3081). See also the detailed discussion in section VIII. C (Electric Vehicle Pilots - Charging Forward).

Relocations includes the I-375 Relocation Project. MDOT notified the Company that it needs to relocate distribution infrastructure currently located in the I-375 below-grade freeway corridor, which will be replaced with a grade-level boulevard (Hill, 6T 3052-53; Exhibit A-12, Schedule B5.4, p 7, line 37). The AG proposed complete disallowances of "$25 million for 2024 and $8 million for 2025," reasoning that "MDOT is known for establishing initial plans and later delaying projects. Although the Company may have done some design and engineering work in 2023 with the $5.9 million budgeted, it is unlikely that it will spend the $25 million forecasted for 2024 or the $8 million forecasted for 2025. It is premature and imprudent to include those large amounts in rate base in this rate case" (Coppola, 6T 3611).

The Company disagrees because it has received a notice to vacate from MDOT and must proceed with the work (Hill, 6T 3083). It is unreasonable for the AG to assume that the entire project will be delayed so that no work will be performed in 2024 and 2025. The Company's latest forecast, which accounts for currently known project delays, is that $8,842,825 will be invested in 2024, and $13,802,315 will be invested in 2025. Therefore, the AG's proposed complete disallowance should be rejected, and it would be reasonable and prudent to approve recovery based on the Company's latest forecast (a reduction of $16,157,175 for 2024, and an increase of $5,802,315 for 2025). (Hill, 6T 3083-84).

v. Strategic Capital

Strategic Capital projects and programs include work that the Company performs to improve safety, reliability, operability, grid automation, and modernization. The Company proposes to invest $827.3 million in strategic programs and projects in the projected test year (Exhibit A-12, Schedule B5.4, page 1, line 22, Column (f)). These investments are subcategorized into three investment pillars:

1. ***Infrastructure Resilience and Hardening***. These projects and programs focus on near-term grid infrastructure investments to harden the system against an increasing frequency and severity of high winds and storms, address frequent outage circuits, and replace damaged and/or defective infrastructure. Exhibit A-12, Schedule B5.4, page 13 and Exhibit A-12, Schedule B5.4.8 provide investment details, with additional details at Exhibit A-23, Schedule M5.

2. ***Infrastructure Redesign and Modernization***. These projects and programs focus on fundamentally rebuilding and modernizing the grid to support customers' evolving needs, with goals of adding capacity and operational technology, while hardening the grid to enhance safety, reliability and resiliency, including investments such as conversion of the 4.8kV system and upgrades to the subtransmission system. Exhibit A-12, Schedule B5.4, pages 14-16 provide investment details, with additional details at Exhibit A-23, Schedule M6.

3. ***Technology & Automation***. These projects and programs are tightly linked to the grid modernization process, with technology investments benefitting customers through improved reliability, operability, and safety. Exhibit A-12, Schedule B5.4, pages 17-18 provide investment details, with additional details at Exhibit A-23, Schedule M7 (Kryscynski, 3T 329-38; Hartwick, 4T 632-33; Elliott Andahazy, 4T 911-12; Deol, 5T 1136-39, Steudle 6T 2987-91).

ABATE 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 reduction of $613.586 million relative to the amount proposed by the Company" (York, 31).

The Commission previously rejected ABATE's proposal for similar adjustments (December 1, 2023 Order in Case No. U-21297, p 94). ABATE neglects that 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.[43] Also, capital expenditures on projects that will not be in service during the projected test period do not have a current revenue requirement. 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). Therefore, the Commission should again reject ABATE's proposed disallowance for projects with in-service dates beyond the projected test year (Hartwick, 4T 857; Elliott Andahazy, 4T 1065; Deol, 5T 1268; Uzenski, 6 T1509, 1531, 1567-68). [44]

AG-MN witness Alvarez suggested that there are shortcomings in the Company's strategic capital governance. He divided distribution capital investments into defined strategic capital projects (for which he found no deficiency) and strategic capital programs, for which he suggested perceived deficiencies in the Company's planning and cost tracking. He specifically asserted that the Pole and Pole Top Maintenance and Modernization (PTMM), 4.8kV Hardening, and Distribution Automation (DA) programs "appear to be managed only at a program level as opposed to project level. The annual 4.8kV circuit conversion budget likewise appear to be a large pot of money from which DTE's distribution team can use to fund various conversion projects . . . with

[43] 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).

[44] If the Commission were to accept ABATE's proposition, then the impact could be material, and the Commission should order a corresponding adjustment (reduction) in pre-tax AFUDC to offset the removal of projects from approved rate base (Uzenski, 6T 1568).

no telling exactly how many circuit miles customers can expect will be completed, or DA devices customers can expect will be installed, or the capacity or reliability improvements that will be achieved for the established annual budgets for these programs." Based on this premise, he further asserted that "there will be no way to track or manage program spending relative to expectations. Further, program benefit projections can be over-estimated" (Alvarez, 6T 3941-42).

To the contrary, the Company provided units for strategic capital programs, including for example, the DA program (Hartwick, 4T 645) and the PTMM program (Elliott Andahazy, 4T 957). The Company also provided extensive details related to program and project units in response to discovery. Thus, there is no basis for witness Alvarez's indicated concerns, or the suggestions that he made based on those concerns (Kryscynski, 3T 413-14).

Details regarding various programs are discussed below in context, but for purposes of this general discussion about corporate governance, Company witness Elliott Andahazy explained that the Company's programs are allocated a budget (in dollars) and then based on that level of funding, the Company develops a targeted quantity of circuit miles and/or work units to be competed. The Company provided discovery responses showing budgeted versus actual capital investments and planned versus actual work units in a (1) 4.8kV Hardening Program Cost per Mile Analysis; (2) PTMM Program Investment per Mile Analysis; (3) URD Program Investment per Thousand Feet Analysis; and (4) Breaker Program Investment per Breaker Analysis (Exhibit A-51, Schedules PP2; PP4; PP5 and PP6; and PP7 and PP8, respectively). Company witness Elliott Andahazy's direct testimony also included units of work for Infrastructure Resilience and Hardening program as listed in her rebuttal testimony (Elliott Andahazy, 4T 1027-28).

vi. 2022 Actual Expenditures versus U-21297 Forecast

The projected test year is a projection of the expenditures that the Company expects and intends to make given the information known at the time of the rate case filing. There is no guarantee of recovery, but it is well-established that the Company should recover the costs of prudently incurred capital expenditures for assets that it deploys to benefit customers. Under general ratemaking principles, the Company is entitled to the return "of" and "on" its investments in providing utility service.[45] There is no basis to use hindsight to reconcile the difference between projected expenditures from a prior rate case against actual expenditures that are incurred. The Company must have flexibility to adjust to unexpected events, such as severe storms or unexpected changes in project schedules due to permitting or supply chain issues and deploy capital and resources in a way that best serves customers. [46]

Overall, the Company invested $56.6 million more in 2022 than was forecasted in Case No. U-21297 (approximately 4%).[47] The difference was driven by lower than projected base capital of $13.2 million, and increased investments in strategic capital of $69.8 million (Kryscynski, 3T 338-41; Exhibit A-23, Schedule M1 Revised, page 1, line 25).

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[45] 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).

[46] The Commission has no common-law powers, but only possesses the limited authority that the Legislature conferred upon it. *Consumers Power Co v Public Service Comm,* 460 Mich 148, 155; 596 NW2d 126 (1999). The Commission is an "administrative body created by statute and the warrant for the exercise of all its power and authority must be found in statutory enactments." *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). The Commission's authority must be conferred by clear and unmistakable statutory language, and a doubtful power does not exist. *Mason Co Civil Research Council v Mason Co,* 343 Mich 313, 326-27; 72 NW2d 292 (1955).

[47] The Order from Case No. U-21297 included $1,434.3 million of distribution plant expenditures in rate base, which was $61.8 million less than the actual amount that was reasonably and prudently incurred in 2022 (Kryscynski, 3T 341; Exhibit A-12, Schedule B5, line 7).

Mr. Kryscynski also provided and explained updated forecasts for 2023 (3T 341-42; Exhibit A-23, Schedule M2 Revised), and 2024 (3T 342-44; Exhibit A-23, Schedule M3 Revised), and discussed how the Company ensures that it has the capacities and resources required to execute its proposed strategic investments (3T 344-46).

vii. The Company's Projected DO Capital Expenditures

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 (2021 DGP) that provided a foundation for the DO capital expenditures in Case Nos. U-20836 and U-21297. Consistent with the Commission's guidance on the need for shorter-term investments and longer-term grid planning, on September 29, 2023, the Company filed an updated DGP in Case No. U-20147. This 2023 DGP (Exhibit A-23, Schedule M8) built on the 2021 DGP, and included an update to DTE Electric's distribution investment strategy considering factors including continued frequency and intensity of storms, and aging grid assets (Kryscynski, 3T 322-23). Mr. Kryscynski explained the Company's planning and its relationship to the distribution investments in this case:

> The 2023 DGP includes an increased focus on investments that will be able to quickly deliver for customers a safer, more reliable, and more storm resilient grid over the next 5 years. In addition, the updated DGP maintains its focus on the Company's 10 to 15-year vision for the grid that includes capacity needed for electrification, and advances in technology to support both reliability and incorporation of Distributed Generation(DG)/Distributed Storage (DS). The DGP supports the development of the investments that are the basis of this case. Furthermore, the direct alignment between the DGP and the investments proposed for rate base treatment illustrate the Company's long-term plans and larger strategy for improving the strength of the distribution system.

* * *

> The Company's investments as reflected in this case, and in previous cases, are based on long-term distribution planning processes that identify customer and grid needs and develop and prioritize projects that provide both benefits to customers in terms of improved safety and reliability in the near term (primarily achieved through Pole Top Maintenance and Modernization, Automation, and 4.8kV Hardening), and provide the foundation for long-term changes, including increased electrification and Distributed Energy Resource (DER) adoption, [Kryscynski, 3T 323.]

Staff recommended that the Commission "order the Company improve upon aligning spending plans between DGP and rate case filings and instruct the Company to communicate its decisions to increase or decrease spending in categories after a DGP is filed" (Becker, 6T 5041).

The Company generally supports Staff's recommendation to improve the alignment of investment plans between DGP and rate case filings. The Company's goal is to improve transparency into distribution system investment plans and related projections for its regulators, customers, and other stakeholders. There is, however, a basis for the discrepancy in investment levels, and the Company provided a summary of explanations for the most significant changes in investment levels between the 2023 DGP and this case ($107 million variance in Emergent Replacements for 2025; $100 million variance in Tree Trimming; and $71 million variance in Infrastructure Resilience & Hardening (3T 442)). The Company will work toward minimizing changes to planned investments between the rate case and DGP filings, and when strategic changes are necessary after the DGP filing, the Company will work with Staff to coordinate these changes with increased transparency (Kryscynski, 3T 441-43).

Staff also noted that it "proposed a distribution plan annual update approach in its comments to the Company's 2023 DGP that could serve as a platform to communicate changes in project spend" (Becker, 6T 5041). The Company is willing to coordinate with Staff and develop a process, structure, and requirements of proposed annual updates on changes to near-term investment plans described in the DGP (Kryscynski, 3T 443).

Company witness Kryscynski explained that the Company's DO team developed the Global Prioritization Model (GPM) to prioritize investments by ranking projects and programs based on the benefits the project or program delivers for a given level of investment. The ranking is done by evaluating a project or program across ten impact dimensions (listed and summarized in Table 7 at Kryscynski, 3T 351) that represent project benefits, and developing a total project score based on the weighting of each impact dimension. The benefits of strategic investments relate to five planning objectives: (1) Safe, (2) Reliable and Resilient, (3) Affordable, (4) Clean, and (5) Customer Accessibility and Community Focus (listed in Table 6 at Kryscynski, 3T 349), which align with the Commission's overarching objectives for the electrical distribution system of safety, reliability and resilience, cost effectiveness and affordability, and accessibility (October 11, 2017 Order in Case No. U-18014, pp 10-12; August 20, 2020 Order in Case No. U-20147, pp 36-38). The GPM results serve as the initial basis for the Company's investment prioritization and highlight the projects that have the highest relative benefit for improving the grid and the overall customer experience, and/or are most urgent (Kryscynski, 3T 346, 349-51, 355, 420-21).

The GPM was updated in 2023 to capture customer benefits that were not previously accounted for, and to include benefits from across the Company's planning objectives, as indicated above. Improvements include three new dimensions to capture additional project benefits and to align to two additional planning objectives (Clean, and Customer Accessibility and Community Focus). The "Investment in EJ communities" dimension was added based on the Commission's guidance to further incorporate equity and environmental justice considerations (November 18, 2022 Order in Case No. U-20836, pp 458-59).[48] The weightings of each dimension have also been updated (Kryscynski, 3T 348-52).

[48] Mr. Kryscynski also provided an extensive discussion on environmental justice (3T 369-93, 448-57). See also section XI. B.

In response to the Commission's guidance in the Company's last rate case concerning the DGP, GPM, and benefit-cost analysis (BCA) (December 1, 2023 Order in Case No. U-21297), the Company's distribution investments in this case are further supported by (1) the level of detail on project purpose, scope and benefits in the capital summaries (Exhibit A-23, Schedules M5, M6, and M7; (2) a new BCA methodology for PTMM and Undergrounding, with BCA spreadsheets and calculations provided in this case; and (3) a more comprehensive, circuit-level, reliability model to help tie potential investments in six key investment areas (Tree Trimming, 4.8kV Hardening, PTMM, Customer Excellence, Distribution Automation, and 4.8kV Conversion) to future reliability improvements. The Company also submitted a working version of the GPM and the Reliability Model as a workpaper in its initial filing and as an Exhibit in rebuttal (Exhibit A-43, Schedules HH4 and HH5; Exhibits MEC-71 and MEC-72) to allow for a detailed review of the prioritization process. The Company intends to continue enhancing its investment analysis, but notes that not every grid/reliability investment can be effectively translated into a monetized valuation (Kryscynski, 3T 415-16, 475. See also 3T 532-33, 595-96).

The GPM does not determine if benefits exceed costs because doing so would require all benefits to be translated into a monetary value. Only two of the benefits that the DGP captures (O&M Avoidance and Capital Avoidance) are measured in monetary terms. All other benefits are quantified in non-monetary terms because there is no standard or generally-accepted method available to convert the benefits into a monetary value. The GPM does utilize benefit-cost ratios in most dimensions, however, to provide a result where projects that deliver the most benefits per dollar invested receive the highest score (Kryscynski, 3T 347-48). [49]

[49] Benefits are weighted against costs in eight of the ten dimensions, but not in the "Regulatory Compliance" and "Investment in EJ communities" dimensions (Kryscynski, 3T 347).

More specifically, strategic investments are assessed, scored, and then ranked in a quantitative manner based on how they support/improve each impact dimension, as reflected in Table 8 at Kryscynski, 3T 353 set forth below.

Program	Reduce Electrical Hazards	Overload Relief	SAIDI	SAIFI	Regulatory Compliance	Major Event Risk	Capacity Relief	Investment in EJ Communities	O&M Avoidance	Capital Avoidance
Substation Risk						X		*		
4.8kV Hardening	X		X	X				X	X	X
PTMM	X		X	X	X			P	X	X
Cable Replacement						X		P		X
Frequent Outage			X	X	X			P		
Breaker Replacement			X	X		X		P	X	X
URD Replacement			X	X				P		X
Subtransmission Redesign		X					X	*		
CODI	X	X	X	X		X		*	X	X
4.8kV Conversion	X	X	X	X		X		*	X	X
System Loading		X	X	X		X	X	*	X	X
Automation	X		X	X				P		

Investment in EJ Community Key: * = Dependent on location of project, X = Yes, addresses EJ communities, P = program where some areas of the program will occur in EJ communities

(Kryscynski, 3T 353)

Detailed analyses based on historical data, engineering assessments, and field feedback was used to quantify each investment's benefits within each impact dimension using applicable measurements (for example, reliability benefits are captured in reduced minutes of customer interruption). The quantified benefits were then compared to the investment's costs to derive benefit-cost ratios that are used to determine the relative difference between projects. Impact dimensions are also weighted relative to each other, as reflected in Table 7 at Kryscynski, 3T 351,

with dimensions aligning with core safety and reliability improvements receiving the highest weight.

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	• Reduction in wire down events • Reduction in secondary network cable manhole events	3
Overload Relief	• Elimination of overloaded equipment	
SAIDI	• Reduction in duration of outage events	
SAIFI	• Reduction in frequency of outage events	
Regulatory Compliance	• MPSC staff's recommendation (March 30, 2010, report) on utilities' pole inspection program • Docket U-12270 – Service restoration under normal conditions within 8 hours • Docket U-12270 – Service restoration under catastrophic conditions within 60 hours • Docket U-12270 – Service restoration under all conditions within 36 hours • Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period	2
Major Event Risk	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	
Capacity Relief	• Elimination of system capacity constraints	
Investment in EJ Communities	• Percent of customers impacted by investment in EJ communities	
O&M Avoidance	• Trouble event reduction and truck roll reduction • Preventive maintenance investment reduction	1
Capital Avoidance	• Trouble event reduction and truck roll reduction • Reduction in capital replacement either during equipment failures or avoided planned capital work	

(Kryscynski, 3T 351)

Once a program's index scores have been calculated across all impact dimensions and adjusted by weighting, the index scores are then added to determine the program's overall score. The higher the score, the better the GPM ranking (Kryscynski, 3T 353-55).[50]

[50] The benefit-cost scores of programs and projects and their prioritization ranking provide the foundation for the Company's strategic investment decisions, but project selection and timing is also affected by other factors including workforce needs, system operational constraints and stability, regulatory requirements or guidance, and safety issues (Kryscynski, 3T 358-60).

Thus, the GPM is a reasonable and prudent way for the Company to compare hundreds of vastly different projects and programs, and to prioritize investments that are most beneficial to customers. Table 9 at Kryscynski, 65, shows the top 50 Strategic Capital investments and Exhibit A-23, Schedule M14 provides GPM Project and Program Rankings (Kryscynski, 3T 355-57).[51]

Rank	Capital Program/Project
1	ADMS: DMS/OMS
2	Pole and Pole Top Maintenance and Modernization (PTMM)
3	Frequent Outage Program (CEMI)
4	Subtransmission Redesign & Rebuild: Tie 1568
5	40 kV: Automatic Pole Top Switch
6	4.8 kV CC: Hawthorne Relief and Circuit Conversion
7	4.8 kV Hardening
8	CODI: Charlotte Network Upgrade
9	Distribution Automation
10	Subtransmission Redesign & Rebuild: Trunk 2237-ST
11	CODI: Garfield Network Upgrade
12	Subtransmission Redesign & Rebuild: Trunk 7105
13	Substation Risk: Savage
14	Subtransmission Redesign & Rebuild: Trunk 7106
15	4.8 kV CC: ISO Conversion Program
16	4.8 kV CC: Zenon Circuit Conversion Phase 2
17	Subtransmission Redesign & Rebuild: Trunk 2419
18	CODI: Howard Conversion
19	4.8 kV CC: McKinstry Sub Decommission
20	Substation Risk: Port Huron
21	8.3 kV CC: Pontiac Overhead/Underground Conversion
22	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion
23	Subtransmission Redesign & Rebuild: Trunk 2255
24	4.8kV CC: Barber Substation and Circuit Conversion
25	Subtransmission Redesign & Rebuild - Trunk 2448

Rank	Capital Program/Project
26	CODI: Targeted Network Secondary Cable Replacement
27	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)
28	Substation Risk: Chestnut
29	Cable Replacement Program
30	Subtransmission Redesign & Rebuild: Trunk
31	CODI: Islandview Substation
32	Subtransmission Redesign & Rebuild: Tie 3416 Reconductoring
33	Subtransmission Redesign & Rebuild: Bernard
34	CODI: Kent/Gibson Conversion
35	Subtransmission Redesign & Rebuild: Trunk 7386
36	URD Replacement Program
37	Subtransmission Redesign & Rebuild: Trunk 7333
38	CODI: Alfred Substation Expansion
39	Subtransmission Redesign & Rebuild: Trunk 4217
40	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
41	Subtransmission Redesign & Rebuild: Trunk
42	Subtransmission Redesign & Rebuild: Hurst
43	4.8 kV CC: Cortland / Oakman / Linwood Consolidation
44	Subtransmission Redesign & Rebuild: Tie 6907
45	Subtransmission Redesign & Rebuild: Cortland Station Expansion
46	Breaker Replacement Program
47	Substation Risk: McGraw
48	4.8 kV CC: Belleville Substation and Circuit Conversion
49	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
50	Subtransmission Redesign & Rebuild: Waterman

[51] Stand alone tree trimming is also a high-priority strategic program, but it is not in the table. (Kryscynski, 3T 356). See section VII. C. 5 (Distribution O&M) for a further discussion regarding tree trimming.

Improving reliability is a key focus for strategic investments. Based on the distribution investments proposed, the Company's reliability model projects that customers will experience an all-weather System Average Interruption Duration Index (SAIDI) of 504 minutes in 2024 and 482[52] minutes in 2025, versus a historical baseline of 563 minutes, assuming normal weather. Similarly, all-weather System Average Interruption Frequency Index (SAIFI) will improve to 1.31[53] in 2025 from the historical baseline of 1.37 (Kryscynski, 3T 361-62).

AG-MN witness Alvarez asserted a number of concerns about the Company's GPM. In addition to the discussion above, none of the concerns have merit as outlined below.

Witness Alvarez first suggested that the GPM does not answer certain "important questions" (6T 3959). The Company disagrees because the questions are unsupported by authority, and in some cases plainly inapplicable. For example, asking "what is the optimum geographic extent of deployment" would not be reasonable or prudent for the PTMM program, because best utility practice is to inspect all poles. The Company uses an appropriate method for evaluating strategic distribution investments, as outlined above and further detailed on the record (Kryscynski, 3T 349, 419-21).

Witness Alvarez asserted that "DTE's GPM model purports to rank capital projects and programs based on their ability to reduce risk, from highest to lowest" (6T 3959). More accurately, the GPM's impact dimensions concern benefits to customers or the grid. Some dimensions (e.g., "major event risk") measure risk, but projects also produce other benefits beyond risk reduction, such as improved reliability, additional capacity, investment in environmental justice (EJ) communities, and reduction of reactive costs (Kryscynski, 3T 422).

[52] The correct SAIDI reduction for 2025 is 482, as reflected in the company's reliability model, Schedule A-43 Exhibit HH5 and not the erroneous 487 identified at 3T 594..

[53] The correct SAIFI improves to 1.31, as reflected in the company's reliability model, Schedule A-43 Exhibit HH5 and not the erroneous 1.33 identified at 3T 361.

Witness Alvarez asserted that "[s]ome impact dimensions seem to overlap, and perhaps double-count a particular type of risk. For example, two dimensions are 'overload relief' and 'capacity relief'; three others are 'major event risk', 'SAIDI', and 'SAIFI'" (6T 3959). To the contrary, "overload" and "capacity" metrics concern different things, as explained in the 2023 DGP, Section 12.1. Similarly, "major event risk", "SAIDI", and "SAIFI" dimensions all serve different purposes, as Company witness Kryscynski explained (3T 422-23).

Witness Alvarez asserted that "most of these inputs are not data-driven (i.e., based on historical experience, research or pilot results), but based on subjective GPM assessments . . . [and] the subjective inputs outweigh the data-driven inputs" (6T 3960). That is incorrect. The GPM's inputs are (1) objective (based on measurement or observation, such as SAIDI, SAIFI, wire downs, loading data, equipment ratings, event volume, and historical costs per event), and (2) based on subject matter expertise (scored based on the assessment of people with specific expertise in the field, such as asset health assessments based on criteria concerning the likelihood and severity of equipment failure). Although the latter method is subjective, it is still quantitatively based (for example, on criteria such as the availability of spare parts in the event certain equipment fails). For all 138 projects scored in the GPM, five dimensions (Reduce Electrical Hazards, SAIDI, SAIFI, O&M Avoidance, and Capital Avoidance) are calculated entirely on objective information and contribute 45% of the overall scoring. There is also 18% for Investment in EJ Communities (using the MiEJ Screen score for the area developed by EGLE), so total scoring in the GPM is 63% objective. The dimensions including subject matter expertise also are also based on objective inputs,

as indicated above. Therefore, witness Alvarez's claims that the GPM is mostly subjective and "not data-driven" are incorrect (Kryscynski, 3T 424-26).[54]

Based on his incorrect view of the GPM, witness Alvarez further asserted that "[a] model user can get the GPM outputs he or she desires for a particular project or program simply by manipulating subjectively-assessed model inputs for the project or program" (6T 3960). There are multiple reasons why it's clear that the GPM results are not manipulated as Witness Alvarez incorrectly claims: (1) most of the inputs are based on objective measured data, as discussed above, (2) the methods used to calculate scores based on the inputs have been consistent over time and are applied uniformly to the projects and programs being evaluated, and (3) the Company requested feedback from stakeholders during technical conferences and DGP filings on suggested changes to weightings and assumptions. The entire model has been provided in this case (Exhibit A-43, Schedule HH4) so that all assumptions and weighting can be examined (Kryscynski, 3T 430).

Witness Alvarez indicated a concern that the GPM evaluates both projects and programs (6T 3961). The Company acknowledges that it is challenging to compare projects and programs, but that is one of the foundational reasons the GPM was developed (Krysinski, 3T 429).

Witness Alvarez asserted that a "big" concern is that "DTE does not use the GPM model to score its Enhanced Tree Trimming Program or the associated Surge spending" (6T 3962). Tree trimming is a required, fundamental, baseline activity. It is also an O&M expense (or deferred as a regulatory asset), so including it in the GPM would not aid in prioritizing capital projects

[54] The Company further notes that witness Alvarez's suggested alternative (RIDM approach) for California utility filings evaluates (1) safety, using the Department of Transportation's value of statistical life, and (2) reliability, using the LBNL ICE calculator – both of which were developed based on subject matter expert analysis (Kryscynski, 3T 427).

(Kryscynski, 3T 428). Moreover, the tree trim surge has been supported by a separate model – the Company's Surge Model (Exhibit A-22) which demonstrates the positive NPV for customers.

Finally, witness Alvarez indicated a concern that the GPM does not have a "baseline," and went on to suggest two flawed methodologies, the first of which is to factor a percent reduction from the baseline into GPM scoring (6T 3960). The Company disagrees because the GPM does, in most cases, include both the baseline and improvement (for example, the baseline for SAIDI is Customer Minutes Interrupted (CMI) Before). More importantly, the key measurement of risk reduction is "CMI Avoided per $M invested." For a finite budget, the projects that will provide the most overall benefit are those with the highest CMI per million dollars invested, not those with the highest percent change in CMI compared to a baseline as witness Alvarez suggested (Kryscynski, 3T 431-32).

Witness Alvarez also recommended that the Company instead "determine the appropriate capital budgets and deployment speeds for various capital programs" by using "a systematic approach called risk-informed decision-making, or 'RIDM' (also known as risk-informed decision support, or 'RIDS')." (Alvarez, 6T 3963).

The Company disagrees that it would be appropriate to use this framework, which is what California uses for investments to address large-scale public safety risks such as wildfires and earthquakes. Witness Alvarez also neglected to mention the framework's long development history. In general summary: (1) the framework was developed over the course of a decade and evolved through many iterations, (2) the development was led by the California PUC and based on joint working sessions among the utilities, (3) the framework is applied to all investor-owned utilities (IOUs) in the state; and (4) the framework is very complex, and has both quantitative and qualitative metrics. It would not be reasonable to adopt California's framework regarding investments concerning that state's particular catastrophic safety risks in a short period of time, and without due

diligence which (assuming the framework could be adopted at all) would be necessary to tailor the framework to Michigan. Instead, as indicated above and further discussed below, the Company's investments are supported by a holistic view of benefits and costs, and the GPM is a sound method for evaluating the relative benefits of different investments based on safety, reliability, capacity and equity (Kryscynski, 3T 417-18).

Witness Alvarez also provided an example of how his proposed alternative methodology would select investments, and concluded that the optimal solution "would retain [invest in] projects 1, 2, and 3 in the budget" (6T 3964). That is mathematically incorrect, so the alternative method failed to achieve its intended result. The Company conducted its own analysis using Mr. Alvarez's numbers to optimize the hypothetical portfolio. When ranked on benefit (Risk Reduction) vs cost (PVRR), the optimal portfolio would select Projects 1, 5, 3 and 2, in that order, and project 5 should certainly be prioritized before projects 2 and 3, as shown in Table 5 (Kryscynski, 3T 432-33).

Project	PVRR ($M)	Risk Reduction	Risk Reduction per $M PVRR
1	$ 24	180	7.6
2	$ 49	147	3.0
3	$ 39	125	3.2
4	$ 88	79	0.9
5	**$ 15**	**74**	**4.9**
6	$ 40	68	1.7
7	$ 34	53	1.6
8	$ 19	41	2.1

(Kryscynski, 3T 433)

Witness Alvarez asserted that "DTE uses the Reliability Model's improvement projections to justify the size of its strategic capital budgets. By implication, the Model's reliability improvement projects [sic] are also intended to justify most of the Company's request to extend and expand rider IRM" (6T 3966).

This is not accurate. The Reliability Model is just one component of support for the six reliability improvement programs/projects (Tree Trimming, Distribution Automation, PTMM, Customer Excellence, 4.8kV Hardening, and 4.8kV Conversion). Additional support is provided by capital summaries, testimony, and the GPM. (3T 434).

Witness Alvarez made four assertions about how reliability modeling should be performed. First, Witness Alvarez assumed that the Company used a "difference of differences" approach, and discussed drawbacks of using this approach for modeling (6T 3968-69). The Reliability Model instead uses a different type of analysis that was provided in discovery (Exhibit A-43, Schedule HH6). For example, there is a comparison of "before" and "after" on the same set of circuits for 4.8kV Hardening, so there is no control group as witness Alvarez assumed (Kryscynski, 3T 435-37).

Second, Witness Alvarez suggested that a model should separate the impacts of tree trimming and strategic capital programs (6T 3967). The Reliability Model did so in two ways: (1) the benefits are calculated separately for tree-related and non-tree related events, and (2) the circuit-level baseline is calculated separately for tree and non-tree related outages (Kryscynski, 3T 377, 437-38, 568; Exhibit A-43, Schedule HH6).

Third, Witness Alvarez suggested that a model should use multiple years of baseline reliability to account for weather variation (6T 3969-70). The Reliability Model does so. For example, with regard to 4.8kV Hardening discussed above, the reliability benefit assumptions use multiple years of weather data in the baseline by using circuits that have had treatment across multiple years (Kryscynski, 3T 437-38).

Last, Witness Alvarez asserted that a model should use accurate units to project reliability improvements, and presented a table to suggest that reductions in unit costs indicate that the units used in the Reliability Model cannot be achieved (6T 3970-71). There is no basis for the indicated

concern. The Reliability Model uses accurate counts of units aligned to the Company's investment plan. Witness Alvarez's unit cost analysis also has three flaws that prevent any conclusions being drawn from it: (1) costs are off by a factor of ten, so the whole table is off by that magnitude; (2) all costs are not included in calculations for future years; and (3) the analysis does not account for other programmatic factors (e.g., the shifting work mix for multi-year programs). (Kryscynski, 3T 438-40).

AG-MN witness Stephens began his discussion by asserting that "all of the spending categories I have examined constitute distribution capital spending that is discretionary. I define discretionary spending as 'If the capital is not spent, can customers still have safe and reliable service?' If the answer is no, then the spending is non-discretionary (mandatory). If the answer is yes, then the spending is discretionary and a risk-informed benefit-cost analysis should be performed to quantify whether the dollar value of the risk reduction to customers exceeds project costs to customers" (Stephens, 3989-90).

Witness Stephens' definition of "discretionary" investments is flawed because it oversimplifies the planning and scope of investments needed to have a safe, reliable, and accessible grid. He appears to focus on only addressing immediate conditions, instead of planning ahead to address future safety and reliability risks (by analogy, replacing a worn tire is "discretionary" until it skids or blows out). Witness Stephens also neglects that in-service failures are typically more expensive than carefully-planned investments (Kryscynski, 3T 402).

AG-MN witness Alvarez similarly asserted that "almost all of the projects in these [strategic capital] programs are discretionary as to timing and extent. This means that none are required to address equipment failures or equipment damage; or connect new customers; or accommodate near-term load increases" (6T 3928). To the contrary (for example and as further discussed below), the PTMM Program is targeted at replacing failed and damaged equipment. That program, as well as

the Breaker Replacement, System Cable, and URD Programs also target replacing equipment that has either failed or is known to have high failure rates and is expected to fail again in the near future (Kryscynski, 3T 403).

AG-MN witness Alvarez suggested that the Company replaces equipment "simply because it is fully depreciated" (6T 3932). Witness Alvarez is incorrect. He apparently assumed that the Company used the term "expected useful life" as a reference to depreciation periods (Alvarez, 6T 3931), which is incorrect as the Company pointed out in response to discovery (Exhibit A-43, Schedule HH). The Company also explained in testimony that its subject matter experts use many factors to determine equipment life expectancy (including age but not depreciation status) in estimating investment needed for equipment replacements (Kryscynski, 3T 309, 405-406).

AG-MN witness Stephens asserted that "storm response and vegetation management – not equipment condition – have driven the Company's historically poor (relative to peers) reliability performance" (6T 3990). AG-MN witness Alvarez similarly asserted that "[g]iven that vegetation contact is the root cause of at least 50% of the interruption minutes customers experience, spending should be focused on root causes . . . tree trimming, and not capital spending, is the most cost-effective way to improve reliability" (6T 3933).

The Company agrees that vegetation is a significant cause of outages, which is why the Company began the Tree Trim Surge program (as discussed in section VII. C. 5); however, focusing solely on vegetation would not address the complex set of factors that influence distribution reliability. The full analysis of grid reliability needs to address both the initiating event that caused the outage (trees/wind) and the underlying equipment that was not resilient to the trees/wind (Kryscynski, 3T 406-407).

Witness Stephens' characterization of the Company's "storm response" as a key driver impacting reliability performance also neglects that the real issue impacting storm response has

been, and continues to be, the volume of events that occur during a narrow window of time during large weather events. Even with additional support from foreign crews, there are supply vs. demand challenges for restoration. Also, the event volume is driven, in part, by equipment that is no longer capable of standing up to increasingly harsh weather conditions (Kryscynski, 3T 407-408).

AG-MN witness Alvarez also attempted to support his position by asserting that "[r]esearch completed by Lawrence Berkeley National Laboratory on behalf of the U.S. Department of Energy found no correlation between investor-owned utility distribution capital spending increases and reliability improvement the following year" (6T 3930). Witness Alvarez's reliance on the Lawrence Berkeley National Laboratory (LBNL) study (Exhibit A-43, Schedule HH2) is misplaced because that study did not analyze capital investment, but instead discussed spending in terms of "maintenance" (O&M). A subsequent journal article by the same authors (Exhibit A-43, Schedule HH3) similarly defined spending as "T&D O&M expenditures." (Kryscynski, 3T 409).

AG-MN witness Stephens apparently reviewed outage crew field notes on a small sample of outage events, and came to the conclusion that "the percentage of SAIDI caused by cause "equipment" is just 11.9%" (Stephens, 6T 3991). Witness Stephen's analysis was unclear and the Company was unable to verify what witness Stephens did. The Company also performed further analysis reflecting that equipment is a leading cause of outages over the past five years, particularly when MEDs are removed from consideration (Kryscynski, 3T 410-11).

AG-MN witness Alvarez recommended that the Commission "[r]equire DTE to slow the rate of capital spending and assess the benefits of its vegetation management program relative to strategic capital spending aimed at improving reliability" (6T 3922). The Company disagrees. In addition to the discussion above:

1. Customers want to see significant reliability improvements even in the face of storms.

2. With 90% of the system on cycle for the end of 2024, the Company's reliability model indicates that the two largest opportunities to improve reliability are Circuit Automation and replacing degraded equipment (PTMM, Hardening, Conversion), which will account for almost 80% of the projected all-weather SAIDI improvements by 2029. Delaying this work will hamper the Company's ability to improve reliability in the near term.

3. Although the Tree Trim program is highly effective, the Company's recent reliability performance shows that more capital infrastructure investment is needed (Kryscynski, 3T 412).

Company witness Kryscynski also touched on a number of additional points regarding the Reliability Model, BCA, and other matters in response to CEO witness Volkmann's recommendations (Kryscynski, 3T 445-49).

viii. Specific Strategic Capital Investment Programs

DTE Electric's planned Strategic Capital investments are focused 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 an increasing frequency and severity of high winds and storms, address frequent outage circuits, and replace damaged and/or defective infrastructure. The Company projects capital costs associated with these projects of $671.5 million for the 24 months ending December 31, 2024, and $364.7 million for the projected test year (Elliott Andahazy, 4T 911; Exhibit A-12, Schedule B5.4, page 13, line 37, columns (f) and (g); Exhibit A-

23, Schedule M5). The Company plans to invest in 16 different programs in this category (listed at Elliott Andahazy, 4T 912, and discussed at 4T 912-1020). Seven warrant particular discussion: (1) 4.8 kV Hardening, (2) Pole and Pole Top Maintenance and Modernization (PTMM), (3) Substation Risk, (4) Frequent Outage Programs (CEMI), (5) Cable Replacement, (6) Underground Residential Distribution (URD) Replacement, and (7) Breaker Replacement, as discussed below.

1. 4.8kV Hardening

The 4.8kV Hardening Program was developed as a cost-effective way of providing improvements in safety and reliability in areas in and around Detroit that have abandoned Detroit Public Lighting Department (DPLD) arc wire. The 4.8kV Hardening Program is a near-term program, which provides for the faster removal of arc wire, along with improved reliability and safety, ahead of the longer-term circuit conversions that are planned to ultimately replace the 4.8kV infrastructure. Program activities include removing DPLD arc wire (consistent with the Commission's Order in Case No. U-18484) and DPLD distribution wire from DTE Electric-owned equipment, replacing or reinforcing poles as necessary, replacing wooden cross-arms with fiberglass cross-arms, removing service lines to abandoned properties, removing primary conductor in sparsely-populated areas (primary deconductoring), and trimming trees to support construction activities (Elliott Andahazy, 4T 913-14, 930-31).

The 4.8kV Hardening Program originated in Case No. U-20162, where the Commission agreed with the ALJ, who "agreed with DTE Electric that the 4.8kV hardening proposal is economically efficient and that a more complete conversion of the system to 13.2kV would be expensive and provide limited incremental benefit" (May 2, 2019 Order in Case No. U-20162, pp 31, 33). The Commission similarly supported investments in the program in Case Nos. U-20561, U-20836, and U-21297.

The Commission directed the Company to create a comprehensive, detailed and longer-term plan that includes an equity and safety analysis (December 1, 2023 Order in Case No. U-21297, p 93). Accordingly, the Company performed an Environmental Justice (EJ)/equity analysis of the 4.8kV Hardening Program by mapping its circuits to census tracts and cross-referencing with the MiEJScreen tool. The analysis reflects that 85% of all 4.8kV Hardening Program investments from 2018-2025 impact communities that score in the top 80-100% MiEJ scores and are deemed vulnerable (Kryscynski, 3T 358; Elliott Andahazy, 4T 923).

The Commission also indicated that the work should proceed faster, stating:

> [C]ompleting this work is critical to the residents and businesses located in areas that contain abandoned arc wire and the Commission agrees with Staff that the removal of the arc wire should be going faster. While the work is expensive (in part because hardening means going back to the same pole twice), comprehensively addressing the safety and equity concerns is a priority and the Commission recognizes that conversion takes much longer than hardening. . . Finding this work to be imperative, however, the Commission approves the requested bridge period and test year funding and expects to see results in DTE Electric's next rate case, including an accelerated removal of the arc wire as discussed by the Staff. [December 1, 2023 Order in Case No. U-21297, p 93-94.]

Accordingly, the Company accelerated its plans for removing arc wire. The Company hardened approximately 373 miles in 2023, and nearly 1,500 total miles from 2018-2023, which represents approximately 70% of the total program scope. The Company removed approximately 208 miles of arc wire in 2023, and approximately 640 miles total from 2018-2023. [55] The 2024 workplan includes hardening approximately 145 circuit miles, and removing 95 miles of arc wire. The 2025 workplan includes hardening approximately 310 circuit miles, and removing 189 miles of arc wire.

[55] There are fewer miles of arc wire removed than miles hardened because the DPLD system does not perfectly overlap the Company's distribution system. There is a fixed cost for planning work and mobilizing and demobilizing crews, so the Company hardens the entire circuit so that all customers in the area benefit from improved safety and reliability (Elliott Andahazy, 4T 924-25).

The 2026 workplan includes hardening approximately 116 circuit miles, and removing 89 miles of arc wire (Elliott Andahazy, 4T 923-25).

Customers have benefitted because the program has proven very effective in improving the safety, reliability, and resiliency of circuits. Circuits that were hardened experienced (1) a 38% reduction in All-Weather SAIFI vs. an increase of 23% in the control group (61% net improvement), (2) a 65% reduction in SAIDI ex-MEDs vs. a 3% reduction in the control group (62% net improvement), and (3) a 25% reduction in wire downs vs. an increase of 22% in the control group (47% net improvement). (Elliott Andahazy, 4T 927-30,1029-31).

AG-MN witness Stephens suggested that the Company overstated wire down benefits because "while the removal of DPLD wire . . . eliminates the risk that an energized *DPLD* wire will fall to the ground, it does NOT eliminate the risk that an energized *DTE* conductor will fall to the ground . . . ." (6T 3993-94. Emphasis in original). The first part of the statement is accurate, but the Company has not claimed that the program completely eliminates the risk of wire downs. Instead, as indicated above, analysis shows a 25% reduction in wire down events on hardened circuits when comparing the three-year average before hardening to the one-year after (Elliott Andahazy, 4T 930, 1029).

AG-MN witness Stephens further stated that the "Company appropriately employs a 'difference of differences' approach to quantifying reliability improvements from various capital programs using 'test' and 'control' groups of circuits, but the Company's control group definition dramatically exaggerates reliability improvements from capital programs by eliminating circuits that have tree trimming" (6T 3993).

To the contrary, the intent of the comparison was to show the benefits of 4.8kV Hardening versus a "do-noting scenario," which was the same methodology used in Case Nos. U-20836 and U-21297. The data (summarized above) shows that – even without considering the control group –

there are significant All-Weather SAIFI, SAIDI excluding MEDs, and wire down event improvements from the 4.8kV Hardening program, with compelling benefits to customers (Elliott Andahazy, 4T 1027-30, 1030-31). The Company also did not use a "difference of differences" approach, as discussed above (Kryscynski, 3T 435).

AG-MN witness Stephens further suggested that the 4.8kV Hardening program's scope is redundant because "replacing crossarms when defects are identified is part of the pole top maintenance program in any event," and "DTE is required to complete the tree trimming in any event, meaning that the reliability benefits from tree trimming should not be credited to the 4.8kV Hardening program" (6T 3995-96).

The programs are not redundant. Circuits in the 4.8kV Hardening program are currently excluded from the PTMM Program and will have PTMM work in some future PTMM cycle. It is not redundant to trim circuits being hardened, and this is required so crews have safe and efficient access to equipment. The 4.8kV Hardening Program coordinates its work with the Tree Trimming program, and those programs are complementary. Tree trimming certainly provides significant benefits (as discussed in section VII. C. 5) but trimming trees alone does not improve the condition of poles and pole-top equipment. Replacing poles and pole-top equipment with newer and stronger designs and materials improves the grid's ability to avoid wire downs and outages from inclement weather and tree impacts (Elliott Andahazy, 4T 1032-33).

The Company presented an analysis (Exhibit A-51, Schedule PP9), which demonstrates that the 4.8kV Hardening Program provides significant safety and reliability benefits three years after work is performed. This analysis includes 2021 and 2023, which were historic storm years when overall system reliability experienced the greatest impacts. Thus, the 4.8kV Hardening Program has demonstratively provided significant and persistent safety and reliability benefits to some of the Company's most vulnerable customers in and around Detroit (Elliott Andahazy, 4T 1033-35).

AG-MN witness Stephens also asserted that "most of the work completed under the 4.8kV Hardening program (other than full tree trimming, which must be completed irrespective of hardening) will be rendered redundant when a 4.8kV circuit that has been hardened is converted to a 13.2kV circuit. DTE cannot justify the installation of fiberglass crossarms with a service life likely in excess of 50 years on a circuit DTE aims to convert to 13.2kV in the next 15 years or so" (6T 3997).

To the contrary, the 4.8kV Hardening Program coordinates with the 4.8kV Conversion Program to ensure that circuits selected for near-term conversion (five years) are not hardened, and that the circuits that were selected for 4.8 kV hardening are not expected to see significant load growth so they are unlikely to be prioritized for conversion. The Company's 15-year conversion goal is also a directional target, recognizing that the grid will ultimately be rebuilt at a pace required to support customer needs and affordability. The 4.8kV Hardening Program also uses pole-top equipment that is equivalent to the equipment used for 13.2kV circuit configurations, and which therefore might be retained when the hardened circuits are converted to 13.2kV. Meanwhile it is reasonable and prudent to perform work now to improve safety and reliability for some of the Company's most vulnerable customers in and around Detroit (Elliott Andahazy, 4T 1038-39. See also, Deol, 5T 1225-26).

AG-MN witness Stephens asserted that "[r]emoving the DPLD wire alone will provide almost all of the safety benefits of the 4.8kV Hardening Program at greatly reduced cost, and with greater deployment speed [citing DTE Technical Conference presentation March 22, 2023 which is Exhibit A-23, Schedule M12]. The marginal added safety benefits of the 4.8 kV Hardening program over the option to simply remove the DPLD wire are due to two extra steps the 4.8kV Hardening program takes over the 'remove DPLD Only" option to reduce the risk that DTE conductor will fall to the ground" (6T 3994).

To the contrary, the cited presentation (Exhibit A-23, Schedule M12, p 39) reflects that DLPD arc wire removal would provide approximately 50% of the benefit for approximately 55% of the investment required for the 4.8kV Hardening Program, so that alternative did not strike the best benefit-cost balance, as indicated above. The 4.8kV Hardening Program also does not simply involve "two extra steps" as compared to just DLPD arc wire removal, but instead includes: (1) more intensive tree trimming on twice as many circuit miles; (2) pole-top inspection and replacement on twice as many circuit miles ; (3) pole inspection and replacement on twice as many circuit miles; (4) removal of abandoned service lines; and (5) primary deconductoring in abandoned areas (Elliott Andahazy, 4T 1036-37).

Based on his premise that DPLD arc wire removal alone would provide comparable safety benefits cheaper and faster (which is incorrect as discussed above), witness Stephens further speculated that the Company's selection of the 4.8kV Hardening Program "may be" due to an interest in growing its rate base (Stephens, 6T 3996). To the contrary, and in addition to the discussion above, Company witness Elliott Andahazy summarized:

> The Company selected the 4.8kV Hardening Program to maximize benefits to customers when considering the fixed costs associated with planning and managing the work as well as mobilizing and demobilizing crews. 4.8kV Hardening Program scope was designed to eliminate DPLD arc wire downs, reduce DTE Electric distribution wire downs, increase reliability for customers, remove abandoned service lines, and perform deconductoring in abandoned areas. Additional scope beyond only removing DPLD arc wire was added to take advantage of the fact that crews would already be mobilized to perform work on the circuits and because customers would receive increased benefits from the added scope. [4T 1039.]

Based on his inaccurate view of the 4.8kV Hardening Program and similarly-unfounded supposition about the Company, witness Stephens further suggested that a cost-benefit analysis is needed to determine whether the 4.8kV Hardening program provides greater safety and reliability benefits per dollar than removing DLPD arc wire alone (Stephens, 6T 3996).

The Company disagrees because the 4.8kV Hardening Program is a mature program that has been ongoing since 2018 and is scheduled to be completed in 2026. The Company provided actual performance data in Case Nos. U-20836 and U-21297, and in this Case No. U-21534, showing significant and persistent benefits to customers (Elliott Andahazy, 4T 927-30, 1033-34, 1040-41; Exhibit A-51, Schedule PP9). Moreover, suspending the program to do a CBA would cause delays and be contrary to the December 1, 2023 Order in Case No. U-21297, p. 93 ("completing this work is crucial to the residents and businesses located in areas that contain abandoned arc wire and the Commission agrees with the Staff that the removal of the arc wire should be going faster").

AG-MN witness Stephens concluded his discussion of the 4.8kV Hardening Program with a series of recommendations. He recommended that the Commission order the Company to eliminate the 4.8kV Hardening program in favor of removing DPLD wire only. He suggested reducing test year spending to match the cost of removing the same miles of DPLD wire as would have been hardened with the $80 million requested for 2024. Since DPLD wire removal is 46% less than 4.8kV Hardening per circuit mile, he proposed reducing the Company's test year capital spending to $43.2 million. Additionally, he recommended disallowing $73.333 million from the bridge period (2024) due to DTE Electric's alleged excess spending and failure to evaluate the efficacy of hardening independently of tree trimming. [Stephens, 6T 3998].

Witness Stephens' recommendations should be rejected as unfounded as well as contrary to past proceedings and the record in this case, as discussed above. Moreover, the proposed disallowance for 2024 based on Case No. U-21297 is contrary to the Commission's direction in that case that "the removal of the arc wire should be going faster" (December 1, 2023 Order in Case No. U-21297, p 93). The Company's acceleration of the 4.8kV hardening Program is consistent with the Commission's statement. Also, the 4.8kV Hardening Program will have completed its 2024

workplan by the time the Commission issues its order. Customers will receive the benefits, and it will not be possible to undo the work and associated investment. Changing the program to just DPLD Arc Wire Removal for 2025 would also result in lower safety and reliability benefits for customers, and would require the development of new work-scope packages, which would delay removing DLPD arc wire (Elliott Andahazy, 4T 1042-43).

Witness Stephens' proposed disallowances should also be rejected because 4.8kV Hardening is a mature program. The Company has repeatedly demonstrated that the program is reasonable and prudent, and received Commission support in Case Nos. U-20162, U-20521, U-20836, and U-21297. The Company also presented an analysis of alternatives in its March 22, 2023 Technical Conference, and changes could have been ordered in Case No. U-21297, but the Commission instead approved funding and indicated an expectation for accelerated arc wire removal. December 1, 2023 Order in Case No. U-21297, p 94 ("Finding this work to be imperative, however, the Commission approves the requested bridge period and test year funding and expects to see results in DTE Electric's next rate case, including an accelerated removal of the arc wire as discussed by the Staff"). (Elliott Andahazy, 4T 1043-44).

Therefore, the Commission should reject Mr. Stephens' proposals for lacking a sound evidentiary basis, as well as for being demonstrably unreasonable, unsafe, 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.

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

This program inspects all wood poles and all pole-top equipment on distribution and subtransmission overhead circuits and identifies and replaces poles and pole-top equipment that fails inspection (Elliott Andahazy, 4T 939-41). In 2019 the Company added enhanced specifications

concerning testing and inspection processes based on benchmarking and other learnings[56], and renamed the program from PTM to PTMM to reflect this inspection specification change in addition to changes made in construction and material specifications from 2012-2019. The enhanced pole specifications and inspection process align with industry best practices and reduce the risk of pole and pole top equipment failures, improve customer reliability, and reduce reactive costs. Additional program improvements were made in 2021 and 2022 (including no longer using Joint Use inspections[57] to achieve a 10- to 12-year pole inspection cycle and assembling a new team to enhance the PTMM program management), and 2023 (concerning inspection quality control, and process improvements). Customers benefit because overhead-equipment related outages account for approximately 25% of all outages customers experience during all weather conditions, and over 30% of all outages customers experience excluding Major Event days (MEDs). (Elliott Andahazy, 4T 933-38, 948-50, 1076).

The Company determines whether a pole should be reinforced or replaced based on its pole inspection process (Elliott Andahazy, 4T 941-45; Exhibit A-23, Schedule M9). The Company decides whether pole-top equipment should be replaced based on its pole-top inspection process (Elliott Andahazy, 4T 945-46; Exhibit A-23, Schedule M10).

In Case No. U-21297, the Commission approved cost recovery of $63.45 million per year, and indicated concerns about recent increases in investment levels. The Commission ordered the Company to prepare an annual pole and pole-top inspection report, which is similar to the

[56] The Company 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, 4T 930-32, 945, 1044-45).

[57] 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 (Elliott Andahazy, 4T 949).

Company's annual tree trimming report, and to complete a benefit-cost analysis (BCA) of the program (December 1, 2023 Order in Case No. U-21297, p 93).

The Company has provided pole inspection reports to Staff annually since 2010, in accordance with Staff's 2009 Utility Pole Inspection Program Investigation Staff Report. At the time that the Company's direct case was being prepared, the data for the additional report was being assembled (Elliott Andahazy, 4T 946-47).

The Company completed a BCA, as directed, in February 2024. The overall average benefit-cost ratio for the system was calculated as 3.8, meaning that if PTMM could be conducted on 100% of the Company's distribution grid, then the benefits realized by customers would be 3.8 times greater than the benefits if the Company instead ran all poles and pole-top equipment to failure (Elliott Andahazy, 4T 947-48).

The PTMM Program's largest cost driver is the inspection process identifying more defective pole and pole-top locations, with corresponding increases in remediation work and costs. In 2022 and 2023, the program increased defective pole replacements by over 2,900 poles per year, which was driven by (1) higher pole reject rates, (2) higher levels of PTMM inspections (not including Joint Use), and (3) a focus on backlog reduction. During that same timeframe, the program increased defective pole-top equipment replacements by approximately 5,500 pole-top locations per year, which was driven by (1) higher pole-top defect rates based on updated inspection standards, (2) enhanced quality control (training, field audits, etc.), and (3) higher circuit miles being addressed (Elliott Andahazy, 4T 950).

Due to the limited $63.45 million per year of funding approved in Case No. U-21297, the Company does not plan to complete inspections in 2024 and 2025 consistent with the 10-12 year cycle discussed above. To avoid creating a backlog of work rising above approved investment levels, the Company will complete inspections consistent with the amount of funding available to

complete the associated construction activities. For this reason, the Company categorized circuits into four tiers, based on the frequency and magnitude of reliability issues that customers experience. For 2024, the Company prioritized work based on the worst reliability circuits and validated the workplan with the BCA discussed above. For 2025, the Company selected circuits based on the tree trim cycle, benefit-cost ratios calculated by the BCA, circuit reliability tiers, and operational concerns (e.g. field resources available in each region to perform the work) (Elliott, Andahazy, 4T 955-956). The benefit cost ratios for the workplans are 3.6 for 2024, and 5.0 for 2025 which validate the Company's selection criteria to maximize customer benefits (Elliott Andahazy, 4T 953-56, 958).

The 2024 workplan is consistent with the $63.45 million of funding approved in Case No. U-21297, and includes replacing poles and pole-top equipment on approximately 750 circuit miles (replacing approximately 1,700 poles, and pole-top equipment that has failed inspection at approximately 8,655 locations). The program will also inspect approximately 39,250 poles to support future workplans (Elliott Andahazy, 4T 956-57).

For 2025, the Company requests approval to invest $121 million to replace poles and pole-top equipment on approximately 1,100 circuit miles (replacing approximately 3,965 poles, and pole-top equipment that has failed inspection at approximately 13,800 locations) and inspect approximately 53,500 poles to support future workplans. The Company proposes cost recovery through the IRM after the projected test year (Elliott Andahazy, 4T 957. See also section VIII. A regarding the IRM).

AG-MN witness Stephens asserted that "DTE solicited a consultant after it decided to increase the pole construction standard, and after millions of dollars had already been spent. In my experience, the purpose of completing benefit-cost analyses on spending proposals is to make better decisions regarding those proposals *before* costs are incurred. In this case, a benefit-cost analysis

on the PTMM program was completed after the fact in an apparent attempt to retroactively justify the change in standards which DTE had already made (Stephens, 6T 4011-12. Emphasis in original).

The BCA was not performed to "retroactively justify the change in standards," but instead to demonstrate that customers benefit from the PTMM Program. As indicated above, the changes to standards were informed by benchmarking and industry research. Some of this work included the Company's participation in a three-year research program with the Electric Power Research Institute (EPRI), which culminated in a Distribution Grid Resiliency Report (Exhibit A-51, Schedule PP14). [58] The decision to perform a BCA was made in 2023 after the Company reviewed feedback that it received from Case No. U-21297 (Elliott Andahazy, 4T 936-38,1046-47).

AG-MN witness Stephens further suggested that the BCA is not well founded because the Company does not have precise data on the quantity of customer outages resulting from specific types of pole-top equipment failures (6T 4012). The suggested concern lacks merit because the BCA was performed by 1898 & Co., which has assisted nineteen other utilities with similar projects, and their analysis has been used to support multi-billion-dollar investments in nine states. They maintain a proprietary database of asset failure curves that were reviewed and approved by the Company's engineering subject matter experts, and which were applied to the Company's actual asset age profiles (Elliott Andahazy, 4T 1048, 1096, 1109; Confidential Exhibit A-51, Schedule PP10).

AG-MN witness Stephens further asserted that "the PTMM benefit cost analysis overestimates the benefits from avoided costs by assuming that every truck roll (for example, to

[58] In response to AG/MN witness Stephens' indicated concerns about the analysis supporting the Company's changed construction standards (6T 4009, 4011), Company witness Elliott Andahazy further explained that the Company's engineers performed analysis, and benchmarking and cross-functional workshops occurred over a large span of time beginning over a decade ago (4T 1045-46; Exhibit A-51, Schedule PP13).

respond to a pole top equipment failure or a related service interruption) reduces DTE's costs by $2,000. This appears to be a fully-loaded cost . . . What is needed for this estimate is the marginal cost avoided by a truck roll, which is typically gasoline (for the truck) and perhaps some overtime costs" (Stephens, 6T 4012-13).

Witness Stephens' suggestion is flawed because it ignores the opportunity costs associated with the inefficiency of dispatching field personnel to address customer outages and wire downs due to emergent pole and pole-top equipment failures, rather than more efficiently performing work on the entire circuit. Also, the Company tested the sensitivity of truck roll assumptions, and the results show that the PTMM BCA Model is not sensitive to the value placed on truck rolls (Elliott Andahazy, 4T 1049-50).

AG-MN witness Stephens further asserted that "the PTMM BCA also understates customer costs. The costs in the model represent the present value of the costs the Company must pay. It does not include the costs customers must pay on top of DTE capital costs, including DTE's interest expense, a rate of return for shareholders, property taxes DTE must pay to local governments, or state and federal income taxes on the profits DTE earns on PTMM capital spending. Between overstated benefits and understated costs, the Company's representation that the upgraded pole top construction standards, or the PTMM based on those standards, deliver benefits in excess of costs rests on a weak foundation" (Stephens, 6T 4013).

The suggestion that the PTMM BCA Model does not account for interest expense, return to shareholders, and income taxes is incorrect. The Model uses a 6.92% discount rate, which is the Company's pre-tax weighted-average cost of capital, and which incorporates the cost of debt, the cost of equity, and the respective weights of each type of capital. The stream of benefits enabled by the investment is discounted by 6.92%, and then compared to the capital investment required, which is a valid comparison (Elliott Andahazy, 4T 1051).

The further suggestion that the PTMM BCA Model rests on a "weak foundation" for property taxes neglects that all equipment replacements affect property taxes. Although there is an incremental property tax associated with performing PTMM, it only applies to the PTMM investment that is above the amount that would be incurred for emergent capital replacements (Elliott Andahazy, 4T 1051-52).

AG-MN witness Stephens suggested that the PTMM BCA Whitepaper refers to only 2,242 modeled circuits, and it is not clear where benefit-cost ratios are provided (6T 4013-14). Although the PTMM BCA whitepaper does have a reference to 2,242 modeled circuits, the Company provided the PTMM BCA Model in its entirety in discovery (Exhibit A-51, Schedule PP10). The "Summary" tab contains a total of 3,844 circuits including subtransmission circuits, with 2,360 of these having a cost-benefit ratio at or above one. The Company also informed MNSC in discovery (Exhibit A-51, Schedule PP12) that this was the field that demonstrated the cost-benefit ratio for circuits, and which was used to determine whether a circuit was suitable for the PTMM Program (Elliott Andahazy, 4T 1055).

AG-MN witness Stephens concluded with the following recommendations for further analysis and to cap test year spending:

> I recommend the Commission order DTE to present an assessment of the reliability difference between PTM circuits and PTMM circuits using historical data in a way that prevents the comingling of tree trimming benefits, and to calculate the monetary value of the reliability improvements relative to the incremental costs of the new pole top construction and inspection standards. This information is necessary for DTE to support its proposed increasing level of capital spending in the PTMM program.
>
> Regarding test year spending, DTE has not supported the request to increase spending in the PTMM beyond what was approved in U-21297, which was $63.45 million. The Commission should cap test year spending accordingly. [Stephens, 6T 4014-15.]

The Commission should reject these recommendations because, as discussed above, the Company's inspection and construction specification changes are supported by benchmarking and industry research. The Company also performed a BCA showing that the PTMM Program (with the new specifications) is cost-beneficial to customers. Thus, the program investments are well supported and should be approved, and there is no need for witness Stephens' proposed alternative analysis (Elliott Andahazy, 4T 939-40).

3. Substation Risk

These projects are designed to remediate failures at substations that have occurred or prevent catastrophic substation failures in the future. A substation typically supports several circuits, so catastrophic failure events often impact a large number of customers. They can also result in lengthy outages because an entire substation is difficult to restore, with methods often limited to Mobile Fleet Program assets such as diesel generators and portable substations or switching load to adjacent substations with available jumpering capacity. These projects are prioritized using the GPM at substations where deployment of Mobile Fleet program assets cannot restore the entire substation load (customers will be without electricity for more than 24 hours in the event of a failure). (Elliott Andahazy, 4T 959-60).

Details of the projects included in this case are in Exhibit A-23, Schedule M5. Company witness Elliott Andahazy also explained the drivers, scope, and customer benefits, and supported cost recovery for the McGraw project (4T 960-66), Flood Defense program (4T 966-68), Apache project (4T 968-70), Chestnut project (4T 970-72), Savage Stranded Load project (4T 972-73), Belleville Switchgear Decommission project (4T 973-75), Voyager project (4T 975-76), Drexel project (4T 976-77), Savage Switchgear Replacement project (4T 977-79), Seville project (4T 979-80), and Imlay project (4T 980-82).

4. Frequent Outage Programs (CEMI)

There are two primary programs under Frequent Outage (a/k/a Customers Experiencing Multiple Interruptions, or CEMI), programs: (1) Customer Excellence (CE), which provides rapid solutions to small pockets of customers experiencing poor reliability; and (2) Strategic Reliability Improvement Program (SRIP), which performs improvements to either portions of a circuit (customer pockets), or entire circuits as appropriate (Elliott Andahazy, 4T 982-83).

Following 2021's historic storm season that impacted a significant number of customers, the Company implemented a new Pre-Storm Season Strengthening (PS3) process to identify circuits expected to have the worst reliability performance and allocate those circuits to various programs to ensure they receive improvements before the next summer storm season. For 2023, work was performed on 255 circuits within the Frequent Outage (CEMI) Programs. The Company plans to perform work on 166 circuits in 2024, and 215 circuits in 2025 (Elliott Andahazy, 4T 983-84).

These investments are reasonable and prudent to improve grid resiliency, and to minimize customer outages and public safety hazards that are created by increasingly severe weather. Comparing 2022 to 2023, circuits that were assigned to Frequent Outage programs experienced a 35.2% improvement in all-weather SAIFI, and a 14.0% improvement in all-weather SAIDI. When excluding major event days (MEDS), there are even greater improvements of 55.2% in SAIFI and 49.9% in SAIDI (Elliott Andahazy, 4T 984-86).

5. System Cable Replacement, and Underground Residential Distribution (URD) Replacement

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. The Cable Replacement program prioritizes and proactively replaces at-risk system cable

prior to in-service failures based on multiple factors including insulation type, failure history, system impacts, and cable loading. The Company replaced 8 miles of system cable in 2023, and plans to replace approximately 10 miles in 2024, and 11 miles in 2025. These cable replacement efforts will benefit customers through maintaining system redundancy which ensures continuing reliability, and reduced risk of lengthy outages (Elliott Andahazy, 4T 987-88, 996-97).

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. There are nearly 11,000 miles of URD cable on the system, with approximately 2,068 miles (24%) being pre-1985 (non-tree-retardant).[59] The URD program prioritizes and replaces URD cable based on multiple factors including number of failures on the circuit, and number of customers affected by those failures. The program also replaces live-front transformers with dead-front transformers (Elliott Andahazy, 4T 997-1000, 1062-64).[60]

The URD Replacement program replaced 75.3 miles of URD cable in 2023 and has replaced approximately 223 miles of URD cable from 2018-2023. URD Replacement investments for 2024 and 2025 are addressed through the IRM that was approved in Case No. U-21297 (investments are moved from Exhibit A-12, Schedule B5.4 to Exhibit A-33, Schedule X1). Customers benefit from improved reliability because the program will reduce the number of customer interruptions due to URD cable failures. Customers also benefit from a reduced risk of multiple failures and long-duration outages (Elliott Andahazy, 4T 1004-1005).

[59] "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, 4T 998).

[60] 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, 4T 1000).

AG-MNSC witness Stephens stated that he found the program did not deliver benefits to customers exceeding its costs in Case No. U-21297, the Company did not perform a BCA for the program and recommended that the Commission not include the program for the IRM in 2026 and 2027 (6T 4026-28).

Witness Stephens' maintenance of his position neglects that in Case No. U-21297, the Commission approved cost recovery for the Cable Replacement and URD Replacement programs, stating:

> The Commission finds that the Company's requested funding should be approved for inclusion in rate base with Staff's proposed 10% reduction to protect against over-projections. The Commission recognizes that regular maintenance is necessary and that faulty cables should be replaced, and DTE Electric provided evidence that multiple factors are considered in determining where replacements are necessary including vintage, number of failures, and number of affected customers, as well as safety improvements. . . . Finally, the Commission disagrees with the ALJ and does not find that it is necessary to separate expenditures by project for this program. [December 1, 2023 Order in Case No. U-21297, p 99.]

With regard to a BCA, the Company has performed three BCAs (PTMM, Strategic Undergrounding, and Overhead to Underground Services), and is moving to perform more BCAs. System cable and URD cable replacement are prerequisite infrastructure investments, however, that are foundational for the continuity of electric service. The consequences of failure are also so great (with large scale prolonged outages and the possibility of extensive system damage beyond the breaker itself), that a run-to-failure approach is not acceptable. Therefore, the investments are reasonable and prudent, and witness Stephens' suggestion of not including the URD investments in the IRM for 2026 and 2027 should be rejected (Elliott Andahazy, 4T 1062, Exhibit A-23, Schedule M13. See also section VIII. A regarding the IRM).

6. Breaker Replacement

This program replaces obsolete circuit breakers,[61] 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 SCADA capability reducing outage duration. Breakers are prioritized for replacement based on criteria that maximize these benefits. Past breaker replacements are reflected in Table 23 (at Elliott Andahazy, 4T 1009), and investments for 2024 and 2025 are addressed through the IRM that was approved in Case No. U-21297 (Investments are moved from Exhibit A-12, Schedule B5.4 to Exhibit A-33, Schedule X1). (Elliott Andahazy, 4T 1005-10, 1059-60).

AG-MN witness Stephens stated that he found the program did not deliver benefits to customers exceeding its costs in Case No. U-21297, the Company has not provided a BCA for the program, and the Commission should not include the program in the IRM for 2026 and 2027 (6T 4026-28).

Witness Stephens' maintenance of his position neglects that in Case No. U-21297, the Commission previously approved cost recovery, stating:

> The Commission finds that the replacement of obsolete circuit breakers is the type of work, like the removal of arc wire, that is necessary and lends itself to few alternatives. The Commission disagrees with the ALJ and approves DTE Electric's requested funding for inclusion in rate base but adopts the Staff's proposed 10% reduction to the company's test year request as a check on the potential for over-projections. The company provided evidence that 60% of breakers in the distribution and subtransmission systems (including substation reclosers) are beyond their life expectancy. DTE Electric provided the criteria used for selecting which breakers to replace and indicated that it plans to replace 35 breakers in 2023 and 36 in 2024. 3 Tr 543-544. While the evidentiary showing could have been more

[61] 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, 4T 1005).

> robust, the Commission believes that this is important work that needs to be done and approves the requested funding with the 10% reduction. [December 1, 2023 Order in Case No. U-21297, p 101.]

With regard to a BCA, the Company performed three BCAs (PTMM, and Strategic Undergrounding, and Overhead to Underground Services), and is moving to perform more BCAs. Breaker replacement is a prerequisite infrastructure investment, however, that is foundational for the continuity of electric service. The consequences of failure are also so great (with large scale prolonged outages and the possibility of extensive system damage beyond the breaker itself), that a run-to-failure approach is not acceptable. Therefore, the investments are reasonable and prudent, and witness Stephens' suggestion of not including the investments in the IRM for 2026 and 2027 should be rejected (Elliott Andahazy, 4T 1058-60, Exhibit A-23, Schedule M13. See also section VIII. A regarding the IRM).

7. Other Programs.

Company witness Elliott Andahazy also explained and supported the Mobile Fleet Program (4T 1010-12), Pontiac Vaults Program (6T 1012-14), Automatic Pole-Top Switch (APTS) Program (6T 1014-15), Disconnect and Switcher Replacement Program (6T 1015-16), Steel Pole Highway Crossings Program (6T 1016-17), Batteries and Chargers Replacement Program (6T 1017-18), SCADA Pole-Top Device Replacement Program (6T 1018-19), Substation Regulator Replacement Program (6T 1019-20), and Portable Generators Program (6T 1020. See also, Hill, 6T 3058).

On the last topic, the Company requests $4.5 million for Portable Generators in 2024 to purchase generators that the Company will deploy to customers to provide temporary electricity during storms (Hill, 6T 3058; Exhibit A-12, Schedule B5.4, p 13, line 28).

The AG proposed a full disallowance for a number of reasons (Coppola, 6T 3614-15). The Company disagrees as discussed below.

AG witness Coppola first reasoned that the generators could not provide heat and air conditioning. This may be true, but the generators still provide several benefits to customers, including powering medical devices for vulnerable customers, powering appliances to preserve food and allow food to be cooked (avoiding customer frustration in having to throw away and repurchase food), power sump pumps (to prevent home flooding), and enabling customers working from home to use their internet services and computer devices (Hill, 6T 3084-85).

Witness Coppola further suggested that customers would not receive a generator during the first 48 hours of a storm. This is incorrect, and apparently based on his misunderstanding of a discovery response explaining that when storms occur, the Company creates a list of all customers likely to be without power for at least 48 hours, and immediately contacts customers on this list to offer them a generator (Hill, 6T 3085; Exhibit A-52, Schedule QQ2).

Witness Coppola also asserted that demand for generators is likely to outstrip the supply. The Company has not seen any indications of this, and will monitor supply and demand, and adapt accordingly to serve customers (Hill,6T 3085).

Finally, Witness Coppola suggested that gasoline delivery could be compromised due to nearby gas stations not having power. Even assuming this situation arose, the Company has several options to ensure gasoline is available. Therefore, the Company's Portable Generators request should be approved as a reasonable and prudent way to mitigate some of the impacts of power disruptions for customers who are impacted by outages resulting from increasingly frequent and severe storms (Hill, 6T 3085-86).

b. Infrastructure Redesign and Modernization

Infrastructure Redesign and Modernization projects and programs fundamentally rebuild and upgrade the distribution and subtransmission segments of the grid. They add capacity by

converting the distribution system to a higher voltage for growing customer load, reduce outages and shorten outage restoration time by incorporating modern technology and equipment, harden the grid, improve redundancy and resiliency of the system, and increase safety. They fall into five primary areas: (1) Conversion Programs (City of Detroit Infrastructure (CODI), 4.8 kV Conversion, 4.8 kV ISO Conversion, and 8.3 kV Pontiac Conversion); (2) Subtransmission Redesign and Rebuild; (3) Strategic Undergrounding (SUG); (4) Primary Deconductoring; and (5) System Loading (Deol, 5T 1136-39, 1218); Exhibit A-12, Schedule B5.4, pp 14-16 (listing projects); Exhibit A-23, Schedule M6). The Company projects capital expense of $550.7 million in the 24-month bridge period ending December 31, 2024, and $227.0 million in the projected test year (Exhibit A-12, Schedule B5.4, p 16, line 111, columns (f), and (g)).

1. City of Detroit Infrastructure (CODI) Conversion

This program converts some of the oldest sections of the Company's grid from 4.8 kV to 13.2 kV in the core Downtown, Midtown, and New Center areas of Detroit, serving customers including commercial and multi-tenant buildings, healthcare facilities, stadiums, and universities. Redevelopment in the City of Detroit is stressing this aging infrastructure, and the Company cannot serve new customer load with existing capacity (Deol, 5T 1154-63).

The program includes (1) constructing two new 13.2 kV substations (Corktown and Island View), (2) expanding three existing 13.2 kV substations (Midtown, Alfred, and Cato), (3) decommissioning five 4.8 kV substations (Charlotte, Walker, Howard, Kent, and Gibson), (4) converting and consolidating the existing AC network system, as well as the associated overhead circuits from 4.8 kV to 13.2 kV, and (5) decommissioning the aged underground 4.8 kV and 24 kV cables in the CODI footprint (Deol, 5T 1164. See also Figure 3 at Deol, 5T 1155, showing the CODI footprint)

In Case No. U-21297, Staff supported the CODI program, but proposed disallowances using an historical calculation 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 (U-21297, Shi, 7T 4697). [62] MNSC proposed a 50% spending cut. The PFD proposed either no consideration of cost recovery for the projects (due to in-service dates beyond the test year), or no recovery (PFD, p 285). The Commission recognized the importance of this "necessary work on aging infrastructure," and therefore rejected MNSC and the PFD's extreme positions, approved the Company's proposed spending but with Staff's proposed disallowances, and noted that the Company could seek further recovery in subsequent cases, stating:

> The Commission disagrees with the ALJ and finds that the CODI program should be included in rate base albeit at the reduced levels recommended by the Staff. The Commission is not persuaded that the in-service dates should preclude this necessary work on aging infrastructure from being included in rate base. *See*, 2 Tr 208-213. As the company notes, this work encompasses "the earliest electrical grid in southeast Michigan[,]" having been constructed in the early part of the 20th century. 2 Tr 209. Due to its location, this area has been experiencing significant load growth; but due to its age, it has also been experiencing higher failure rates, and conversion is made more complicated by the presence of significant amounts of system cable. 2 Tr 209-211. The Commission finds that the Staff's method for calculating reasonable reductions to the company's projections is well supported, convincing, and prudent, and superior to MNSC's suggested disallowance. The Commission approves DTE Electric's proposed spend with $56.4 million disallowance for the bridge period and $115.9 million disallowance for the test year recommended by the Staff. *See*, 7 Tr 4696-4697. Should the company ultimately spend more on this project than is included in forward-looking rates, in can seek recovery in a future rate case proceeding upon a showing that the increased spending was reasonable and prudent. [December 1, 2023 Order in Case No. U-21297, p 111.]

Table 3 at Deol, 5T 1165-67, summarizes the projects in the CODI program. See also Exhibit A-23, Schedule M6). Capital expenditures were $49.8 million in 2022, and are projected to be $198.2

[62] Staff's Initial Brief, p 29, 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."

million in the bridge period, and $48.4 million in the projected test year (Deol, 5T 1235; Exhibit A-12, Schedule B5.4, pp 14 & 16, lines 28-36 and 79-82).

DAAO witness Koeppel recommended that the Commission "should reject or substantially reduce DTE's proposed capital spending on the CODI program, particularly in the Core Area which demonstrates higher-than-average reliability" (6T 4416). The Company disagrees because witness Koeppel's suggestion that CODI investments do not provide benefits is unjustified and based on a mischaracterization of information presented by the Company, as further discussed below (Deol, 5T 1236-39).

Witness Koeppel attempted to draw correlations between population density and electrical system reliability (e.g., 6T 4413). Instead, SAIDI performance for the CODI area is better than it is for surrounding areas because the CODI area is a predominantly all-underground area in a dense urban environment, whereas the surrounding areas are fed by overhead circuits. The CODI boundary that Witness Koeppel drew over the system (at Koeppel, 6T4415) also has significantly worse reliability in the outer edges of the geographic area where some overhead exists within the footprint (Deol, 5T 1236).

Witness Koeppel also suggested that the Company's rationale for CODI expenditures contradicts its own equity analysis (e.g., 6T 4414). To the contrary, the CODI projects were specifically developed as their own initiative due to the uniqueness of the systems in the CODI footprint, as indicated above (Kryscynski, 3T 451; Deol, 5T 1159, 1236-37). [63]

The need for project improvements relating to the CODI area's reliability is further illustrated by comparing that area to other cities with urban underground systems. The downtown

[63] 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 369-93, 448-57). See also section XI. B.

Detroit AC Network has experienced customer outages 22 times since 2016, or an average of 2.75 outages per year. This is concerning because typically, a network customer can expect to be out of service once every 58 years and experience 4% of the interruptions of a radial underground system (New York Public Service Commission, 2009, as quoted in Smith & Moffat, 2020). This illustrates how the aged infrastructure in the CODI footprint already has failure rates and reliability that drastically underperform similar systems in the industry. This trend is similar to the experiences of other utilities that have experienced catastrophic failures on their urban network systems. It is important to rebuild and maintain the system prior to the exponential escalation of large-scale failures (Deol, 5T 1163, 1238-39).

Therefore, the Company's requested recovery for CODI investments should be fully approved.

2. Other Conversion Programs

4.8 kV Conversion. This program is aimed at upgrading the aged 4.8 kV system to higher grid voltage by, among other things, building new 13.2 kV substations to add capacity to serve growing load and rebuilding circuits to address safety hazards of the 4.8 kV ungrounded system, and address deteriorating reliability performance due to aging electrical infrastructure (Deol, 5T 1140- 45). Converting all 4.8 kV substations and circuits will be a significant long-term investment. Consistent with other strategic projects and programs, conversion projects are prioritized using the GPM, which was updated in 2023. A conversion project's GPM score is driven primarily by the project's ability to address substation firm rating, circuit overloads, wire downs per overhead (OH) mile, and substation risk, plus the reliability benefits and investments in Energy Justice (EJ) communities (Deol, 5T 1145-46; Exhibit A-23, Schedule M8 DGP, section 9.3.4 Prioritization of Conversion Projects). See also generally, section V. B. 4, viii. b. 6 on System Loading.

The projects included in this case are summarized in Table 1 at Deol, 5T 1146-50. See also Exhibit A-23, Schedule M6. Company witness Deol provided additional details on two representative projects for a deeper understanding of the drivers, scope, and benefits of 4.8 kV Conversion projects: (1) I-94 Substation and Circuit Conversion (Promenade) (5T 1151-53), and (2) Lapeer – Elba Expansion and Circuit Conversion (Apollo). (5T 1153-54).

4.8kV ISO Conversion. This program relates to the Company operating some circuits at 4.8 kV 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 13.2 kV circuits, and to address deteriorating reliability performance due to aging electrical infrastructure (Deol, 5T 1169-72).

8.3kV Pontiac Conversion. This project concerns the 8.3 kV system that serves the City of Pontiac. The Company acquired the system from CMS Energy in the 1980s, and it is the only 8.3 kV system in the Company's distribution system. As an island surrounded by the 13.2 kV system, there is a high risk for stranded load in the event of a substation outage. In addition, the 8.3 kV system is aged, and replacement parts are no longer available. Therefore, the Company has developed a plan to upgrade and convert the Pontiac system to 13.2 kV as part of grid modernization, starting with upgrading the system vaults as outlined in previous rate cases and section 9.3.7 of the DGP. Benefits include improving system operability, reducing outage restoration time, and providing capacity for future needs and to better prepare the area for adoption of EVs and DERs (Deol, 5T 1173-75; Exhibit A-23, Schedule M8 DGP). Table 6 at Deol, 5T 1175, summarizes the projects included in this case. See also Exhibit A-23, Schedule M6 for additional details.

In Case No. U-21297, MNSC proposed a 50% disallowance, and the PFD (at p 290) proposed no recovery, similar to their positions on CODI. The Commission again disagreed and provided for cost recovery, stating:

> The Commission finds that the company showed that these expenditures are reasonable and prudent and approves them for inclusion in rate base. *See*, 2 Tr 196-216. The Commission is not persuaded that these projects should be cut by 50% or that the work should be excluded simply on the basis of its in-service dates. The Commission notes that MNSC testified that it does "not oppose these programs generally. All infrastructure must be replaced over time. . . ." 6 Tr 3370. The Commission agrees and finds that this replacement work should proceed apace due to the age, safety, and reliability issues presented by this equipment and the need to reduce wire downs. *See*, 2 Tr 213-214. [December 1, 2023 Order in Case No. U-21297, p 113.]

AG-MN witness Stephens did not propose any capital disallowance in this case, but he recommended that the Commission reject the Company's proposal to include conversions in the IRM for 2026 and 2027 (6T 4006-7). The Company disagrees as discussed in section VIII. Witness Stephens also made a number of criticisms about the Company's conversion programs, which are discussed below for continuity of subject matter.

AG-MN witness Stephens questioned the Company's pace of converting 4.8 kV circuits, asserting that "[a]s DTE likely built these circuits over a 50-year period from 1900 to 1950, rebuilding all these circuits in 15 years is an unreasonable aspiration" (6T 4000-4001). Witness Stephens' reference to the initial building of the 4.8 kV grid lacks relevance because it was driven by different factors than the Company's current conversion investments, which are driven by increasing electric capacity needs, system performance caused by aging infrastructure, and potential public safety hazards of an ungrounded 4.8 kV delta system. The 15-year conversion goal is also a directional target that the Company developed as part of its long-term vision for the grid, in accordance with the September 11, 2019 Order in Case No. U-20147, p 4. Ultimately, the grid will be rebuilt at a pace required to support customer needs and affordability. The conversion

investments in this case are supported by near-term drivers such as capacity needs, reliability improvements, and addressing aging and end-of-life infrastructure (Deol, 5T 1225-26).

Witness Stephens asserted that "[r]eliability improvement is not a reasonable justification [for converting to 13.2 kV] because data the Company provided in discovery in U-21297 shows the reliability of 13.2 kV circuits (as measured by system average interruption duration without major event days) was worse during 2018-2022 (124 minutes) than the reliability of 4.8 kV circuits over the same time period (97 minutes)." (Stephens, 6T 4001).

The claimed lack of reliability improvements is inaccurate. The average projected reliability improvement is estimated to be up to 90% for the conversions in this case. Witness Stephens arrived at his conclusion by examining the narrowly-defined SAIDI ex-MED. For the same period using all-weather SAIDI, customers served by 13.2 kV circuits experienced 17% better performance than customers served by 4.8 kV circuits. Witness Stephens' comparison of 4.8 kV to the existing 13.2 kV system also does not reflect the reliability improvements expected from current conversion projects, which use updated standards and specifications that will result in more reliable and resilient 13.2 kV circuits (Deol, 5T 1144, 1227-28).

Witness Stephens apparently recognized that conversion improves safety, but then dismissed that consideration, stating "[a]s stated in the section on DTE's 4.8kV Hardening program, the design of the Company's 4.8kV circuits likely increases the risk that a downed conductor will remain energized if it falls to the ground. However, this is a design condition that has existed on the Company's 4.8kV circuits since they were constructed, likely between 75 and 120 years ago" (Stephens, 6T 4002).

The Company disagrees with Witness Stephens' assessment and believes that reducing the risk associated with potential energized downed wires of the 4.8 kV ungrounded delta circuits should be a major focus and justification for converting the 4.8 kV circuits. The circuit design's

existence for 75 to 125 years is not a reasonable justification for slowing down the pace of conversions (Deol, 5T 1229).

Witness Stephens also offered his perspective on the capacity justification for converting 4.8 kV circuits (6T 4002-4003). The Company generally agrees that conversions should be prioritized based on loading; however, safety and reliability must also be considered. Witness Stephens' capacity assessment is also flawed because it is based on day-to-day loading data for one year, 2022. One must examine circuit loading trends over time, as well as the other metrics of peak capacity, and the number of substations/circuits that are over their firm rating. The Company also must maintain a capacity margin for operating the system during maintenance and trouble events. The Company prioritizes near-term conversions from a capacity standpoint where 4.8 kV substations are over firm, and where there are circuit overloads. The Company also takes into account areas where there are requests for increased electric service (Deol, 5T 1230; 2023 DGP, Exhibit A23, Schedule M8, pp 19-21).

On a somewhat-related matter, AG-MN witness Alvarez asserted that "preparing the grid for electrification, for example through conversions of 4.8 kV circuits to 13.2 kV circuits, does not appear to be an urgent need" (6T 3934). In addition to the discussion above about conversion projects addressing loading issues and improving safety and reliability, the Company further notes that another benefit to conversion is that it prepares the grid for electric vehicles (EVs) and distributed energy resources (DERs). Investments in the grid are required to prepare for the anticipated increase in EV and DER adoption (Kryscynski, 3T 443-44). See also, section VIII. C (Electric Vehicle Pilots - Charging Forward), discussing the Company's EV forecast.

Witness Stephens also inaccurately claimed that the Company lacked transparency and used the 4.8 kV CC: Almont Relief Circuit (Midas) project as an example (6T 4004-4006). The Company

instead has been transparent. Witness Stephens apparently misunderstood the information that the Company provided, as Company witness Deol explained in detail (5T 1231-34).

Witness Stephens recommended that the Commission "should direct DTE to solicit an independent expert to assess the appropriate pace of conversions . . . [and] require DTE to establish and present in its next rate case metrics, such as dollars per circuit mile converted, to budget and monitor circuit conversion costs" (Stephens, 6T 4006-4007). The Company disagrees with the recommended third-party assessment because it would be redundant to the U-21305 audit that is currently underway. The Company also disagrees with the recommendation to develop metrics because conversion projects are complex. Each project is unique and includes a number of factors such as customer density, circuit pole density, and substation layout design. Due to variations inherent in projects with very different scopes, there would be limited value in a "one-size-fits-all' metric such as the proposed dollars per circuit mile converted (Deol, 5T 1231, 1234).

In summary, Mr. Stephens' criticisms and recommendations regarding the conversion programs lack any valid basis. The record further reflects that the conversion projects will improve safety and reliability for customers, and are otherwise reasonable and prudent, so cost recovery should be fully approved.

3. Subtransmission Redesign & Rebuild

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. The Subtransmission Redesign & Rebuild program focuses on installing new station equipment and rebuilding both the overhead and underground portions of the subtransmission system. 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. For example, the Company performed an analysis that revealed that approximately one third of the circuit miles on the subtransmission system violated the Company's planning criteria. Benefits include safety improvements, improved reliability and operability, and increased capacity (Deol, 5T 1176, 1244-47; Exhibit A-23, Schedule M8, pp 101-102; Exhibit A-50, Schedules OO1 and OO2). Table 8 at Deol, 5T 1187-88 summarizes the projects included in this case. See also Exhibit A-23, Schedule M6 for additional details. The Company must also continue to maintain the subtransmission system to ensure redundancy during normal and emergency operations. The subtransmission system is aging beyond 80 years old in some areas. This coupled with ever-increasing severe weather, as well as increased loading in selected areas have led to loss of available contingency power flow paths, thus reducing redundancy and exacerbates resiliency challenges. (Deol, 5T 1243).

The Company also created a Small Projects and Reserve program to address relatively less complex issues on the subtransmission system and provide multiple benefits (safety, improved reliability and operability, and increased capacity) in a shorter amount of time (Deol, 5T 1189-91). Table 9 at Deol, 5T 1190, summarizes the projects for 2024.

In Case No. U-21297, MNSC proposed a 50% disallowance. The PFD (at p 275) recommended no consideration of projects with in-service dates beyond the test year, but no disallowance was necessary for the Company's requested amounts. The Commission essentially agreed with the PFD's conclusion of no disallowance, stating that "[w]hile not agreeing that the in-service dates are dispositive of the issue, the Commission finds the ALJ's recommendation to reject the proposed disallowances to be well-reasoned and supported by the record" (December 1, 2023 order in Case No. U-21297, p 106).

AG-MN witness Stephens recommended disallowing three projects (Tie 4105 Phase 3; Tie 4105 Phase 4; and Trunk 3509) totaling $28.15 million (6T 4020). The Company disagrees as

discussed below (Deol, 5T 1240-55, 1261-63). Witness Stephens also proposed that Subtransmission Redesign and Rebuild projects should not be included in the IRM (6T 4020). The Company disagrees as discussed in section VIII.

Witness Stephens asserted that "[g]iven that subtransmission service interruptions are such a small proportion of DTE's total service interruptions, addressing them with a large-sized Subtransmission R&R program is not effective. Further, customers are already paying for redundant design specifically to reduce the consequences of equipment failure" (Stephens, 6T 4016).

Witness Stephens neglected that when a subtransmission outage does occur, a large number of customers do not have power, often for an extended period of time. Therefore, it is critical to improve the reliability of the aged subtransmission system to prevent future interruptions with large cascading customer outages. Also, because of its critical role and the impact to the downstream distribution system, the subtransmission system requires greater design margins and redundancy to the lines feeding substations. Redundancy is also required to safely perform proactive maintenance and equipment upgrades without impacting customer service. The subtransmission system's advanced age, coupled with ever-increasing severe weather and increased loading in certain areas have led to loss of available contingent power flow paths, thus reducing redundancy and exacerbating resiliency challenges (Deol, 5T 1176, 1180, 1242-44).

Witness Stephens further asserted that "DTE's subtransmission system has likely been in its current condition (with a significant proportion of its circuits in violation of planning criteria) for several decades" (6T 4019). The Company disagrees with the indicated belief that concerns need not be addressed in the near term, and the Company can simply continue to operate as-is indefinitely without any significant consequences to customers. If the concerns are not resolved, then the system will continue to lose its ability to maintain the required redundancy to ensure grid reliability (Deol, 5T 1243-44).

Also as indicated above, the Company performed an analysis that revealed that approximately one third of the circuit miles on the subtransmission system violated the Company's planning criteria. A circuit with a thermal and/or voltage planning criteria violation has capacity limitations. Additional load cannot be added on either a temporary or permanent basis without a risk of equipment damage that can result in cascading outages, impacting a significant number of customers (Deol, 5T 1181, 1245-46).

Thermal violations occur when analysis indicates that equipment overloads will likely lead to the overheating of equipment resulting in permanent damage or failure of the equipment. Equipment can be loaded up to 100% of its normal rating, and 90% of its emergency rating. When equipment is exceeding 90% of its emergency rating, load shed (intentional customer outages) must be initiated to protect the equipment from failure due to thermal loading and overheating. In a typical case where two subtransmission lines are feeding a distribution substation and one of the lines is interrupted due to a failure or outage event, the other subtransmission line can only serve load that is up to 90% of its emergency rating on a temporary basis while the first line is restored. Trunk 359 is an example of a thermal violation where the Company had to shed load until mobile equipment was deployed (Deol, 5T 1246-48).

A voltage violation is another sub-category of planning criteria violations. This occurs when subtransmission system conditions lead to a voltage level that is outside the +/- 5% of the intended nominal system voltage, as required by the ANSI C84.1 standard. If the system voltage goes outside of this required range, then customers' electrical equipment will not function properly, and damage might result. The Northeast Area Transformer Project is an example of how a voltage violation could impact system redundancy (Deol, 5T 1249-50).

The Subtransmission Redesign and Rebuild program also improves resiliency to severe weather events (Deol, 5T 1250-51). AG-MN witness Stephens acknowledged that "[l]arger

conductor and steel poles are less susceptible to storm damage than smaller conductor and wood poles" (6T 4017). He then indicated, however, that this improved resiliency is unnecessary because "wind and ice comprised just 1.3% of subtransmission equipment outages from 2019 to 2023" (6T 4017, citing his calculations).

The Company disagrees with Witness, Stephens' indicated belief that storm damage is a de minimus consideration because it neglects that wind and ice are not the only causes of storm damage. Approximately 30% of subtransmission outages are weather related.[64] Also, although ice historically has occurred infrequently in the Company's service territory, when it happens it often results in large, catastrophic storm damage. For example, the ice event in 2023 dramatically impacted the Company's system, including subtransmission equipment. The Company has also been experiencing more frequent and increasing wind speed weather events. Thus, there is a need for a more durable and resilient subtransmission system (Kryscynski, 3T 314; Deol, 5T 1251-53).

Witness Stephens stated that "[t]he question is, on which subtransmission circuits are the risks the greatest, and how quickly should they be addressed?" (6T 4019). The answer is that the Company's subtransmission engineers prioritize projects to address thermal and/or voltage planning criteria violations based on the violation severity and customer impact. Witness Stephens was also inaccurate in suggesting that the Company does not consider alternatives. The Subtransmission Planning Engineers lead multiple technical reviews during the detailed engineering scope development phase to evaluate project options and the most cost-effective solution. These technical reviews include the evaluation of alternatives to the project (Deol, 5T 1185-86, 1253- 55; Exhibit A-50, Schedule OO3).

[64] This is calculated by adding weather-related cause codes (wind, ice, lightning, and tree) and assuming approximately ¼ of equipment failure cause codes are weather related (Deol, 5T 1252-53).

As indicated above, Witness Stephens recommended disallowance of three subtransmission projects (Tie 4105 Phase 3; Tie 4105 Phase 4; and Trunk 3509). The Company disagrees. In addition to the discussion above, these projects are supported by Exhibit A-23, Schedule M6, which provides detailed project drivers, required scope, and associated benefits for each Subtransmission Redesign and Rebuild project (Deol, 5T 1262).

See sample key details provided in Exhibit A-23 Schedule M6 for Trunk 3509:

Purpose and Necessity:	Capacity: Trunk 3509 is loaded to 100% of the equipment's summer normal rating and 109% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria. Operability: There is an Emergency Load Control scheme at PATON substation that will automatically shed load (4.1 MVA) to prevent from overloading equipment on Trunk 3509 and protect the equipment from any permanent damage.
Scope:	• Install 1 breaker • Install 2 disconnects • Install 1 relay panel • Install 733 feet of conduit • Replace 6,225 feet of cable
Benefits:	• Alleviate thermal loading violations, and the possibility of shedding customer load during a single contingency event. • 1.5 MVA of capacity created on Trunk 3509 • Improve system shutdown capability and operability.
Approximate Construction Schedule:	2021: Engineering 2022: Design 2023-2024: Construction
Total Cost:	The estimated project cost for this investment is $ 6,080,116

(Deol, Exhibit A-23 Schedule M6 for Trunk 3509)

Therefore, Mr. Stephens' proposed disallowance for the three projects should be rejected, and all Subtransmission Redesign and Rebuild projects should be approved through the projected

test year, as well as included in the IRM for 2026 and 2027 as discussed in section VIII. C (Deol, 5T 1263).

4. 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 (Deol, 5T 1191-93). In Case No. U-21297, the Commission approved historical spending, but disallowed bridge and test period recovery. The Commission essentially recognized the potential benefits of undergrounding, but indicated a desire for more extensive analysis, explaining in part regarding the Appoline pilot:

> The Commission, in this instance, was looking for a pilot with an accompanying comprehensive BCA. Undergrounding is such an expensive proposition for ratepayers, that while the Commission believes there may be instances where undergrounding is the best option, it requires a BCA to demonstrate (before that expenditure is undertaken) that undergrounding is superior to other alternatives on a quantitative basis. [December 1, 2023 Order in Case No. U-21297, pp 103-104.]

Accordingly, Company witness Deol recounted the history and lessons learned from the Appoline pilot, which concerned replacing rear-lot overhead infrastructure with rear-lot underground infrastructure (Deol, 5T 1193-95; Exhibit A-23, Schedule M11). He then addressed the shortcomings identified by the Commission, and introduced the detailed BCA for the Appoline pilot (Exhibit A-23, Schedule M13), stating:

> An initial BCA for the Appoline pilot project based on a partial subset of customer installations was presented in MPSC case U-21297, however it was inconclusive due to limited customer data. Since that time, the Company collaborated with an independent consulting firm to create an updated BCA based on methodology utilized by other utilities in other states (such as IN, OH, IL, MD, FL, and OK). This analysis uses a long-term, present value methodology to compare the customer and utility benefits to the costs associated with investment options. The Appoline underground pilot project was compared with the alternatives of PTMM and overhead rebuild. The benefits of the Appoline underground pilot project included the present value of the avoided future costs of vegetation management, PTMM, and emergent reactive issues. The model also included the benefits associated with

> the customer impacts of outages, using the Lawrence Berkeley National laboratory (LBNL) Interruption Cost Estimate (ICE) calculator. The LBNL ICE calculator is used by many utilities to approximate customers' costs of interruptions, although many including LBNL acknowledge that the model is conservative and underestimates the true costs of outages. Then a benefit-to-cost ratio (BCR) was calculated for each investment option and compared to alternatives. The detailed BCA for the Appoline pilot is provided in Exhibit A-3 Schedule M13. [Deol, 5T 1195-96.]

The results from the BCA indicated that the BCR of the Appoline pilot project was lower than overhead rebuild, but higher than PTMM.[65] This was not an unexpected result for an initial pilot with substantial costs to remediate rear ally debris, and other challenges. Learnings about these issues have been incorporated in subsequent undergrounding work (Deol, 5T 1196-97; Exhibit A-23, Schedule M11).

The Commission also indicated a desire for a further "discussion of health, safety, reliability, vulnerability, and distribution issues" (December 1, 2023 Order in Case No. U-21297, p 103). Accordingly, Mr. Deol further explained the Appoline BCA does not include other important benefits:

> Significant benefits of safety and resiliency for customers are not included in the financial BCR of the Appoline pilot project. With the rear lot overhead 4.8 kV conductors removed, the wire down hazard for this section of the distribution circuit has been eliminated. Furthermore, by undergrounding the overhead lines, the community and customers also reaped the significant benefit of greater resiliency against the more frequent and severe extreme weather events that could lead to prolong [*sic* prolonged] outages. . . . [explanation that the ICE calculator might underestimate interruption costs due to increased reliance on "cloud" computing and other technology omitted]. Both of these benefits, safety and resiliency, are not easily quantifiable in a way that matches present day customer needs or impacts. The Company will continue to collaborate with the MPSC and industry stakeholders to determine the appropriate way to quantify these benefits. [Deol, 5T 1197-98.]

The Company has also developed a project to underground portions of the STLUS DC116 circuit in the Buffalo Charles Neighborhood to 13.2 kV capable front-lot underground residential

[65] A higher BCA indicates that there are more benefits than costs (Deol, 5T 1196).

distribution infrastructure, and remove the aged 4.8 kV overhead rear-lot distribution equipment, as well as PLD/arc wire. This is a bold initiative to underground approximately four miles of residential distribution lines using front-lot construction (an enhancement from the rear-lot scope of Appoline, consistent with peer utilities and evolving practice) in a mature urban neighborhood with the intent of capturing additional benefits of joint gas and electric work. The project is expected to be complete by the end of 2024 (Deol, 5T 1198, 1200-1201).

The Company selected the Buffalo-Charles neighborhood for this project based on criteria including wire downs per mile (safety), sustained and momentary outages for the circuit (reliability), impact to the community (energy justice), and construction costs. An urban environment was selected mainly based on the priority of safety (eliminate the hazards associated with 4.8 kV ungrounded delta system rear-lot construction), and to improve storm response for resiliency by reducing the number of customer services down (Deol, 5T 1203). Plus, this location was attractive due to synergies of working with DTE Gas, which will benefit customers through lower costs and less disruption (Deol, 5T 1199). The Company also engaged customers and other stakeholders in the project (Deol, 5T 1199-1200; Exhibit A-28, Schedule R1 reflects that the Detroit Mayor's office is very supportive of this project because it will improve the quality of life for its residents through improved safety, resiliency, and reliability).

The Company conducted a BCA for the Buffalo-Charles project using the same approach that it used for the Appoline project (Deol, 5T 1201; Exhibit A-23, Schedule M13). The BCA results (lower than overhead rebuild, but nearly equivalent to PTMM) were similar to Appoline, and again were not unexpected because the Company is still in the early stage of undergrounding pilots. The Company believes that actual project costs may come in lower with rigorous project management, and project efficiencies due to greater pilot experience. Also, like the Appoline pilot project

(discussed above), the BCA for the Buffalo-Charles project does not include significant benefits of safety and resiliency for customers (Deol, 5T 1201-1202).

AG-MN witness Stephens asserted that undergrounding is expensive and "underground lines are subject to reliability risk from flooding and careless excavation, and subject to safety risk from both excavation and contact voltage. In short, undergrounding is not the panacea many perceive it to be," and recommended full disallowances of $15.64 million in 2024 and $16.2 million in 2025 (6T 4025-26).

The Company disagrees. In addition to the discussion above, Company witness Deol recounted that the Company started the underground pilot project because it was asked to explore pilot projects to eliminate 4.8 kV ungrounded rear-lot overhead infrastructure and its associated hazards (January 18, 2019 Order in Case No. 20169, p 4). The Company remains interested in undergrounding because it offers a unique set of benefits to customers, including eliminating the safety risk associated with downed overhead equipment, reducing emergent reactive costs, and being the most resilient option for severe weather-related events. Local governments have also indicated an interest in undergrounding, and the Company has been engaged with Ann Arbor in this regard. It also bears emphasis that the Appoline and Buffalo-Charles projects are pilots from which the Company can develop processes and gain efficiencies so it can determine when and where this design option can be used most effectively. Witness Stephens' assertions of reliability and safety concerns are also inaccurate because, for example (1) underground cable and equipment are specifically designed to be able to withstand flooding, and (2) using 2023 all-weather data, completely undergrounded circuits had 77% better SADI performance than completely overhead circuits. Also, the risk from careless excavation is very low compared to the risk associated with a downed conductor. Therefore, the Commission should approve the Company's requested funding (Deol, 5T 1263-66, 1269).

5. Primary Deconductoring

Primary Deconductoring is the removal of unneeded or underutilized infrastructure such as aged small-sized primary wire, PLD arc wire, overhead (OH) transformers, and other pole top equipment in abandoned or blighted neighborhoods. In addition, where necessary, the Company will reconductor secondary wires and upgrade transformers and other pole top equipment, and install equipment in truck-accessible locations, where feasible. The Company completed pilots on two circuits in 2023. Based on the success of those pilots, the Company has rolled primary deconductoring into the 4.8kV Hardening program and 4.8 kV Conversion projects, where applicable (Deol, 5T 1205-1206).

6. System Loading

System overloads occur on a circuit or substation when there is not enough capacity to meet customer demands and still maintain grid operation within equipment operating ratings. Capacity needs are analyzed for two conditions: normal state and contingency state.[66] To meet the two capacity needs, most components and equipment have two ratings: day-to-day and emergency. These ratings are calculated to maintain the viability of an asset throughout its expected useful life. Operating equipment above its designed ratings can cause immediate failure or accelerate end-of-life, and is considered an overload. The Company's definitions for day-to-day rating, emergency

[66] The **normal state** exists when all equipment and components are in service and operating as designed. The **contingency state** exists when there is either a temporary, planned equipment shutdown, or the unplanned loss/failure of a component of the electric power system (e.g., transformer, cable, or breaker). Under contingency state conditions, equipment in the rest of the system may see an increase in loading to compensate for the out-of-service equipment, delivering additional power above normal state (Deol, 5T 1206).

rating, and substation firm rating are consistent with industry definitions such as those available from National Electrical Reliability Corporation (Deol, 5T 1206-1207).[67]

It is reasonable and prudent to address system overloads because they stress equipment and reduce useful life, as well as limit jumpering capabilities to adjacent circuits to support customer reliability during outage events. This prolongs outages because the failed equipment must be replaced to restore power to customers, and also increases the probability of emergent failures leading to outages. System overloads also inhibit the Company's ability to serve new customers and provide the ability for existing customers to expand (Deol, 5T 1210-11).

The Company forecasts and mitigates system overloads by conducting an annual Area Load Analysis (ALA) on all distribution circuits and substations to determine where there are overloads on the system. Based on a study of historical ALA's, approximately one-third of distribution substations have loading constraints. This includes substations operating over their firm ratings and/or circuit equipment working near or over its day-to-day rating during peak hours (Deol, 81).

System Loading projects to alleviate stress on the system and reduce potential failures are summarized in Table 10 (at Deol, 5T 1212-15), with additional details in Exhibit A-23, Schedule M6. Benefits include improved reliability, increased capacity to serve new and existing customers, and maintaining/improving system operability by restoring/creating jumpering capabilities and removing aged equipment from the system (Deol, 5T 1211, 1215). Projects are prioritized based on

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[67] The **day-to-day rating** (for normal state conditions) is the load level at which the equipment can be operated for its expected life span.

The **emergency rating** (for contingency state conditions) is typically higher than the day-to-day rating, and indicates the load level at which the equipment can operate for short periods of time only.

Substations also have a **firm rating**, which is the maximum load that the substation can carry under a single contingency condition, and is based on the lowest emergency rating of any substation equipment that is required to serve the load, such as incoming subtransmission fed, transformer, and secondary cables (Deol, 5T 1207-10).

how they address five factors: (1) substation equipment overload, (2) substation over firm rating, (3) circuit equipment overload, (4) strong load growth, and (5) circuits over 8 MVA for 13.2 kV circuits and 3 MVA for 4.8 kV circuits (Deol, 5T 1217; Exhibit A-23, Schedule M8).

These projects add capacity to the distribution system, and typically include construction of new substations, expansion of current substations by installing additional transformers, replacing existing transformers, installing new switchgear lineups, creating new distribution circuits, reconductoring circuits, converting circuits to higher voltage and transferring load once additional capacity has been created. Many areas identified in the priority ranking for system load relief are addressed as part of the CODI, 4.8kV Conversion, or 8.3kV Pontiac Conversion programs. Load relief needs that are not included in those programs are part of the System Loading projects category (Deol, 5T 1216-17).

c. Technology & Automation

The Technology & Automation pillar consists of Grid Automation and Operational Technology (OT). Grid Automation is focused on the physical technology infrastructure needed to support the efficient control and operation of a modern distribution grid. OT is a set of enabling technologies that interact closely with Grid Automation and are tailored to support its objectives. Table 1 (Hartwick, 4T 636), Table 5 (Hartwick, 4T 722), Table 9 (Hartwick, 4T 769), Table 10 (Hartwick, 4T 786), Table 11 (Hartwick, 4T 803), and Table 12 (Hartwick, 4T 806) introduces programs and projects, and where details of capital investments can be found in Exhibits A-12, Schedule B5.4, and A-23, Schedule M7 and M8.

Grid Automation covers four key areas: (1) Distribution Automation, (2) Grid Automation Telecommunications, (3) Conservation Voltage Reduction (CVR)/Volt-Var Optimization (VVO),

and (4) Non-Wires Alternatives (NWA) pilots, as further discussed in sections 1-6 below (Hartwick, 4T 633).

Operational Technology covers five key areas: (1) Grid Management, (2) Distribution Planning, (3) Work Management and Scheduling, (4) Asset Management, and (5) Mobile Technology, as further discussed in sections 7-11 below (Hartwick, 4T 633, 714-20).

1. Distribution Automation

Distribution Automation (DA) uses digital sensors and switches with advanced control and communication technologies to automate feeder switching, monitor voltage and equipment health, and manage voltage and reactive power. Automation improves the speed, cost, and accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers (Hartwick, 4T 637, 835, 873). [68] Distribution Automation has a high GPM rating due to (1) the safety benefits associated with de-energizing downed wires, (2) the reliability benefits associated with the reduced number of customer interruptions and the reduction of outage durations, and (3) the improved operational efficiencies associated with improved system monitoring and control (Hartwick, 4T 642, 835).

DTE Electric's Distribution Automation program is composed primarily of pole-top recloser deployments (Hartwick, 4T 638, 642-43). Following the severe storms that impacted the Company's service territory in early 2023, the Company reviewed outage events and the duration of restoration, and determined that extensive circuit automation was required to improve reliability performance for customers. As part of this expanded focus, the Distribution Automation Program was broadened to encompass the entire distribution grid. The Company also recognized that deploying remotely-operated SCADA-enabled reclosers on circuits will deliver most of the benefits

[68] See also, Department of Energy (DOE) reports regarding distribution automation (Exhibits MEC-59 and MEC-60).

associated with the Substation Automation Program at a significantly accelerated pace. Therefore, funding for substation automation was reduced and redirected to Distribution Automation investments, which also supported greater alignment and bundling opportunities within the scope of work. With the expanded scope of Distribution Automation and the refined ability to prioritize circuits to automate using a prioritization tool, the Company will combine 4.8 kV circuit automation, 13.2 kV circuit automation, substation automation, and circuit rebuild for automation into a single focused Distribution Automation Program (Hartwick, 4T 643-44).

Investment for recloser installations in 2024 will continue to focus on the 4.8 kV distribution system, based on standards and design work that was completed in 2023. The 2024 Distribution Automation Plan consists of the investments included in the IRM in Case No. U-21297 (63 circuits and 189 reclosers), plus an additional 96 reclosers that are expected to improve 32 circuits on the 4.8 kV distribution system. The work is expected to address ground detection and isolation, with benefits including a 45% reduction of SAIDI on impacted circuits, reducing system SAIDI by 9 minutes. Engineering and design work will also be completed in 2024 for 240 reclosers covering approximately 80 circuits to be constructed in 2025. In 2025, 578 reclosers across an estimated 242 circuits will be constructed based on the prioritization model developed in 2023. The planned work for 2025 is expected to address ground detection and isolation for 281 circuits at 73 substations, and is expected to reduce SAIDI on impacted circuits by 47%, reducing system SAIDI by 45 minutes. Also in 2025, 480 reclosers and 160 circuits are expected to undergo engineering and design for 2026 construction (Hartwick, 4T 644-46).

AG-MN witness Stephens recommended that "the Commission should require the Company to develop a benefit-cost model to govern Distribution Automation deployment on a circuit-specific basis . . . [and] until a circuit-specific Distribution Automation model can be developed, I recommend the Commission limit the Distribution Automation deployment budget to the annual

amount the Commission approved in U-21297 ($27.167 million less a 10% reduction recommended by Staff). (Stephens, 6T 4024). These recommendations should be rejected for lack of foundation and merit as discussed below.

Witness Stephens asserted that "DTE provides no measurable safety basis to support the reasonableness and prudence of" its investment request (6T 4023). To the contrary, as indicated above Distribution Automation includes start-of-circuit reclosers on the 4.8kV circuits that provide new capability to detect when a ground occurs, and the ability to isolate the grounded circuit, allowing the Company to quickly detect and mitigate potential safety hazards due to energized downed wires through automated isolation. These benefits will apply to the 95 circuits being automated in 2024, which have an average of 16 downed wires per year, and the 149 circuits being automated in 2025, which currently have an average of 17 downed wires per year. The Company also submitted the Distribution Automation Prioritization tool in discovery, showing the historical wire downs associated with each circuit (Hartwick, 4T 641, 644, 826-27, 864-65, 880; Exhibit A-53, Schedule RR2).

Witness Stephens stated that "the energized wire down risk on DTE's 4.8 kV circuits has existed for the last 75-100 years, since the circuits were constructed. As automated switches have been commercially available for more than a decade DTE's sudden sense of urgency is unconvincing and warrants scrutiny" (6T 4023).

Witness Stephens apparently had an incomplete understanding in suggesting that something is amiss. Although automated switches have been available for years, the ground detection capability has recently been enabled by advancements in the SEL-651R relay. The G&W Viper recloser with the SEL-651R relay is now able to detect and isolate grounds on 4.8 kV circuits, mitigating potential safety hazards, which the Company believes is important (Hartwick, 4T 827).

Witness Stephens mistakenly stated that "[a] 4.8 kV switch cannot be used on a 13.2kV circuit . . . [so the Company's move to 13.2kV] will render money spent on automated 4.8kV switches largely wasted" (6T 4023). The Company instead purchases and installs reclosers that can be used on both the 4.8 kV and 13.2 kV systems, so investments in reclosers today will be able to continue to be used when circuits are converted from 4.8 kV to 13.2 kV (Hartwick, 4T 828).

Witness Stephens also asserted that Distribution Automation has five "drawbacks," first stating that "[a]utomated switches may operate incorrectly, requiring crews to drive from switch to switch anyway" (6T 4021). This is a remote possibility. The G&W Viper is an industry-proven and reliable device (Hartwick, 4T 828).

Witness Stephens' second alleged drawback was that "[i]n storm situations, where damage is widespread, intact circuits from which to reroute power may not be available, negating Distribution Automation value" (6T 4021). To the contrary, during storm situations where damage may be widespread, reclosers are well suited to automatically identify and isolate damaged areas without intervention, thus enabling very fast restoration for portions of circuits and freeing up crews to perform other restoration jobs (Hartwick, 4T 829).

Witness Stephens' third alleged drawback was that "[t]he switches are costly, and the law of diminishing returns applies; in my experience, one tie line/switch per circuit is typically optimum, but I have observed investor-owned utilities install automatic switches beyond the point of diminishing return" (6T 4022). The apparent concern about overbuilding is misplaced because the Company's plan is to reduce the number of customers impacted by outages and eliminate safety concerns due to potential energized downed wires. The optimal number of devices installed on each circuit depends on the circuit's specific characteristics (Hartwick, 4T 830).

Witness Stephens' fourth alleged drawback was that "Distribution Automation is most cost-effective when tie lines between circuits have already been built . . . Care should be taken to ensure

tie lines are not being built where the benefits fail to outweigh the costs" (6T 4022). In addition to the discussion above, the Company does not plan on building tie points on every circuit that does not already have tie points, but instead plans to evaluate each circuit individually to identify if a tie point needs to be established and automated (Hartwick, 4T 641, 831).

Witness Stephens' fifth alleged drawback was that "Distribution Automation is a solution that addresses a symptom (service interruptions), not root causes (such as vegetation contact). The bottom line is that Distribution Automation is not a cure-all and is only appropriate for some circuits" (6T 4022). That is literally true, but makes no relevant point. Distribution automation has been utilized across the industry, and has been proven to be an effective reliability-improvement strategy.[69] The Distribution Automation program is designed to address the unique characteristics of the Company's system, and provide substantial benefits by reducing the number of customers impacted by an outage, shortening outage duration, and mitigating potential safety hazards when there has been an outage on the system (Kryscynski, 3T 577-78; Hartwick, 4T 637-38, 646, 832).

The Company also disagrees with Mr. Stephens recommendation to develop a cost-benefit model to govern deployment on a circuit-specific basis because the Company already has the Distribution Automation Prioritization tool, which uses historical reliability and safety data (wire downs), along with the unique topography of each circuit to determine safety and reliability benefits (measured as number of potential live wire downs avoided, and customer minutes of interruption) that Automation will provide for each specific circuit. The tool assigns points to each circuit based on four key weighted benefit criteria, and divides the points by the estimated circuit investment dollars. The circuits are then ranked by points per dollar, which the Company uses to prioritize selection of circuits for Distribution Automation. For 2025, projected benefits are from addressing

[69] For example, a U.S. Department of Energy (DOE) report published metrics showing that investments in distribution automation improved reliability by reducing customers affected by outages and outages duration (Hartwick, 4T 835).

ground detection and isolation for 147 4.8 kV circuits, which have an average of 17 downed wires per year, reducing system SAIDI by 45 minutes (47%). The Company also plans to enhance the tool as part of the Company's overall effort to further advance cost-benefit analysis. Therefore, Mr. Stephens recommendation is unnecessary and would duplicate the Company's already-extensive efforts (Hartwick, 4T 833-36).

There is similarly no merit in Mr. Stephens' recommendation to limit the Distribution Automation budget to the annual amount that the Commission approved in Case No. U-21297 ($27.167 million less a 10% reduction recommended by Staff). As discussed above, the Company's planned Distribution Automation investments provide proven and compelling safety and reliability benefits to customers, and the Company's Distribution Automation Prioritization tool appropriately prioritizes circuits based on benefits per dollar. The prioritized investment in this case is also a "no-regret" investment that the Company should pursue aggressively because we are in an early stage of the automation journey that will take many years to implement (Hartwick, 4T 837).

The Company has demonstrated that the investments provide benefits to customers and are otherwise reasonable and prudent. Therefore, the Company's funding request should be approved, and all contrary and additional proposals should be rejected.

2. Grid Automation Telecommunications

Grid Automation Telecommunications refers to the use of telecommunications technology in the automation of electrical power grids. Through 2025, the Company's Grid Automation Telecommunications investments are focused on expanding the backhaul network, which serves as the central communication backbone of the Company's infrastructure, connecting different sites, such as generators, switching stations, substations, and control centers. The center of the Company's telecommunications system is a fiber ring. The Company is expanding the backhaul

network with additional fiber to connect critical assets and provide enhanced capabilities. Fiber installations are expected to continue into 2028 (Hartwick, 4T 647-50, 674).

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). The Company did so in Case No. U-21297, where the Company presented evidence about, among other things, the Company's plans to install approximately 630 miles of fiber (Case No. U-21297, 5T 2760-61). The PFD found that "DTE has failed to support the reasonableness and prudence of its decisions," apparently because these 630 miles were more than the 500 miles of fiber that the Company indicated that it planned to install in Case No. U-20836 (U-21297 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. [U-21297 PFD, p 311.]

The Commission agreed, stating:

> The Commission agrees with the ALJ's observations regarding the shortcomings of the evidence in support of this proposed expenditure. The Commission finds the ALJ's recommendation to fund the bridge period but not the test year to be well-reasoned and supported by the record and adopts the ALJ's findings and conclusion on this issue. *See*, PFD, pp. 309-311.The Commission notes that the Company may seek this funding in future rate cases with adequate record support. [December 1, 2023 Order in Case No. U-21297, pp 121-22.]

Accordingly, Company witness Hartwick presented extensive testimony on this topic (4T 647-74). In addition to the discussion above, she explained key drivers of the Company's investment (4T 650-52), details regarding the Company's investment plan (4T 652-54), and customer benefits (4T

654). She also presented highlights from investments that were completed in 2022 and 2023 (4T 668-69), and plans for 2024 and 2025 (4T 669-71), and beyond (4T 674).

The Company requests $35,738,000 of investment beyond prior rate case approvals to continue investments in this vital part of building the grid of the future ($2,262,000 for the 11 months ending November 30, 2023; $1,576,000 for December 2023; $16,900,000 for 2024; and $15,000,000 for 2025). (Hartwick, 4T 840).

AG-MN witness Stephens recommended disallowances of $16,900,000 for 2024 and $15,000,000 for 2025, relying only on witness Alvarez's testimony (Stephens, 6T4028-29). Witness Alvarez inconsistently (and with no explanation) recommended "that the Commission disallow Telecommunications Plan costs incurred in 2022 and remove Plan spending from the 2023-2024 bridge period and 2025 test year" (Alvarez, 6T 3978).

The scope of the discussion is controlled by the Commission's prior decisions (outlined above). In Case No. U-21297, the Commission approved $14,206,000 for 2022, and $17,508,000 for the 11 months ending November 30, 2023. Therefore, the Company is not requesting these previously-approved investments in this case, and there is no merit in Mr. Alvarez's suggestion for a retroactive disallowance (Hartwick, 4T 839). See also the discussion in section III above. Mr. Alvarez also suggested three reasons for a cost disallowance, which lack merit as discussed below.

With regard to the Case No. U-21297 PFD's criticism (at p 311, quoted above) that the Company should "provide a proper analysis of alternatives," Company witness Hartwick presented an extensive discussion regarding what technology options the Company considered (4T 655-662). In general summary, the Company determined that private fiber was the best investment for the 2024 and 2025 project scope because fiber-optic networks offer unmatched bandwidth, speed, reliability, security, suitability for backhaul of other networks, and resilience to interference. Fiber-optic networks also provide significantly higher data transmission speeds and bandwidth essential

to support grid automation and scalability for the evolving demands of grid modernization initiatives (4T 663-64). The Company's subject matter experts (SMEs) also performed a qualitative analysis based on several reliability, lifecycle, and initial cost factors, resulting in private fiber being the best option (summarized in Figures 3-5 at Hartwick, 4T 665-6).

1 **Figure 3 Alternatives Compared Using Reliability Factors**

	Public Cellular	Private LTE	Microwave/ Wimax	Wireless Mesh	Leased Fiber	Private Fiber
Bandwidth						
Low Latency						
Network Control						
Prioritization and Quality of Service (QoS)						
Security						
Maintenance Window Scheduling						
Disaster Recovery						
Control of Communications During Emergency						
Protection Against Interference and FCC Decisions						

Figure 4 Alternatives Compared Using Life Cycle Factors

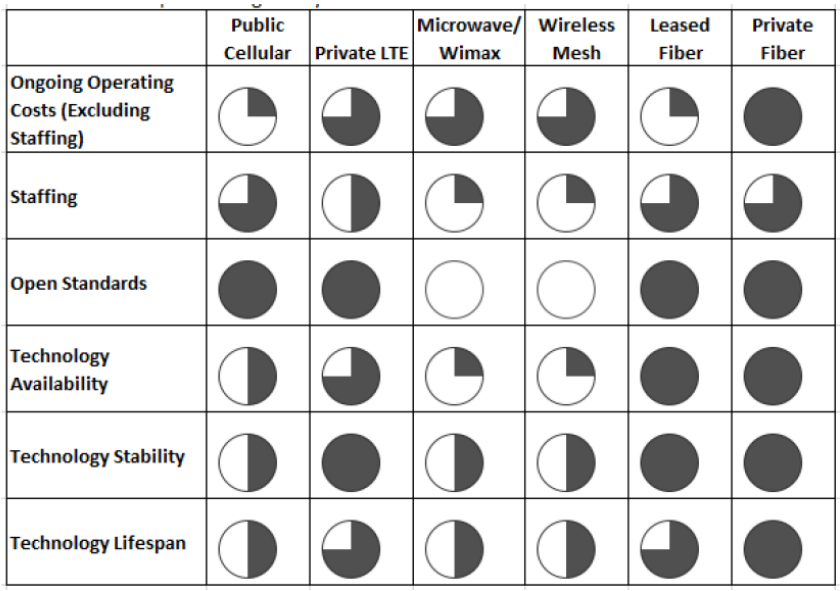
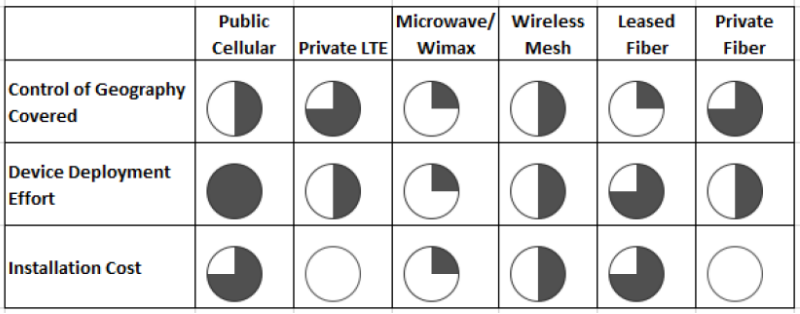


Figure 5 Alternatives Compared Using Initial Cost Factors



(Hartwick, 4T 665-666)

Ms. Hartwick explained how fiber is also more resistant to interference than wireless technologies (4T 666-67), and why the Company's ownership and operation of a private network provides the Company with greater control and flexibility as compared to leasing from existing fiber providers (4T 667-68).

Ms. Hartwick also recounted this testimony and provided discussion on rebuttal (4T 845-47), demonstrating the lack of merit in witness Alvarez's claim that cost recovery should be disallowed based on his incorrect allegation that the Company "has not complied with the Commission's Order to analyze alternatives to its Plan" (Alvarez, 6T 3978).

Witness Alvarez further asserted that 'the "Company makes two critical presumptions in support of its Plan. These include: 1) that many technologies require real-time communication; and 2) of all available options, Company-owned options provide the best combination of speed, control, security and reliability" (Alvarez, 6T 3974).

Ms. Hartwick explained that real-time communications are required to operate technologies in a modern grid due to "latency" requirements (4T 853-54), and that the Company did not presume that Company-owned options provide the best combination of alternatives, but instead evaluated various technologies leading to the conclusion that Company ownership is the best alternative, as indicated above and further detailed in the record (Hartwick, 4T 655-68854-55; Exhibit A-19, Schedule I1.1).

Ms. Hartwick also explained that the project scope changed from 500 miles of telecommunications fiber in Case No. U-20836 to 630 miles in Case No. U-21297 because Case No. U-20836 only covered miles through 2023, and Case No. U-21297 also included miles through 2024. This Case No. U-21534 now includes miles through 2025. Initial estimates of routes created at the engineering level have also been updated for final route design, considering constructability, permitting, crossings, and accessibility of the path, which results in some routes being longer and some routes being shorter. The updated scope also incorporated other projects, resulting in more robust and efficient work (4T 672-73).

The Company is also effectively controlling costs. For example, competitive bidding has reduced the per-mile cost by an average of 35% (Exhibit A-19, Schedule I1.2). This and other cost-control measures have allowed the program to maintain a design target of $55,000 per installed mile of fiber and, on average, consistently achieve that benchmark or better (4T 673).

Witness Alvarez suggested that cost recovery should be disallowed because the 2025 investments cannot be evaluated without understanding the entire plan (Alvarez, 6t 3973-74, 3978).

To the contrary, the Company explained in testimony (as well as in response to discovery, Exhibit MEC-8) that there is a clear distinction between the investments in this case and those that are contemplated beyond 2025. The investments in this case are to connect critical sites (such as generation sites, subtransmission stations, substations, service centers, and communications towers) with high-speed, high-bandwidth, and reliable connection. Witness Alvarez ignored the benefits of providing connectivity to critical sites, and failed to acknowledge that there are current benefits from fiber standalone investments, such as optionality and flexibility for the future. For the investments beyond 2025, the telecommunications plan will shift focus and scope of investments to remaining substations and last-mile investments that will be presented in the 2025 Distribution Grid Plan (DGP) and the next rate case (Hartwick, 4T 651-54, 674, 841-43).

Witness Alvarez's related assertion that the Company's 2023 DGP "provides no additional information on the Telecommunications Plan" (6T 3973) is similarly inaccurate, as Ms. Hartwick explained, citing relevant portions of the DGP (Hartwick, 4T 843-44; Exhibit A-23, Schedule M8). Ms. Hartwick concluded her response to witness Alvarez's claimed lack of information to evaluate 2025 investments with the following summary proving otherwise:

> Testimony, [Hartwick, 4T 651-54], segregates the plan into three general phases. (1) Installation and commissioning of the fiber backbone to critical sites will continue through 2025. (2) Investments in 2026 through 2028 will focus on extending of the backhaul network to next tier locations that cannot be sufficiently served by existing deployed technologies or currently do not have communications capabilities. (3) Finally, future investment beyond 2028 in grid telecommunications will focus on building out the last mile network to pole top devices.
>
> For the instant case, the first phase, the installation of the backbone to critical sites, will run through the end of the test year—2025. A listing of more detailed work scope planned and installed between 2022 and 2025 is listed on [Hartwick, 4T 668-71]. Additionally, exact routes were provided in . . . Exhibit MEC-8, for 2024 and 2025. [Hartwick, 4T 844.]

Witness Alvarez's final reason for his proposed disallowance was the contention that "DTE has not developed a benefit-cost or make vs. buy analysis that supports its spending or plan" (6T 3978). To

the contrary, the Company provided the make vs. buy study characteristics that Mr. Alvarez suggested to support its investments, as reflected in Table 2 at Hartwick, 4T 849 (Hartwick, 4T 656-62, 666, 847-48; Exhibit A-19, Schedule I1.1).

Table 2. Make vs. Buy Characteristics

Characteristics Evaluated	Inclusion in U-21534
Pros and cons of technical characteristics	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Pros and cons of Operational characteristics	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Pros and cons of Cybersecurity characteristics	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Pros and cons of Reliability characteristics	Figure 3 on page SMH-39 and Exhibit A-19 Schedule I1.1
Risks	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Initial Cost	Figure 5 on page SMH-40
Lifetime Cost	Figure 4 on page SMH-40

(Hartwick, 4T 849)

Witness Alvarez's claims of a need for more details, such as "the frequency at which commands issued through the public carrier's network failed" and "the consequences to customers (in dollars) of these service interruptions" (Alvarez, 6T 3976-78) are impractical because they would likely require the construction and operation of parallel utility-owned and third-party telecommunications systems (Hartwick, 4T 851). Witness Alvarez also acknowledged that the Company "does not possess the data needed to inform the development of such a tool" (Alvarez, 6T 3977).

Witness Alvarez further recommended that the Commission "order the Company to solicit an independent expert to complete a comprehensive analysis . . .[and] order the Company to complete a tool that appropriately identifies the best alternative to employ in various situations and circumstances" (Alvarez, 66T 3978). Witness Alvarez's suggestions for a total of four simultaneous and redundant analyses are unnecessary and inappropriate. The Company provided a

comprehensive analysis of alternative technologies for connecting critical distribution sites in accordance with the Commission's Order in Case No. U-21297, supporting investments through 2025. The Company is also committed to developing a benefit-cost analysis for determining deployments beyond 2025. No additional analysis is necessary (Hartwick, 4T 655-68, 674, 849-50, 853).

Therefore, Grid Automation Telecommunications is a reasonable and prudent investment that should be fully approved.

3. Conservation Voltage Reduction (CVR)/Volt Var Optimization (VVO)

The Company initially began evaluating CVR/VVO as a generation alternative to reduce peak demand and energy consumption as part of the Company's IRP that the Commission approved in Case No. U-20471.[70] The Company continues to implement and evaluate CVR/VVO because it provides a benefit to the distribution system and a generation alternative through reduced demand and energy consumption. Initial pilots were conducted on six circuits in 2020-2022 (the Company temporarily paused the program in 2022 and 2023 to align it with advancements in ADMS, but engineering, design, and replacement work continued). In 2024, 22 circuits will be upgraded for $2.5 million (Hartwick, 4T 675-76).

In 2025, 22 circuits are expected to be upgraded for $2.5 million. The 2025 scope of work also includes a Capacitor Replacement Program ($5.6 million to replace 737 capacitor controls), which brings the total cost for 2025 to $8.1 million. This targeted capacitor replacement program

[70] VVO manages system-wide voltage levels and reactive power flow to achieve one or more specific operating objectives, which can include reducing losses, managing circuit level voltage, optimizing operating parameters, and/or optimizing power factors. CVR, as one of the VVO options, is designed to maintain customer voltage down to the circuit level in the lower portion of the allowable voltage ranges, thus reducing system losses, peak demand, or energy consumption (Hartwick, 4T 674).

is a one-time investment to replace end-of-life and failed capacitor controls with new SCADA-enabled controls that will allow these units to be integrated across the CVR/VVO program. (Hartwick, 4T 676-77).

4. Non-Wires Alternatives (NWA) Pilots

NWAs are defined (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.

The Commission further 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). Accordingly, the Company developed a suite of NWA pilots utilizing different technologies and addressing different grid concerns. The Commission approved the following projects in its December 1, 2023 Order in Case No. U-21297: O'Shea (p 127), Omega (p 128), Mobile Battery Trailer (p 128), Fisher (p 129), Port Austin (p 128), and Veridian (p 130).

There are nine NWA pilots as shown in Table 2 of Ms. Hartwick's direct testimony (4T 680).

Table 2 NWA Pilots Use Cases, Technologies, and Objectives

Use Case	Pilot	Technology							Objective
		EWR	DR	Storage	Solar	BTM DER	EV Charging	Microgrid	
Voltage Mitigation	1. O'Shea			✓					· Test effectiveness of storage to address voltage instability due to intermittent solar
Portable Battery	2. Mobile Battery Trailer			✓					· Test use of energy storage in place of traditional portable generators
Sub-transmission Loading	3. Omega			✓					· Deploy storage to address subtransmission loading · Install battery that can be re-located
Substation Loading	4. Hancock *(Completed)*	✓							· Initial pilot to test geo-targeted EWR and develop DER Estimating tool
	5. Fisher	✓	✓						· Test geo-targeted EWR/DR costs · Measure implementation timing
	6. Port Austin			✓	✓			✓	· Test solar and storage to address substation capacity · Test redeployment of stationary battery from Omega
Customer Load and DER Control	7. Veridian		✓	✓	✓	✓	✓	✓	· Develop secure and effective methods to interface and control behind the meter (BTM) DER in conjunction with utility scale DER
EV Charging	8. EV Demonstration at ACM						✓		· Develop control algorithms and conduct testing on an extreme fast charger and its interfaces as well as develop cyber secure smart charge management capabilities for Department of Energy
Reliability	9. Adaptive Networked Microgrids			✓	✓	✓		✓	· Develop and test the use of adaptive networked microgrids to improve customers' reliability and increase the benefits of NWA deployments

(Hartwick 4T 680)

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, and Schedule B5.4.9; and Exhibit A-23, Schedule M7. The pilots that the Company is currently pursuing are building blocks, which will form a foundation for future NWA projects (Hartwick, 4T 678-81). No party proposed any disallowance for certain pilots, but for completeness, Company witness Hartwick provided updates on the progress that has been made, and the remaining work to be done.[71]

[71] The O'Shea pilot involves interconnecting a 1MW (1 hour) Battery Energy Storage System (BESS) at the O'Shea solar park to address power quality concerns due to the intermittent nature of solar generation (4T 681-82).

The EV Charging Demonstration at ACM (American Center for Mobility) concerns the Company's investments in several different EV charging technologies and projects to learn how various technologies will impact the grid (4T 690). The Commission previously declined to approve requested funding, stating:

> The Commission notes that in the November 18 order [in Case No. U-20836], pp. 159-161, the Commission approved only 10% of the requested funding for this project. Based on the record in the instant case, the Commission is not persuaded to approve additional funding at this time, the Commission agrees with the Attorney General's assessment of the technology as currently so experimental as to be premature for funding by ratepayers. *See*, 6 Tr 3680-3681. Further, it is unclear what benefits—if any—would be available to DTE Electric's customers other than ACM, making it difficult to justify the reasonableness and prudence of having all customers pay for this pilot. [December 1, 2023 Order in Case No. U-21297, p 131.]

Company witness Hartwick responded by addressing the Commission's concerns and otherwise providing additional support for cost recovery (6T 691-99). She first explained that the project's name was kept for consistency, but the investments in EV technology go beyond that ACM Xtreme Fast Charging component, which was completed in 2022, with the Company continuing to gather additional data on charging events (4T 691-92).

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 (4T 682-83).

The Omega pilot involves placing mobile storage equipment (the same equipment described above for the Mobile Battery Trailer pilot) at the Omega substation (4T 683-84).

The Fisher pilot includes targeted deployment of Demand Response (DR) and Energy Waste Reduction (EWR) to relieve a portion of the load concerns at the Fisher substation (4T 685-87).

The Port Austin pilot involves solar and storage to address concerns with the Port Austin substation being above its firm rating (4T 687-88).

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 (November 18, 2022 Order in Case No. U-20836, p 156). (4T 688-89).

The ACM demonstration was a collaboration among Delta, DTE Energy, and ACM.[72] The project included Company support for implementing the Delta Power Electronics DC Xtreme 400KW fast charger and solid-state transformer installation to gain understanding of the impacts of high-powered charging on power quality and operations (Hartwick, 4T 694-96; Exhibit A-12, Schedule B5.4.7). The characterizations of the technology demonstrated at ACM as "experimental" and "premature" are inaccurate. Ms. Hartwick explained in part:

> The ACM site charger, while not available commercially, has resulted in a commercial product that Delta is currently working to bring to market. The demonstration for the Department of Energy showed charging of 2023 model year vehicles, including a GMC EV Hummer at full power of 400 KW and operating at the maximum of 800V, double the standard charging voltage in older EVs. This showed that the system could readily perform DC fast charging of a Ford F-150 Lightning, Chevy Volt, and Cadillac Lyric at their maximum charge rate as well. All these vehicles were standard production and unmodified. This technology is fundamental to encouraging rapid electrification and improving the charging experience for EV owners by reducing the charging time for a full charge from multiple hours to just minutes. [Hartwick, 4T 696.]

Ms. Hartwick further explained that the ACM pilot provided benefits that can be applied elsewhere:

> By participating in Department of Energy projects that include equipment manufacturers and research institutions, DTEE is able to obtain valuable information on technologies such as fast charging as well as on solid-state transformer technology performance. DTEE also supported Delta in developing a product that would allow high power charging to be applied more cost effectively in the future by eliminating equipment and construction costs for unnecessary secondary voltage equipment and transformation. Additionally, DTEE evaluated the method needed for grid connection and operation at high powered charging sites that will not have on site trained electrical staff like an industrial facility might have. The demonstration also provided experience with solid state transformer technology where the EV charger direct current is directly coupled to the medium voltage primary system, allowing for higher charging rates and significant efficiency gains by eliminating traditional transformation and secondary voltage wiring. [Hartwick, 4T 697-98.]

[72] The ACM project successfully leveraged different resources to innovate and support electrification. Delta, the primary recipient of the grant, funded development of the solid-state transformer and extreme fast charging system, and provided the equipment to the project. The Company, as the host utility, provided engineering input into the project to reach a successful integration of the grid connection and engineering and operating support. AMC was the site host, providing a test track that was necessary to rapidly discharge vehicle batteries to perform testing (Hartwick, 4T 697).

Other EV charging investments also provide benefits to customers. As EV's become more prevalent in the Company's service territory, the learnings from these projects will support a more efficient incorporation into the grid, laying the groundwork for EV's to be a grid-benefitting resource. The additional investments provide three major benefits:

> Create a consistent and clear set of standards and requirements for the connection and operation of Vehicle to Home (V2H) and Vehicle to Grid (V2G) technologies, and to use these as the baseline for necessary changes in processes and organizations that directly interface with the customer that is requesting those capabilities to streamline that experience;
>
> Define and implement the appropriate communication, cybersecurity, and control architectures for managed charging to allow for greater adoption of EV charging and minimizing the impact of grid constraints; and
>
> Increase insight into the benefits of managed charging and the impact of EV charging on system loading and power quality, especially at high concentrations of charging to optimize circuit design and develop consistent methods for modeling the variability of managed charging and EV charging; this information will translate into projects that are better at integrating electrification. [Hartwick, 4T 698-99.]

The Company also proposes additional pilots, including Adaptive Networked Microgrids (ANMs).[73] The DOE selected DTE Electric for Infrastructure Investment and Jobs Act (IIJA) funding to expand on the Company's NWA work. The Company will use this funding to grow the deployments at the O'Shea solar park and Port Austin substation, and to incorporate ANMs to further increase customer benefits. These sites were selected because they have already-deployed assets that can be used in the networked microgrids, which will lower overall costs. The two locations (an urban area with a high energy justice score, and a rural area with longer circuits) will

[73] ANMs are two or more neighboring microgrids with controls and protection that enable them to merge based on several considerations including, but not limited to, the location of faults, load forecasts, weather forecasts, and DER status. These microgrids can dynamically change their boundaries through switching operations to isolate faults and improve reliability for customers (Hartwick, 4T 701).

also allow the ANM concept to be fully developed and tested for customer benefits in a range of settings (Hartwick, 4T 699-700, 702-703).

The Company is focused on microgrid development and deployment because they provide an opportunity to increase the benefits of the Company's NWA deployments and customers' DER installations. Deploying microgrids is also aligned with the DOE's vision, which includes microgrids as a building block for the future electrical system to support resilience, decarbonization, and affordability (Hartwick, 4T 700-701). Ms. Hartwick explained the customer benefits:

> Benefits to the Company's customers include (a) greater resilience to extreme weather conditions, (b) improved reliability for everyday operations, (c) enhanced security from an evolving number of cyber-physical threats, (d) superior flexibility to respond to the variability and uncertainty of conditions, and (e) increased sustainability through energy efficient and renewable resources. Additionally, the project will support the advancement of microgrids in general. Other technology, such as fault locating and state estimation will be developed from the project, that will benefit customers outside of the networked microgrid deployment. Overall, this will place Michigan as a leader in Adaptive Networked Microgrid technology. [Hartwick, 4T 702.]

There are seven areas of focus for the development and testing leading up to the installations at O'Shea and Port Austin: (1) Project and Technical Management, (2) Sensors and Data Analytics, (3) Cybersecurity, (4) Control and Protection, (5) Engineering Due Diligence, (6) Microgrid Deployment, and (7) Sharing Lessons Learned (Hartwick, 4T 701. See Exhibit A-12, Schedule 5.4.9 Revised, section 2(a) for details on these seven areas).

The project is expected to progress over four phases from 2024 to 2027, with the Engineering Phase primarily occurring in 2024, the Development Phase primarily occurring in 2025, the Deployment Phase primarily occurring in 2026, and the Assessment Phase primarily occurring in 2027. The estimated cost is approximately $46 million. This includes $23 million from

the DOE, and $1 million from the Company's partners.[74] That leaves approximately $22 million in funding from DTE Electric (Hartwick, 4T 703-704; Exhibit A-12, Schedule B5.4 Revised, page 17, lines 26-27).

Staff "recommends a full disallowance of all requested capital expenditures for the ANM pilot . . . [and] the corresponding partner contributions and grant funding which offset a portion of these costs be credited, to ensure this pilot has no impact on the revenue requirement . . . While Staff is generally supportive of this pilot and the value that it could provide the Company through the development and operation of adaptive microgrids, Staff does not find it appropriate to include this pilot in rates when the status of the Company's grant application is uncertain, particularly given the Company's indication it would likely not proceed with this project if this grant funding is not approved" (DeCooman, 6T 5065).

The Company appreciates Staff's general support and will continue working diligently with the DOE to reach a funding agreement. Since the project's as-filed in-service date is 2027, the disallowance does not impact the revenue requirement (Hartwick, 4T 856). The Company is also generally pursuing grant opportunities to provide funding for investments in distribution infrastructure (Kryscynski, 3T 74-69).

DAAO witness Makhijani proposed that "an underground geothermal network be evaluated as a pilot project for at least one resilience microgrid in Highland Park" (6T 4629), and GLREA witness Richter proposed that the Commission "direct the Company, in its next rate case or demand

[74] The Company formed the Adaptive Networked Microgrid Partnership (ANMP) for this work. The Company's partners include Open Systems International (OSI), Open Energy Solutions (OES), Electric Power Research Institute (EPRI), and the University of Michigan-Dearborn. Lawrence Livermore National Laboratory (LLNL) and National Renewable Energy Laboratory (NREL) are advisors for the project (Hartwick, 4T 702. Exhibit A-12, Schedule B5.4.9 describe each partner's role).

response case, to propose a pilot of geo-targeted incentives for customer-owned distributed energy systems (including batteries)." (6T 4849).

The Company disagrees because it is committed to completing the ongoing NWA pilots and using the results to inform how to scale the piloted technologies. Although the Company does not have current plans to expand the set of NWA pilots, it will continue to evaluate promising new technologies, and use the recently developed expedited pilot process (February 23, 2023 Order in Case No. U-20898) for consideration of any future potential pilots (Kryscynski, 3T 467-68).

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 provided updates on approved pilots, and additional information supporting cost recovery for the ACM demonstration project in response to criticisms in Case No. U-21297. The Company also explained and supported an ANM project to build on the work at O'Shea and Port Austin, and provide additional benefits to customers. The pilots are reasonable, prudent, and well-supported. Therefore, the Company's requested cost recovery should be approved.

5. Grid Edge Insights and New Technology

This collection of projects (summarized in Table 4 at Hartwick, 4T 706) is designed to consolidate the learnings from the NWA projects into a consistent platform, and to unlock the capabilities of new equipment that is being used to run the grid safer, more reliably and efficiently, and ultimately increase the amount of DER that the grid can accommodate (Hartwick, 4T 704-708).

The categorization of these projects has changed. Investments in 2022 ($1.64 million) and 2023 ($2.75 million) was under the "Interconnection Process Enablement" OT program,[75] and was mostly for the expansion of the small solar and storage testbed site to incorporate three-phase 480V

[75] For 2024, this is described under Operational Technology Distribution Planning (Hartwick, 4T 709).

and medium voltage testing capability and gateway testing hardware, producing efficiencies that benefitted customers (Hartwick, 4T 709-11).

Beginning in 2024, all of the control and hardware investment will be included in the Grid Edge Enablement and New Technology category. There is no duplication of work. There is just a change in classification to more closely align the projects with their focuses going forward (Hartwick, 4T 710). Ms. Hartwick also discussed the Company's planned work for 2024 and 2025, and resulting customer benefits (4T 711-12).

6. Distribution Line Sensors

The Distribution Line Sensors[76] program includes overhead system sensors used to monitor power quality and fault data needed for real-time load transfer analysis, fault locating, and system status, as well as Underground Residential Distribution (URD) sensors to quickly direct field crews to underground fault sections to improve isolation and restoration times. In 2023, the Company installed 398 underground (UG) line sensors, and 100 overhead sensors. The Company also purchased 300 pole sensors and 1,000 overhead line sensors for future installation. In 2024, the Company will install 300 pole sensors and 500 overhead line sensors. In 2025, the Company will install the remaining overhead sensors, and 1,300 underground sensors (Hartwick, 4T 712-14).

7. Grid Management

Grid management investments enable the Company to monitor, control, and optimize the operation of Grid Automation investments. Key drivers for the investments are (1) cybersecurity, (2) electrification, (3) demand response, (4) renewable integration, and (5) reliability and resiliency.

[76] Distribution line sensors are devices that are used to monitor the real-time status of the distribution grid, and provide critical information to field personnel and system control room operators to help them better monitor and manage the grid. They benefit customers by supporting faster outage restoration (Hartwick, 4T 712-13).

Table 5 at Hartwick, 4T 722 specifies where details for the projects and programs are located in Exhibit A-12, Schedule B5.4. pp 17-18, and Exhibit A-23, Schedule M7 (Hartwick, 4T 720-22). Ms. Hartwick also provided details regarding the projects and programs in her testimony, as indicated below.

System Operating Center (SOC) Modernization. Ms. Hartwick provided an update on this project, which replaced the Company's outdated primary SOC and backup SOC by constructing the Electric System Operations Center (ESOC, which was essentially complete and fully occupied in February 2022) and Alternate System Operations Center (ASOC), which has been constructed and is expected to achieve full NERC certification in the third quarter of 2024 (4T 722-26).

Advanced Distribution Management System (ADMS); Distribution Management System (DMS)/ Outage Management System (OMS). ADMS is an advanced operating technology platform that is essential to DTE Electric's grid modernization efforts to improve system reliability and operational efficiency. The Commission previously approved the Company's requested DMS/OMS expenditures, finding that "[o]utage restoration response is a critical area . . . [and] the company took reasonable steps to address the problems with the DMS/OMS in light of the available options" (December 1, 2023 Order in Case No. U-21297, p 114). DMS and OMS went live in February 2023. There were immediate benefits, and the Company will continue to build on the DMS foundation by implementing additional modules and enhancements to produce additional benefits (Hartwick, 4T 726-30). The investments to enable remaining applications over the next 3-5 years is found in the ADMS Enhancements and Fault Location, Isolation, and Service Restoration (FLISR) Implementation line items in Exhibit A-12, Schedule B5.4, p 18, lines 32 and 35. See also Hartwick, 4T 738-41 (ADMS Enhancements), and 4T 755-61 (FLISR Implementation).

Other Modernize Grid Management. These investments encompass a diverse set of projects designed to enhance the Company's operational capabilities, particularly during outage

events that impact a large number of customers. Key investments are (1) OSI Licensing, (2) Qlik 3-year license purchase, (3) Current Transformer/Voltage Transformer (CT/VT) High Voltage Test Console, (4) Purchase of backhaul-capable field area routers, (5) EFC Communications – Outage Status (EFC), (6) Pre-Storm ADMS Enhancements, and (7) Post-Storm ADMS Enhancements. The final three projects are crucial to supporting storm restoration and communication. The ADMS enhancements were initiated in 2023 with new ADMS-enabled technology (launched February 6, 2023) and in response to the subsequent severe storms, and will continue in 2024 and beyond (Hartwick, 4T 729-31). Ms. Hartwick also discussed the drivers and benefits of investments in this category totaling, with EFC - Core System investments explained and supported by Mr. Hatsios (Hatsios, 6T 2254-64), $7,800,000 in 2022, $26,400,000 in 2023, $2,200,000 in 2024, and $2,500,000 in 2025 (Hartwick, 4T 732-38; Exhibit A-12, Schedule B5.4, p 18, line 40).

ADMS Enhancements. As indicated above, all ADMS applications were deployed in 2023, and the Company will continue to build on this foundation by implementing additional modules and enhancements. ADMS Enhancements are necessary to realize the full benefits of ADMS, and keep up with evolving needs and challenges of the modern electrical grid, as well as regulatory requirements and enhancements to strengthen cybersecurity measures to protect against potential vulnerabilities. The scope of work for 2024 and 2025 is focused on the eMap application, Switch Order Management (SOM) phase 2, SOM phase 3, and added AMI functionality (Hartwick, 4T 738-41; Exhibit A-12, Schedule B5.4, p 18, line 32).

Operational Technology (OT) and Error Free Communication (EFC). These related investments are divided into two categories. OT investments support the operational activities required to ensure customer commitments (such as restoration times) are met. EFC investments focus on communicating with customers about those operational efforts, and focus on resolving communication challenges that lead to customer dissatisfaction. The investments, including the

EFC - Core System portion, which is supported by Mr. Hatsios (Hatsios, 6T 2254-64), totals $5,496,000 in 2022, $136,000 in 2023, $5,600,000 in 2024, and $1,400,000 in 2025 (Hartwick, 4T 741-42; Exhibit A-12; Schedule B5.4, p 18, line 33).

The OT work completed in 2022 and 2023 focused on the following projects: (1) Type 2 Customer Communication & Processes, (2) Outage App Updates and Security Upgrades, and (3) Pentos PPE Dashboard (Hartwick, 4T 742-44). The following OT projects are planned for 2024 and 2025: (1) Data Analytics and Data Engineering for Outage Restoration, (2) Damage Assessment and Inspections Image Analytics, (3) DO RCO Enhancement GPS Productivity, and (4) System Outage Screen (SOS) Hardening (Hartwick, 4T 744-46).

Customer Power Status Visibility (CPSV). This is the first of a series of planned projects to transform the Company's Advanced Metering Infrastructure (AMI) asset from a purely billing-based design to a system capable of maintaining billing excellence while adding changes aimed at fully supporting the outage detection and response use case. The project will enhance the existing AMI network by adding additional network communication devices to locations that lack the capacity to transport the volume of data needed from meters to the OMS system (Hartwick, 4T 746-50). The project will provide the following benefits by the end of the Phase 1 period in December 2024: (1) maximize the number of customers that are included in outage communications, (2) maximize the accuracy of the first and all subsequent estimates provided to customers, (3) maximize the timeliness of delivering a first estimate to customers, (4) maximize the ability to predict customer outages where no direct information is available, and (5) minimize the number of OK on Arrivals (Hartwick, 4T 750-52).

Advanced Metering Infrastructure (AMI) Meter Communications Upgrade. This project reflects the yearly capital investment needed to replace devices (primarily field area routers)

that reach the end of their useful deployed lifecycle or are destroyed in the field by weather events or other incidental damage (Hartwick, 4T 752-53).[77]

Microwave End of Life. The Company owns and operates its own microwave communications installations. This investment is necessary to maintain a reliable network, and includes replacement of microwave paths, enhancements to stabilize the microwave ring, and support changes mandated by the FCC in deregulation of the 6 gigahertz (GHz) frequency (Hartwick, 4T 753-55).

Fault Location, Isolation, and Service Restoration (FLISR). This is a sophisticated software application that integrates with other ADMS platform applications, such as Distribution Power Flow (DPF), to enable efficient fault response and power restoration. The investment will help the Company improve storm restoration via reduced outage duration, as well as enable the Company to continue realizing the full benefits of ADMS and automation. The two main benefit drivers are fault location identification and restoration switching analysis, but the resulting reduced stress on equipment is also expected to prolong its useful life (Hartwick, 4T 755- 61).

Distributed Energy Resources Management System (DERMS). The electric grid of the future will need to incorporate new technologies, including Distributed Energy Resources (DERs) such as solar and battery storage. A DERMS acts as a switchboard for DER-related protocols and information to simplify the management of these systems and feed information into other systems for planning, operations, and customer engagement (Hartwick, 4T 761-63).

The Commission previously recognized that DERMS can be a valuable tool and that the Company's overall strategy was appropriate, but found that this long-term project lacked sufficient support, stating:

[77] This is included as one of the Company's strategic projects in this case, but will be covered as routine replacement capital in future cases (Hartwick, 4T 752).

> DTE Electric failed to offer sufficient detail to allow for a finding of reasonableness and necessity. For an investment of $7.2 million the Commission expects a more robust evidentiary presentation. DERMS can be a valuable tool and the Commission appreciates the company's overall strategy with regard to linking this information to the DGP, but the record (which includes the DGP references) does not contain sufficient justification for the investment. [December 1, 2023 Order in Case No. U-21297, p 132.]

Accordingly, Company witness Hartwick presented a detailed discussion explaining (in addition to the discussion above), that the Company will begin investment in DERMS in 2025, which will allow an evaluation of MISO FERC 2222 requirements that will be available by Q3 2024. The initial investment will be in the program and configuration database to centralize program management, program constraints, and the tools to assign DER to system model nodes. The Company's approach provides for capacity to expand to support higher DER adoption rates, while recognizing that it would not be practical or cost effective to implement a system that can initially support a high DER level that might not materialize. Doing nothing would not be reasonable or prudent, however, because not having a system to manage DER in a comprehensive way would lead to potential non-compliance, inefficiencies, and degraded customer experience (Hartwick, 4T 763-65).

Substation Cybersecurity Program. This program develops and deploys cybersecurity tools supporting the increasing use of distribution automation devices across DTE Electric substations and circuits (Hartwick, 4T 766-67).

Automation Configuration Database. This is an investment in tools for improved tracking of intelligent electronic devices, specifically distribution relay and network communications equipment (Hartwick, 4T 767-68).

8. Distribution Planning

These investments are in the tools, processes, software applications and data models supporting the near and long-term planning of the distribution system. Table 9 (at Hartwick, 4T 769) identifies where details of these projects are included in Exhibit A-12, Schedule B5.4, pp 17-18, and Exhibit A-23, Schedule M7 (Hartwick, 4T 768-70). Ms. Hartwick also explained and supported the investments as indicated below.

Network Management System (NMS). The Company implemented NNS as part of the ADMS project in 2020, and the Commission previously approved the Company's requested recovery for investments in additional technology (December 1, 2023 Order in Case No. U-21297, p 116). Ms. Hartwick further explained NMS' accomplishments, and the need for additional investments to update and change systems that mange the electric grid as the grid continues to change (4T 770-76).

Load Forecasting & Analytics. The Commission previously declined to approve the investment in this category for lack of sufficient support, and further "note[d] that the proposed expenditure appears to be primarily for labor, which indicates that this may belong in O&M rather than Capital Expenditures" (December 1, 2023 Order in Case No. U-21297, p 135).

Accordingly, Ms. Hartwick explained that this program invests in planning tool capabilities that are focused on (1) the essential industry standard distribution planning tool CYME, which models distribution circuits and calculates load flow, and (2) the load analysis tool Power Runner, which combines SCADA, AMI and forecasted load data to generate load allocation scenarios to CYME. She also supported the investments that were made in 2022 and 2023, and that are planned for 2024 and 2025, including their benefits to customers (Hartwick, 4T 776-78).

Interconnection Process Enablement. These investments focus on the software and interfaces for interconnection processing that includes both the interconnection portal and the

interconnection database, PowerClerk. Ms. Hartwick explained and supported the investments that were made in 2022 and 2023, and that are planned for 2024 and 2025, including their benefits to customers (4T 779-80).

Hosting Capacity Enablement. These investments include improvements to the online publicly available map system that displays hosting capacity, and the capabilities to compute hosting capacity and process the data for it to be available publicly. Ms. Hartwick explained and supported the investments that were made in 2022 and 2023, and that are planned for 2024 and 2025, including their benefits to customers (Hartwick, 4T 780-81).

Power Quality Analysis Program. This program invests in software to centralize, collect, correlate, and visualize power quality data. It is a new category beginning with 2024 investments to centralize power quality data into a single data set. Analysis tools and machine learning capabilities will be added in 2025 (Hartwick, 4T 781-82).

Substation Design Tool Upgrades. These investments consist of design and structural calculation tools that are used by engineers, planners, and designers to implement standards and calculate physical analysis into designs prior to construction. Ms. Hartwick explained and supported the investments that were made in 2022 and 2023, and that are planned for 2024 and 2025, along with their benefits to customers (4T 782-83).

Distribution Planning. This is a collection of investments from the other sub-programs in the Distribution Planning OT category (Exhibit A-12, Schedule B5.4, p 18, line 46). Ms. Hartwick explained and supported the investments that were made in 2022 and 2023, and that are planned for 2024 and 2025, including their benefits to customers (4T 783-85).

9. Work Management and Scheduling

Work Management is a systematic approach to track and measure work, as well as streamline business processes and routine tasks. Investments are for essential work-management tools and technologies that are used to coordinate work on the distribution system (Hartwick, 4T 785). Table 10 at Hartwick, 4T 786 specifies where details for the projects and programs are located in Exhibit A-12, Schedule B5.4. pp 17-18, and Exhibit A-23, Schedule M7 (Hartwick, 4T 786). Ms. Hartwick also provided details regarding the projects and programs in her testimony, as indicated below.

Enhance Maximo Capabilities and Processes. Ms. Hartwick outlined the key drivers and benefits of this project, which is aimed at improving and expanding the functionality of Maximo (the Company's Work and Asset Management system), and optimizing its associated processes. (4T 786-87).

Primary Service Orders (PSO) Replatform. Ms. Hartwick explained and supported the scope, key drivers, and benefits of this three-year project, beginning in 2024, to combine and upgrade the web-enabled tracking system that the Primary Services Group uses to assist many of the Company's largest commercial and industrial customers (4T 787-89).

External Crew Efficiency. These investments target the efficient and cost-effective use of external contract crews to augment Company crews, which is a key component to improving the speed and efficiency of storm restoration. The primary investment is the Utility Restoration Management Application (URMA), which is a multi-year project that began in June 2023 to manage crew rosters for external contract crews, track current job status and work completed in the field, and enable visibility into contractor productivity and payment. Ms. Hartwick explained and supported the key drivers, scope, planned investments, and benefits including productivity improvements and reduced average duration for outages (4T 789-92).

Work Management and Scheduling Upgrades. Ms. Hartwick explained and supported investments that were made in 2022 and 2023, including key drivers and benefits of the Type 2 Customer Communication & Process Efficiency Closed Loop project, Contract Agreement System (CAP) Replacement project, Crew Management Enhancement project, PMO P6 Primavera Refresh project, Multi-year Renewal license purchase for ARCOS, and Field Operations Tools Automation (4T 792-800), and planned investments for 2024 and 2025 in Circuit Ownership application, Wiredown Associated Call Enhancement, and Moving Mobile Timesheet (MTS) Data to Cloud (4T 800-802).

10. Asset Management

These investments involve utilizing technology to support effective asset management, including projects that support managing physical assets as well as electronic asset data management (Hartwick, 4T 802). Table 11 (at Hartwick, 4T 803) identifies where details of these projects are included in Exhibit A-12, Schedule B5.4, p 17, and Exhibit A-23, Schedule M7 (Hartwick, 4T 802-803). Ms. Hartwick also explained and supported the investments as indicated below.

Systematic Tracking of Rotatable Assets. Ms. Hartwick outlined the key drivers and benefits of this new investment in 2025, which will develop and implement a digital tracking repository for items like personal protective equipment that have expiration dates and must be managed through their deployed life cycles, resulting in improved safety, efficiency, and accountability (4T 803-804).

Asset Management Upgrades. Ms. Hartwick outlined the key drivers and benefits of the Brigade 360 Cameras project, which included installing 360-degree cameras on DO vehicles to reduce motor vehicle accidents and improve crew and facility safety (4T 804-805).

11. Mobile Technology

Mobile Technology investments focus on creating seamless transitions between on-line and off-line operations, and provide integrated communication, including workflows, between the control room, field leaders, field crews, and supporting organizations (Hartwick, 4T 805). Table 12 (at Hartwick, 4T 806) identifies where details of these projects are included in Exhibit A-12, Schedule B5.4, p 18, and Exhibit A-23, Schedule M7 (Hartwick, 4T 806). Ms. Hartwick also explained and supported the investments as indicated below.

Mobile Tools Expansion. These investments relate to tools and applications utilized by field resources. The primary investment is the Every Day Daily Plan (EDDP), which is a web application designed to serve as a consistent "all-weather" tool for daily planning processes in both storm and non-storm scenarios. It arose from lessons learned from the 2023 catastrophic ice storm and the capabilities of new systems and streamlines operations producing benefits including increased productivity and reduced restoration time (Hartwick, 4T 807-808).

Maintain Compliance. The Company is subject to multiple regulatory authorities and must maintain compliance with MPSC and other industry regulations and orders. The Company needs to have access to, as well as safeguard, accurate and complete operational data (Hartwick, 4T 808-10).

Enhance and Expand Cybersecurity. The Company's investments in grid automation must be protected from cyber-attacks. This program assesses cybersecurity needs and informs the selection of tools and techniques to combat the threats, which is critical for operations and safety (Hartwick, 4T 810-11).

Mobile Equipment Replacement. The thousands of mobile devices that are deployed to the Company's front-line workers and their leaders have planned useful deployed lifecycles of 6

years, so every year about 1/6 of the devices need to be replaced, providing workers with operational and secure devices to safely and effectively do their jobs (Hartwick, 4T 811).

Mobile Technology. In previous cases, the Company presented this category at a high level, as the sum of several projects. Based on feedback from the Commission and intervenor discovery, however, the Company itemized key investments in this case. Ms. Hartwick explained and supported the scope, key drivers, and benefits of Outage Status App Changes for Damage Assessment (4T 812-13), Tree Trim's Vegetation Software Replacement Pilot Project (4T 814-15), Service Center Wi-Fi Upgrades (4T 815-16), Lemur Pro Multiyear License Purchase (4T 817-18), and Field Service Edge (FSE) Overhead (OH)/Underground (UG) Enhancements (4T 817-19).

5. Community Lighting

DTE Electric's Community Lighting capital expenditures were $17.8 million in 2022, and are expected to be $16.7 million for 2023, $17.3 million for 2024, and $17.3 million for 2025 (Bellini, 6T 3119; Exhibit A-12, Schedule B5.5).

In Case No. U-21297, MI-MAUI witness Bunch proposed a $5.8 million disallowance, claiming that the Company spent too much on replacement LED luminaires for high-intensity discharge (HID) conversions. This claim was based on a cross-over chart published by the Company's primary luminaire vendor, Leotek (reflected for example in witness Bunch's workpaper, which is included here as Exhibit A-25, Schedule A4). The Commission found that the Company complied with the U-20836 Order,[78] but that the evidence did not support the Company's position on selecting replacement luminaires for pre-existing municipal lighting systems, and

[78] The Commission previously 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).

therefore approved MI-MAUI's recommended disallowance (December 1, 2023 Order in Case No. U-21297, p 139).

The Company requests that the Commission revisit its disallowance based on new developments, particularly Leotek no longer supporting and now disavowing its crossover chart (Bellini, 6T 3121-22). MI-MAUI's proposed disallowance, adopted by the Commission in Case No. U-21297 used the Leotek cross-over chart. Now removed, there is no longer a basis for this calculation or standard for replacement luminaires to be installed by the Company. The Company also sought the independent review of two lighting industry experts: (1) Dr. Ronald Gibbons, PH.D, FIES (Director of the Center for Infrastructure Based Safety Systems (CIBSS) at Virginia Tech Transportation Institute (VTTI)), and (2) Donald McLean PLEng (Founder and Senior Partner, DMD Consulting Engineers, Ltd). These experts supported the Company's LED selection methodologies, and particularly the Company's use of 58W and 136W LED selections when converting 100W HPS and 250W HPS fixtures (the most commonly converted municipal fixtures), respectively (Bellini, 6T 3123, 3147, 3172-73).

Company witness Bellini further explained that the Company uses several criteria in evaluating lighting options, but roadway illuminance and luminance are weighted more heavily than other criteria such as glare, light trespass, etc. (Bellini, 6T 3124-25). He also recounted the key points from the conclusions in the experts' reports (Bellini, 6T 3123-24; Exhibit A-25, Schedule O5, p 15, and Schedule O9, p 11) and provided additional details regarding the expert reviews and conclusions reached by the lighting industry experts (6T 3125-30).

The Company made four recommendations based on this new evidence, and maintains the following three (the fourth is modified as discussed below):

First, based on the experts' independent analyses and conclusions supporting the Company's LED selections for conversions, it would be prudent to continue using 58W and 136W

Leotek LEDs when converting 100W and 250W HPS luminaires, rather than being limited to choices based on Leotek's crossover chart, which Leotek no longer supports.

Second, in response to the suggestion that "DTE has not established that it has any meaningful discussion with customers currently regarding the choice of lighting" (U-21297 PFD, p 340), the Company proposes to memorialize its LED recommendations (noted immediately above) to the customer in their contract prior to signing, and by explicitly informing the customer in the contract and during discussions that the customer has a choice to select another LED at their discretion and confirmed in the municipal conversion agreement.

Third, revisit the $5.8 million disallowance ordered in Case No. U-21297, and allow that recovery based on the new evidence outlined above and further detailed on the record (Bellini, 6T 3130-31).

MI-MAUI witness Bunch disagreed with this third proposal, contending that the "Company has failed to meet the clear standard that the Commission set in Case No. U-21297, which is to demonstrate that its costs are consistent with reasonable efforts to comply with roadway lighting standards" (Bunch, 6T 4328), and recommending a cumulative disallowance pertaining to HID-LED conversions of either $7,705,567 (including the $5.8 million written down based on the Order in Case No. U-21297) or $5,833,539 if the Company were to adopt Consumers luminaire selections (Bunch, 6T 4347).

The Company maintains its position for three key reasons. First, as indicated above, witness Bunch's position lacks merit because his only basis for asserting that the Company selected overly-bright LEDs and calculating the disallowance that the Commission ordered in Case No. U-21297 was the (Leotek) LED crossover chart mentioned above, that has since been disavowed by the vendor and is no longer supported and available. Witness Bunch acknowledged that "Leotek has removed the chart and now offers no conversion advice" (Bunch, 6T 4334). Second, the Company

engaged two lighting industry experts to analyze the Company's LED selection methodology. Both lighting industry experts independently concluded that the Company's methodology for selecting LEDs was reasonable and appropriate. Third, after an exhaustive study performed by MI-MAUI member Ann Arbor in selecting replacement luminaires for their upcoming municipal conversion project, Ann Arbor selected as their primary luminaire, a 58W fixture. (Exhibit A-54). This fixture is much closer to those that the Company stocks, and much higher in wattage than both those shown on Leotek's cross-over chart and what Consumers currently installs. Therefore, the Commission should reject MI-MAUI's disallowance proposals, and instead reverse the Company's disallowance from Case No. U-21297 and affirm its LED selection methodology or alternatively, order a technical workshop or joint collaborative as further discussed below in the Company's fourth original recommendation. (Bellini, 6T 3147, 3171-73, 3175-76).

MI-MAUI witness Bunch also attempted to support his proposed disallowance by asserting that "DTE stocks luminaires with CCT of 4,000k. The ANSI/IES RP-8 standard recommends luminaires around 3,000k on highways to improve driver visibility and reduce glare" (Bunch, 6T 4339). There is no such guidance in this standard. To the contrary, the Federal Highway Administration handbook states "at higher speeds, 4000K LED lighting might be beneficial for increasing driver visibility (Engineering & Medicine, 2020). Similarly, other research has shown that the use of 4000K light sources generally improves object detection distance" (Bellini, 6T 3173; Exhibit A-40, Schedule EE6).

Witness Bunch also claimed that lighting industry expert McLean's analysis showed that the incumbent 100W and 250W HPS fixtures "overlit" or "drastically overlit" roadways relative to current standards (Bunch, 6T 4336-37). These claims are inaccurate. Both lighting industry experts evaluated the Company's replacement LEDs as an equivalent to the original HPS fixture. Streetlight systems are designed to overperform when initially deployed because the lumen output of roadway

luminaires diminishes over time. Witness Bunch appeared to acknowledge this in discussing Grand Rapids' installation of dimmers on its LEDs, so "as the luminaires light output slowly decreases over time, Grand Rapids can adjust to yield constant illumination by giving the luminaire more electricity" (Bunch, 6T 4344). Thus, as a safety factor, there must be a light loss factor included in the initial design. This measure of over-light ensures adequate lumen output throughout the fixture's useful life. The Company did not include a light loss factor in the data that it provided to Mr. McLean. When a light loss factor is included, the Company's luminance results are in line with published luminance guidance. Using the 100W analysis as an example, when adjusting for a light loss factor of 0.701, the 100W HPS and the Company's recommended 58W LED replacement show a positive result of 3% and 29% respectively (Exhibit A-40, Schedule EE8 Revised), both within the limits set by the Federal Highway Administration. Therefore, neither the 100 W HPS nor the Company's equivalent 58W LED were "overlit," but instead both provide adequate lighting (Bellini, 6T 3174-75).

The Company's fourth original recommendation was that, if the Commission deems it necessary, the Company would be amenable to a Staff-facilitated technical workshop including the Company, Leotek's engineering team, outside consultants, and MI-MAUI, to evaluate appropriate HID to LED equivalent conversions (Bellini, 6T 3131). The Company revises its recommendation due to MI-MAUI witness Bunch's apparent shift in now recommending an alternative disallowance based on "Consumers Energy's LED equivalencies" (Bunch, 6T 4347). It would be reasonable for Staff to conduct a technical workshop or joint collaborative that includes Consumers in which to compare and contrast the LED selection methodologies of the Company and Consumers. Such a forum is appropriate due to the voluminous and technical information involved, and the purpose should be to establish an agreed-upon standard when selecting common LED fixtures best suited for municipal streetlighting customers (Bellini, 6T 3175-76).

On a somewhat related matter, Ann Arbor witness Naheedy indicated that for the City's HID LED conversion project, the City "wanted all sample streetlights to meet lighting standard IES RP-8, have a correlated color temperature no higher than 3000K . . . None were 'standard offerings' from DTE because all of them had a color temperature lower than what DTE normally offers" (Naheedy, 6T 4227). Ann Arbor apparently considers that having to stock a 58W LED with a lower color temperature as a "special-order material ('SOM') fixture" is unreasonable (Naheedy, 6T 4229).

The Company disagrees because Ann Arbor's sampled LEDs would not have met IES RP-8 standards. ANSI/IES RP-8-22, section 10.3.4 ("Spectral Considerations") notes a "practical difference for 4000K, which had greater detection distances especially for pedestrians, than any of the other light sources." Therefore, the Company's standard 58W LED fixture with a 4000K CCT aligns with ANSI/IES, while all of Ann Arbor's sampled lights (and the one it chose) are not in alignment (Bellini, 6T 3148, 3180).

Witness Naheedy suggested that Ann Arbor was financially disadvantaged in converting to LED streetlights because if Ann Arbor had waited until each of its remaining HID fixtures failed, then it eventually would have all LED streetlights with no requirement to pay CIAC. (Naheedy, 6T 4230). This is incorrect because, as indicated above, Ann Arbor chose to proceed with a 58W LED fixture with a special, lower color temperature, whereas the Company's standard stock LED replacement is a 58W 4000K CCT fixture. Also, as discussed below in section X.G (Streetlighting Rate Design) with respect to MI-MAUI, the Company's reactive replacement of failed, obsolete fixtures with LED fixtures is a well-established practice that differs from a customer's choice to replace its HIDs with LEDs (Bellini, 6T 3149, 3180-81).

MI-MAUI proposed that the Commission disallow recovery for the underground cable replacement program (Bunch, 6T 4318). The Company disagrees. MI-MAUI's proposal is based in

part on the incorrect assertion that the "Company has not provided reliability or cost data to justify this program" (Bunch, 6T 4316). To the contrary, all of the underground replacement projects completed since program inception were data-driven[79] and resulted in avoiding future outage events, as reflected for example by a project located in the City of Riverview, which is representative of the types of cable replacement candidates the Company targets for long-term repairs. MI-MAUI's proposed disallowance is also counterproductive because it would result in the Company having to engage in expensive and reactive repairs, addressing only symptomatic issues instead of the root cause (the failed underground cable itself), and unnecessarily increasing outage counts and customer discontent (Bellini, 6T 3146, 3162-65; Exhibit A-40, Schedule EE3).

MI-MAUI's proposed disallowance was also based on the "general proposition [that] the Commission should not authorize distribution system investments that have not been incorporated as part of DTE's DGP" (Bunch, 4T 4316). This proposition neglects that the DGP's focus is specific to distribution investments and does not extend to streetlighting. Community Lighting's assets, system of operations, and investments are distinctly different than the Company's distribution system. Also, Community Lighting from a cost-of-service / rate design perspective, maintains its own rate base, a separate set of projected capital and O&M expenditures, etc. Therefore, Community Lighting investments are appropriately excluded from the DGP (Bellini, 6T 3146, 3164-65).

6. Demand Response (DR) Programs and DTE Insight

DTE Electric spent $8.0 million in capital expenditures for its Demand Response (DR) portfolio in 2022, including the Interruptible Space Conditioning (CoolCurrents), Programmable

[79] The criteria to prioritize and replace failed/end-of-life underground cable are (1) age of cable; (2) pedestrian conflict (level of pedestrian traffic): (3) recurring outages; (4) number of lights out; and (5) type of road (Exhibit MAU-23). Cost data is reflected in Exhibit A-12, Schedule B5.5, line 5 (Bellini, 6T 3162).

Controllable Thermostats (PCT or SmartCurrents), and Other DR Programs and Pilots. DTE Electric also plans to invest $17.4 million for that portfolio for the bridge period of January 2023 through December 2024, and $4.4 million in the projected test year (Farrell, 6T 2672, 2700; Exhibit A-12, Schedule B5.6, page 1, columns (b), (e) and (f)).[80]

In addition, DTE Insight is a stand-alone program developed around a mobile application that aims to drive customer behavior with the goal of reducing both overall energy (gas and electricity) consumption, as well as specific electricity demand during peak hours. Total DR and DTE Insight capital spending was $9.4 million in 2022 and is planned to be $18.8 million in the 24-month bridge period ending December 31, 2024, with spending of $6.0 million in the projected test year (Farrell, 6T 2704-2705; Exhibit A-12, Schedule B5.6, page 1, line 6, columns (b), (e), and (f)).

Company witness Farrell described the overall purpose, importance, and regulatory framework of the Company's DR programs and pilots, and provided an overview of DTE Electric's DR portfolio (6T 2662-72).

The Interruptible Space Conditioning program (CoolCurrents) was first approved in Case No. U-17767. It is a dispatchable DR program in which a Direct Load Control Device (LCD) is installed on a customer's air conditioning unit or central heat pump in exchange for a discounted energy charge on the associated usage under the Tariff D1.1 Interruptible Space Conditioning Service Rate. Beginning in 2015, the Company has successfully replaced approximately 170,000 legacy Radio Control Units (RCUs) with a two-way communicating 24v LCD. Cost recovery for the ongoing program has been consistently approved. *See* December 1, 2023 Order in Case No. U-21297, p 140. Approximately 90,000 CoolCurrents customers still have legacy RCUs primarily due

[80] A breakdown of the capital expenditures is shown on Exhibit A-12, Schedule B5.6, page 2. The associated O&M expenses are shown on Exhibit A-13, Schedule C-5.9, line 9 (Farrell, 6T 2689).

to not having proper wiring in place to power the 24v LCD (like the legacy RCUs, the replacement LCD is powered by a 24v line that runs from the customer's furnace). To address this issue, in 2023, the Company received nearly 5,000 alternative 240v LCDs that are targeted to be installed in 2024. The alternative 240v LCD connects directly to, and obtains power from, the customer's HVAC unit, making the 24v line unnecessary. The Company has also had discussions with Consumers, which uses a similar 240v LCD, regarding how the alternative LCD is installed and operates. The capital investment of $2.2 million in the bridge period and $0.5 million in the projected test year will be used to order and install alternative LCDs, as well as support continued investigations into offline services, install new or replacement LCDs, and program operation costs (Farrell, 6T 2666, 2672-77; Exhibit A-12, Schedule B5.6, page 1, line 1, columns (e) and (f)).

The PCT program (SmartCurrents) is an offering where the customer receives a Wi-Fi enabled PCT and allows the Company to adjust the thermostat during SmartCurrents events. This is another ongoing program. *See* December 1, 2023 Order in Case No. U-21297, p 140. In August 2023, SmartCurrents was relaunched with changes including separation from the Dynamic Peak Pricing (DPP) tariff (D1.8 rate), so customers can take service under any residential electric base rate while participating in the program. Other changes included upgrading the thermostat to an ecobee Premium Thermostat, providing an annual participation incentive to increase retention, and revising the DR event parameters to increase the flexibility and availability of SmartCurrents as a MISO Load Modifying Resource (LMR). Since relaunch, the program has enrolled a net addition of 7,820 customers as of 2023, which was 29% of all program enrollees currently active as of that date. The Company also made changes to reduce program costs, for example the Company added a new installation scheduler tool that provides customers with the ability to schedule their appointments without contacting the call center. The Company projects to grow the cumulative number of enrolled thermostats from approximately 27,000 as of December 31, 2023, to 35,000 at

the end of 2024, and 40,000 at the end of 2025. The Company forecasts $8.3 million of capital expenditures in the 24-month bridge period ending December 31, 2024, and $2.5 million in the projected test year (Farrell, 6T 2666, 2677-81; Exhibit A-12, Schedule B5.6, page 1, line 2, columns (e) and (f)). (f)).

Company witness Farrell further explained that although the SmartCurrents program has generally had regulatory support, it was agreed in the Company's 2021 DR reconciliation settlement (Case No. U-21242) to remove $1,672,895 in capital costs (the difference between actual spending in 2021 and the $3 million preapproved in Case No. U-20471 (the Company' 2019 IRP case), plus 10%. The Company now seeks to recover this amount, which would increase the projected test year rate base by $914,448 (Farrell, 6T 2681-82, 2720).[81]

Staff maintained its position of no additional recovery (no disallowance in this case). (Doherty, 6T 5075-76). The Company maintains that the $914,448 of disallowed capital was reasonable and prudent, so it should be recovered. The over-spend was primarily attributable to creating a new webpage that enhanced and streamlined the customer journey. At the time of the 2021 DR reconciliation, the Company could not correlate increased enrollments and event participation to the new webpage. However, metrics are now available supporting cost recovery. This includes an increase in conversion rate from 14% to 46%, and a decrease in the average time to process enrollments from an average of seven days to one day. There was also a 50% increase in enrollments in the year after the webpage went live as compared to the previous year. Since the program's 2023 relaunch, 98% of customers have enrolled through the self-service channel that was set up in 2021. This demonstrates that the 2021 investments added value to the program, and were reasonable and prudent, so recovery should be approved (Farrell, 6T 2681-82, 2721).

[81] The amount is based on a January 1, 2025 balance of $1,081,737, and a December 31, 2025 balance of $747,158. $334,579 should be added to depreciation expense (Farrell, 6T 2682, n 1).

Other DR programs and pilots (Exhibit A-12, Schedule 5.6, line 3) include: (1) the C&I Dashboard, (2) replacement of LCDs in the interruptible water heating program (both of which were pre-approved in the Company's most recent IRP settlement (Case No. U-21193), and (3) existing ongoing pilots. The Company seeks recovery for additional capital spending on the C&I Battery Pilot, which is discussed in the subsection below. DTE Electric is forecasting to spend $6.9 million during the bridge period of January 2023 through December 31, 2024, and $1.4 million for the projected test year on these programs and pilots (Farrell, 6T 2671, 2683-86; Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, columns (e) and (f)).

As indicated above, 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 (Farrell, 6T 2704). The Commission has generally been supportive; however, in Case No. U-21297, Staff "recommend[ed] 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" (Case No. U-21297 Rogers, 7T 4664, 4666). The PFD agreed (U-21297 PFD, p 347) as did the Commission (December 1, 2023 Order in Case No. U-21297, p 143).

The Company seeks capital cost recovery, but unlike Case No. U-21297, does not seek to recover capital costs related to additional energy bridges or expansion of the program. Instead, to keep the program available for existing customers, the Company seeks to recover those costs related to app maintenance, software licensing, and customer support, which are forecast to be $1.4 million

during the bridge period, and $1.6 million in the projected test year (Exhibit A-12, Schedule B5.6, page 1, line 5, columns (e) and (f)). These costs are justified because in 2023, the program saw an increase of over 110,000 authenticated household downloads (47% increase) and over 18,000 authenticated households with energy bridges (48% increase), which show that customers continue to gravitate to the program (Farrell, 6T 2706-2708).

i. C&I Battery Storage Pilot

As discussed previously in Case Nos. U-20836 and U-21297, DTE Electric's C&I battery storage pilot is a behind-the meter (BTM) lithium-ion battery storage system (BESS) at two C&I customers' sites. The pilot is designed to test the ability to achieve peak demand shaving or shifting during DR events (Farrell, 6T 2686, 2711). Staff previously "support[ed] the idea of the pilot," but recommended that the Commission deny the pilot based on the belief that the Company's proposal lacked specific details about how the pilot will be operated or implemented (Case No. U-20836, Matthews, 8T 5282-5283). The PFD in Case No. U-20836 recommended that the Commission disallow the proposed funding, but that the Company could resubmit the proposal once additional details are developed (Case No. U-20836 PFD, pp. 543-44). The Commission agreed (Case No. U-20836 Order dated November 18, 2022, p. 316).

Based on this direction, the Company resubmitted its proposal with additional detail in Case No. U-21297. Staff again was partially supportive, acknowledging the Company's progress, but recommended "disallowing one half of the pilot expenses" 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" (U-21297 Matthews, 7T 4565-66). The PFD agreed (Case No. U-21297 PFD, pp 583-84), as did the Commission, in adopting a $1,990,360 disallowance (December 1, 2023 Order in Case No. U-21297, p 141).

Here, the Company seeks recovery of the remaining amount. Both batteries have arrived in the U.S. The switchgear has been approved and ordered. Installation at the first customer's site has taken longer than anticipated but is targeted for Q2 2025. The Company is confident that a second participant will be identified, and that the second battery will be installed shortly after the first. The Company plans for both batteries to be operational by the end of 2025. The Company anticipates spending $1.4 million during the bridge period to procure and install equipment, and $0.6 million in the projected test year primarily to support final installation costs. Therefore, the Commission should approve the additional cost recovery for the pilot (Farrell, 6T 2686-89).

Staff "recommends the Company limit the current pilot to a single participant given the difficulty the Company has experienced in finding a willing second participant to date," and based on this recommendation Staff also recommended a $2.0 million disallowance ($1.4 million in the bridge period, and $0.6 million in the projected test year). (Mathews, 6T 5167, 5170. See also MEIBC witness Sherman, 6T 4100).

While a second participant is yet to be confirmed, the Company continues to work diligently. The Company continues to have conversations with interested customers and is working to identify and engage potential participants. Proceeding with only one participant as Staff suggests would be inappropriate and disengaging to the potential participants who have been approached by the Company and are either looking for funding opportunities or seeking approval from their executive management to participate. Additionally, it is important to have a second participant with a different load profile and operating characteristics. Having two participants with such differences will allow the Company to increase its learnings from the pilot when it comes to battery operations, customer savings, and load shift ability (Farrell, 6T 2713). Therefore, the Company should receive full recovery for the pilot (Farrell, 6T 2713-15).

Staff also recommended that the Company charge a fee to the participating customer(s), reasoning that "the customer would be accustomed to a fee and using the battery to recoup its costs," which "may make the customer more likely to retain the battery," and that "Staff finds it critical to test whether payments for participation would impact the customer's utilization of the battery" (Matthews, 6T 5169). The Company disagrees as participants already pay an estimated $100,000 to $150,000 in up-front costs associated with the concrete pad and necessary electrical work. Staff also observed that the Company has had difficulty in finding a second participant, and charging a fee would only further hinder the Company in this endeavor (Farrell, 6T 2713-14).

ii. Residential Generator Pilot

The Company partnered with Generac Grid Services on this pilot to shift customers' electric load to the customers' generators during peak events. The Commission previously approved the pilot (December 1, 2023 Order in Case No. U-21297, pp 252-253), and phase two is scheduled for later this year, which will target enrolling an additional 200 participants (Farrell, 6T 2715)

Ann Arbor witness Stults asserted that the pilot and its costs should be disallowed (Stults, 6T 4246), echoing the DAAO's unsuccessful arguments from Case No. U-21297. Witness Stults appears to misunderstand the pilot in suggesting that it does not align with the Company's climate goals (Stults, 6T 4273). The pilot targets customers who already have a whole-home generator. Therefore, the pilot would not incentivize any customer to purchase and install a natural gas generator. The pilot simply targets customers who already have the technology and incentivizes them to let DTE Electric shift their whole-house load to their generator during DR events. This also lowers the amount of new firm capacity that the Company requires, which allows for additional intermittent renewable resources, helping the Company achieve its clean energy goals (Farrell, 6T 2716).

Witness Stults suggested that the Company should instead explore a similar pilot using batteries instead of generators (6T 4273). The Company finds merit in exploring residential batteries but remains focused on learning as much as it can from the residential generator pilot before turning its attention to another whole-home pilot (Farrell, 6T 2717). The Commission observed in response to DAAO's similar alternative proposal to the residential battery pilot, "[w]hile the DAAO's proposed battery-based pilot is interesting, the potential of a battery-based pilot in the future does not render the immediate proposal unreasonable or unjust. . . . Accordingly, the Commission approves DTE Electric's residential generator pilot . . . ." (December 1, 2023 Order in Case No. U-21297, pp 252-53).

Therefore, the Commission should approve full funding for the Company's pilot and reject Ann Arbor's proposal to create an alternative pilot.[82]

iii. Other DR Proposals

GLREA witness Richter suggested that the Commission direct the Company, in its next rate or demand response case, to propose a pilot of a critical peak (CP) rebate program (Richter, 6T 4841), and a grid interactive water heater (GIWH) pilot (Richter, 6T 4847). The proposed directive would be inappropriate, but the Company appreciates GLREA's suggestions and will keep them in mind for potential future pilot opportunities (Farrell, 6T 2718).

For both suggestions, GLREA witness Richter further asserted that "[i]f the Company resists, the Commission should create the opportunity for a third-party aggregator to do so" (Richter, 6T 4841, 4847). The Company disagrees because allowing a third party aggregator to

[82] The Company further notes that if the Commission were to approve some alternative involving additional costs, then corresponding cost recovery must also be provided, as discussed above in section III.

conduct a residential DR pilot as GLREA suggests would violate the Commission's decisions in Case No. U-21099 (Farrell, 6T 2718).[83]

CEO witness Volkmann recommended that the Commission require the Company to "[w]ork with Staff and interested stakeholders to design a VPP [virtual power plant] pilot/demonstration project for resilience and peak load reduction use-cases using a third-party aggregator, and to include the pilot/demonstration in its 2025 DGP" (Volkmann, 6T 3264). The Company disagrees because residential DR aggregation is currently banned in Michigan, as discussed above. The proposed requirement is also unnecessary in light of the Company's array of DR offerings and other DR activities (Farrell, 6T 2719-20).

Staff recommended that "the Company expand its analysis of the cost effectiveness of its DR programs to include all DR programs, as well as interruptible rates . . . [and] include this analysis in its next DR Reconciliation or General Rate Case, whichever happens sooner" (Doherty, 6T 5076-77).

The Company agrees to expand its cost effectiveness test to include all DR programs, including its DR tariffs; however, any discussion of cost-effectiveness should remain only in DR reconciliation cases, and not be pulled out of the dedicated DR context for inclusion in more complex rate cases (Farrell, 6T 2722).

7. Information Technology

DTE Electric's Information Technology (IT) investment spending is part of the DTE Five-Year IT Plan, which categorizes IT investments into an IT Investment Portfolio with IT Investment

[83] The Commission's December 21, 2022 Order in Case No. U-21099 *et al*, partially lifted the ban on DR aggregation for commercial and industrial retail electric customers. The Commission later provided some additional clarity, including that "for the foreseeable future and until adequate progress is made by utilities, ARCs [aggregators of retail customers], the RTOs, and the Staff in addressing issues with DR aggregation, it does not intend to lift the ban for bundled retail residential customers" (February 23, 2023 Order in Case No. U-21099 *et al*, p 16).

Categories (see, e.g., Sharma, 6T 2026, 2031-32; Hatsios, 6T 2189-90). Total IT capital spending was $224.3 million in 2022, and is projected to be $314.6 million for the 24-month period ending December 31, 2024, and $145.7 million for 2025 (Sharma, 6T 2024; Exhibit A-12, Schedule B5.7, p1, line 11, columns (b), (e), and (f)).

DTE Electric has a robust IT capital investment planning process. All IT projects proceed through the Annual Planning Cycle (APC) cadence. Regulatory/Compliance projects are categorized as non-Discretionary. Discretionary projects undergo a more rigorous analysis and review of both qualitative and quantitative benefits across seven weighted benefit categories, resulting in a Project Prioritization Score (PPS). (Sharma, 6T 2026-29, 2180).

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, Schedules N1 and N1.1 present the executive summaries for each business case associated with each IT project over $250,000.[84] Exhibit A-24, Schedules N3 and N3.1 provide a greater level of detail for each of the IT projects, presented by year and then in portfolio/project order. Various projects were approved for cost recovery in Case Nos. U-21297 and U-20836, as summarized in the tables at Sharma, 6T 2037-39, and Hatsios, 6T 2194. Where the Company seeks additional recovery, see Exhibit A-24, Schedule N2 (Historical Spend Variance Summary) and the Tables at Sharma, 6T 2159, and Hatsios, 6T 2282-83.

Witness Sharma provided an overview of the most significant investments in each of the IT capital portfolios listed on Exhibit A-12, Schedule B5.7, page 1, lines 2-10, organized into the categories of Regulatory Compliance, Sustainment, Return-to-Health, IT Enhancements, Strategic,

[84] There are also projects with IT capital spending less than $250,000, but which are necessary investments to collectively support the IT Portfolio (Sharma, 6T 2158; Exhibit A-12, Schedule B5.7, page 1, line 18).

and IT Projects less than $250,000, as indicated above and summarized at Exhibit A-12, Schedule B5.7, page 1, lines 13-18 (Sharma, 6T 2036). In summary:

1. The Corporate Applications Portfolio encompasses assets used by the enterprise to execute critical internal business functions. It supports business units such as Human Resources, Finance and Controller, Legal, Supply Chain, Fleet and Facilities, and IT assets used by the entire enterprise. Capital expenditures were $17.1 million in 2022, and are projected to be $17.7 million in the 24 months ending December 31, 2024, and $12.4 million in 2025 (Sharma, 6T 2039-40; Exhibit A-12, Schedule B5.7, page 1, line 2, columns (b), (e), and (f); and Schedule B5.7.1, line 27, columns (d), (g), and (h)). Details regarding the projects grouped by category are at Sharma, 6T 2041 (Regulatory/Compliance), 6T 2042-46 (Sustainment), 6T 2047-48 (Return-to-Health), 6T 2048-49 (IT Enhancements), and 6T 2050-55 (Strategic).

2. The Customer Service Portfolio consists of key systems integrating with the Company's SAP Customer Relationship and Billing (CR&B) platform. Witness Sharma supported capital expenditures in the Sustainment and Return-to-Health categories, which were $21.6 million in 2022, and are projected to be $51.5 million in the 24 months ending December 31, 2024, and $18.5 million in 2025 (Sharma, 6T 2055; Exhibit A-12, Schedule B5.7, page 1, line 3, columns (b), (e), and (f); Exhibit A-12, Schedule B5.7.2, line 27, columns (d), (g), and (h)). Details regarding projects grouped by category are at Sharma, 6T 2056-69 (Sustainment), and 6T 2069-2076 (Return-to-Health).

   Company witness Hatsios supported the Customer IT Portfolio and capital investments in the Regulatory & Compliance, IT Enhancements, and Strategic categories, which were $62.1 million in 2022, and are projected to be $74.6 million

in the 24 months ending December 31, 2024, and $33.0 million for 2025 (Hatsios, 6T 2186-87, 2190-93; Exhibit A-12, Schedule B5.7, page 1, line 4, columns ((b), (e), and (f); Exhibit A-12, Schedule B5.7.3, p 1, line 50, columns (d), (g), and (h)). Details regarding the scope of the projects, the expected outcomes enabled by the projects, and forecasted benefits to DTE customers are at Hatsios, 6T 2195-2229 (Digital Self-Service Projects), 6T 2229-45 (Operational Efficiency Projects), 6T 2245-68 (Projects that Enhance Customer Interactions), and 6T 2268-80 (Regulatory and Compliance, including Clean Energy Projects).

3. The Plant and Field Portfolio supports IT business systems that are used by organizations such as Distribution Operations (DO), Energy Supply (ENS), Generation Optimization (GenOpts), and Fermi. Capital expenditures were $58.9 million in 2022, and are projected to be $47.7 million in the 24 months ending December 31, 2024, and $22.6 million in 2025 (Sharma, 6T 2076-77; Exhibit A-12, Schedule B5.7, page 1, line 5, columns (b), (e), and (f); Exhibit A-12, Schedule B5.7.4, line 40, columns (d), (g), and (h)). Details regarding projects grouped by category are at Sharma, 6T 2078 (Regulatory/Compliance), 6T 2079-91 (Sustainment), 6T 2091-94 (Return-to-Health), 6T 2094-95 (IT Enhancements), and 6T 2095-2100 (Strategic).

4. The Information Technology for IT Portfolio consists of investments made within IT for the enterprise as a whole, or that enable the functioning of the IT Department in support of the overall Company. Capital expenditures were $5.2 million in 2022, and are projected to be $19.1 million in the 24 months ending December 31, 2024, and $2.1 million in 2025 (Sharma, 6T 2100-2100; Exhibit A-12, Schedule B5.7, p 1, line 6, columns (b), (e), and (f); Exhibit A-12, Schedule 5.7.5, line 8, columns (d),

(g), and (h)). Details regarding projects grouped by category are at Sharma, 6T 2102 (Sustainment), and 6T 2102-2103 (Strategic).

5. The Information Protection & Security (IPS) Portfolio is focused on the reliability of security infrastructure and improving the Company's overall security posture in IT and Operational Technology (OT). Capital expenditures were $6.1 million in 2022, and are projected to be $10.6 million in the 24 months ending December 31, 2024, and $7.2 million in 2025 (Sharma, 6T 2103-2104; Exhibit A-12, Schedule B5.7, p 1, line 7, columns (b), (e), and (f); Exhibit A-12, Schedule B5.7.6, line 20, columns (d), (g), and (h)). Details regarding projects grouped by category are at Sharma, 6T 2105-2108 (Regulatory/Compliance), 6T 2108-10 (Return-to-Health), 6T 2110 (IT Enhancements), and 6T 2111-17 (Strategic).

6. The Infrastructure Operations Portfolio is responsible for the design, implementation, and secure operation of the Company's overall IT infrastructure. Capital expenditures were $45.1 million in 2022, and are projected to be $87.8 million in the 24 months ending December 31, 2024, and $48.3 million in 2025 (Sharma, 6T 2118; Exhibit A-12, Schedule B5.7, page 1, line 8, columns (b), (e), and (f); Exhibit A-12, Schedule B5.7.7, line 50, columns (d), (g), and (h)). Details regarding projects grouped by category are discussed at Sharma, 2119-20 (Regulatory/Compliance), 6T 2120-27 (Sustainment), 6T 2127-41 (Return-to-Health), 6T 2141-43 (IT Enhancements), and 6T 2144-52 (Strategic).

7. The Enterprise Data & Analytics (EDA) Portfolio concerns the construction of the Company's cloud-based and on-premise data platform to enable analytics to drive business value. This requires a data platform for data storage and processing, along with software to manage the data and usage. In order to support data users, the

Company created a team to enable the infrastructure, build integrations to source systems, and subsequently organize, describe, and document the data available on the platform. EDA's mission is to dependably deliver timely, secure, high-quality data to business partners throughout the Company. Capital expenditures were $5.5 million in 2022, and are projected to be $5.6 million in the 24 months ending December 31, 2024, and $1.5 million in 2025 (Sharma, 6T 2152-53; Exhibit A-12, Schedule B5.7, page 1, line 9, columns (b), (e), and (f); Exhibit A-12, Schedule B5.7.8, line 5, columns (d), (g), and (h)). Details regarding projects grouped by category are discussed at Sharma, 6T 2153-54 (Sustainment), and 6T 2154-55 (IT Enhancements).

8. The Innovations Portfolio applies innovation to deliver rapid value with shorter development cycles and time-to-value, to addresses customer and business challenges that cannot be solved with traditional approaches. The Company seeks to recover the $2.8 million that it spent on Innovation investments in the 2022 historical test year (Sharma, 6T 2155; Exhibit A-12, Schedule B5.7, line 10, column (b); Exhibit A-12, Schedule B5.7.9, line 4, column (d)). Details regarding the Applied Innovations Team and the solutions that were developed through the Innovation project are discussed at Sharma, 6T 2156-58.

In addition to providing data on new investments, the Company also addressed the cost variance for capital investments greater than $0.5 million, approved in the prior rate case, where there is more than a 20% variance from the projected budget and for which the Company is seeking additional recovery. The Company spent $224.3 million of capital on IT projects in 2022, compared to the $165.0 million authorized in Case No. U-21297 (Sharma, 6T 2158-59; Hatsios, 6T 2280-81; Exhibit A-24, Schedule N2, line 18). Company witnesses Sharma and Hatsios sponsored Exhibit

A-24, Schedule N2 identifying the portion of the variance that occurred in each project and explained the major factors that contributed to the variance in each project discussed by each witness, as summarized by the tables at Sharma, 6T 2159; and Hatsios, 6T 2282-83.

i. IT Projects with a Level 2 Cost Estimate

Staff proposed a 20% ($42.6 million) capital expense disallowance ($22.433 million in 2024; $20.169 million 2025) for 102 projects with Level 2 cost estimates, reasoning that they are "more than a year before they are ready for implementation" (Rogers, 6T 5112).

The Company disagrees because the Level 2 projects were subject to and have obtained comprehensive review through the APC process. 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 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 (Sharma, 6T 2169).

Staff also arrived at a its proposed 20% disallowance by equating the Level 2 cost estimates with the American Association of Cost Engineering (AACE) Class 3 estimates, and using the "lower bound of -20%" as the basis for its proposed disallowance (Rogers, 6T 5114). Even assuming the AACE 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 (Sharma,6T 2166-67).

With regard to Staff's proposed $22.4 million disallowance for 2024, witness Sharma further explained that when this case was filed, 78 projects were submitted with a Level 2 estimate. Since then, all of the projects have undergone additional reviews and progressed to Level 3, with 46 of the projects having 0 variance, and the other 32 within the AACE class 1 (less than 10%) variance. Therefore, at a minimum, $20.9 million of Staff's proposed $22.4 million proposed disallowance for 2024 should be rejected (Sharma, 6T 2168).

ii. IT Projects with a Level 3 Cost Estimate

Staff proposed a 10% ($12.68 million) capital expense disallowance ($11.315 million in 2023; $0.546 million in 2024; $0.823 million in 2025) for 104 projects with Level 3 cost estimates, based on comparing actual 2022 costs with the Level 3 cost estimates for 2022 in Case No. U-21297 (Rogers, 6T 5116-17).

Staff's methodology provides only a partial view of total project costs, so it does not support Staff's proposed blanket disallowance. Instead, the total costs approved for cost recovery in Case No. U-21297 should be compared to costs submitted as part of this Case No. U-21534 within the 36 months ending December 31, 2024. The Company did so for all 70 projects identified as over-recovered in Exhibit S-15.6, showing that 49 were within the variance specification allowance, so they should not be considered as part of the over-recovery (Sharma, 6T 2170-71; Exhibit A-46, Schedule KK4).

The Company also explained why variances greater than 20% occurred for 13 projects.[85] Some of the variances were a result of efficiency gained during project planning and execution, which should not be held against the Company, so these projects should also not be used for a

[85] Company witnesses Sharma and Hatsios sponsored Exhibit A-24, Schedule N2 identifying the portion of the variance that occurred in each project, and explained the major factors that contributed to the variance in each project discussed by each witness, as summarized by the tables at Sharma, 6T 2159; and Hatsios, 6T 2282-83.

blanket disallowance. The remaining projects fall into the under-recovery category due to partial or full disallowance in Case No. U-21297, after having been initiated anticipating approval. Therefore, Staff's proposed 10% disallowance should be rejected (Sharma, 6T 2171-72).

iii. Staff's Proposed Individual IT Project Disallowances

a. Digital Worker Experience Electric EOL

The Company issues, supports, and maintains over 14,000 Company-owned endpoint devices (desktop computers, laptops, tablets, smart devices, and ruggedized field computers). This project (previously Endpoint End of Life Electric) replaces 20% of the devices each year to maintain the asset refresh rates of 95% of devices greater than 5 years old. The plan also adds 25 units per year for new hires, and replaces 100 units per year that are damaged or destroyed through normal use (Sharma, 6T 2131-32; Exhibit A-24, Schedule N3, lines 304-307).

Staff proposed "a disallowance of $1.903 million in the bridge period ($0.943 million in 2023 and $0.960 million in 2024) and $1.041 million in the 2025 test year," which it calculated based on the Company's response to an audit request for "the cost of each individual laptop, desktop, monitor, and tablet" (Rogers, 6T 5120-21).

Staff's calculation is inaccurate because the audit response included only the devices' unit costs, and not the additional labor costs required for configuration, deployment, and testing of the devices. The device costs plus the additional labor costs equals the total cost reflected in Exhibit A-24, Schedule N3, lines 304-306. Therefore, Staff's proposed disallowance should be rejected (Sharma, 6T 2173-74).

b. End of Life Asset Replacements

This project will replace servers, storage, databases, and operating systems that are at the end of their serviceable life (Sharma, 6T 2132-33; Exhibit A-24, Schedule N3, line 311).

Staff "recommends a $0.5 million disallowance for the 2022 historical year," as the difference between the $6.1 million to purchase a three-year license of VMWare in 2022, and the Company's 2025 request for $5.6 million to renew that three-year license (Rogers, 6T 5122-23).

The Company disagrees because the 2022 license cost is accurate. The Company is engaged in vendor negotiations with a focus on increasing efficiency and managing workload with other available technologies to possibly reduce the VMWare license renewal costs license by $0.5 million in 2025. Therefore, the Commission should reject Staff's proposed $0.5 million disallowance for 2022 historical costs because the Company reasonably incurred $6.1 million in costs for the purchase of the three-year license in 2022 and basing a disallowance on future expected savings to be obtained through negotiations for VMWare licensing renewal in 2025 is not appropriate (Sharma, 6T 2175).

iv. AG's proposed disallowances

a. Customer IT Projects

The AG proposed disallowances of $5,750,000 for 2024 and $15,393,000 for 2025 for "four projects" consisting of three Michigan Green Power (MIGP) projects (Exhibit A-12, Schedule B5.7.3, lines 4, 11, and 15) and the 2025 Advanced Analytics (AA) Use Case for Reducing MPSC Complaints ($1.0 of the $3.0 million in Exhibit A-12, Schedule B5.7.3, line 18), asserting that "[g]iven that these projects have not started the initial scoping phase, are in the early phase of development, or will not be completed by the end of the projected test year, it is premature to include the forecasted capital expenditures in rate base" (Coppola, 6T 3630).

As a preliminary matter, the AG's proposed disallowance is overstated because it goes beyond the four projects at issue by including $2.0 million for the 2024 Advanced Analytics Use Cases Implementation project (Described at Hatsios, 6T 2224, 2234-35) and $2.01 million in 2025 IT capital for the other 2025 Advanced Analytics Use Case (described at Hatsios, 6T 2236), neither of which the AG recommends for disallowance in testimony. Therefore, the total capital associated with the four projects for which the AG recommends disallowances is $3.75 million in 2024 and $13.39 million in 2025 (Hatsios, 6T 2306-07).

The Company does not dispute the AG's proposed disallowance of $3.9 million in 2025 IT capital associated with the MIGP Scope 3 Billing and Enrollment project (Exhibit A-12, Schedule B5.7.3, line 11). The project has been rescheduled to begin in 2026, and the Company withdraws its request for capital recovery in this case (Hatsios, 6T 2308).

The Company is investing $2.7 million in the 2023-2024 bridge period, and $5.5 million in the 2025 test year in the MIGP Customer-Requested Renewable Energy Projects (Hatsios, 6T 2270-71, Exhibit A-12, Schedule B5.7.3, line 4). The requested capital represents two contracts with companies to build two dedicated solar parks with 650 MW and 400 MW of capacity, respectively, to offset the customers' electricity use with green energy. Given the prior approval of the project capital in Case No. U-21297 as a Level 2 project, and the contracted nature of the project, the Company is mandated and committed to make these investments. The 2024-2025 project also kicked off on August 1, 2024, is progressing according to its timetable (provided on Exhibit AG-13, p 5), and is on-track to go live by November 30, 2025. Therefore, the AG's proposed disallowance should be rejected (Hatsios, 6T 2308-09).

The Company is investing $1.9 million in the 2023-2024 bridge period, and $3.0 million in the 2025 test year in the Rider 17 – MIGP, Residential and Small Commercial & Industrial Project (Hatsios, 6T 2274, Exhibit A-12, Schedule B5.7.3, line 15). Given the regulatory nature of this

project and its prior approval in Case No. U-21297 as a Level 2 project, the Company is mandated and committed to making these investments. The project is also not in some early stage as the AG incorrectly suggests. The project is essentially one multi-year project with annual releases of system enhancements based on customer demand for renewable energy and renewable energy pricing. The 2024 phase kicked off in February 2024, and is progressing per its timetable to go live by November 30, 2024. The 2025 phase will start in January 2025 when annual funding of IT capital is available and is scheduled to go live by November 30, 2025. Therefore, the AG's proposed disallowance should be rejected (Hatsios, 6T 2309-11).

The Company is investing $1.0 million in the 2025 Advanced Analytics Use Case for Reducing MPSC Complaints (Hatsios, 6T 2235, Exhibit A-12, Schedule B5.7.3, line 18), which will leverage machine learning to reduce MPSC complaints. It is on track to start in March 2025, and go-live by December 1, 2025. Therefore, the AG's proposed disallowance should be rejected (Hatsios, 6T 2311-12).

b. Enhanced Document Management Capability Projects.

AG witness Coppola proposed disallowances of $1,218,000 for 2024 and $2,958,000 for 2025 associated with two projects in Schedule B5.7.1: (i) Line 9 - Cloud Health and Safety, with capital expenditures of $2,518,000 in 2024 and $582,000 in 2025; and (ii) Line 16 - Enhanced Document Management Capabilities projects, with capital expenditures of $1,218,000 in 2024 and $2,958,000 in 2025 (Coppola, 6T 3632). In support of the proposed disallowances, AG witness Coppola claimed that the Company did not provide sufficient information for these projects in discovery, which prevented him from determining what phase the projects are currently in or whether they will be completed by the end of the test year. *Id*.

DTE Electric disagrees with the AG's proposed disallowances because they are based on the incorrect claim that the Company dismissed the AG's "request to provide the project phases with related timeline and the current phase of the project" (Coppola, 6T 3631). Instead, there was a misalignment between the AG's discovery request and the Company's response because the AG's discovery request referenced "Customer Services IT projects," but the Cloud Health and Safety, and Enhanced Document Management Capabilities projects are "Corporate Applications IT projects" (as reflected, for example, by their positions in witness Sharma's direct testimony). Thus, the Company supplied the requested information, as opposed to dismissing the discovery request. Moreover, witness Sharma sponsored Exhibit A-46, Schedule KK2 in his rebuttal testimony, which provided information regarding the Cloud Health and Safety and Enhanced Document Management Capabilities projects that the AG intended to request in discovery. Therefore, the projects are supported by the record, and the AG's proposed disallowance for the Enhanced Document Management Capabilities project should be rejected (Sharma, 6T 2047-48, 2050-51, 2176-78; Exhibit A-46, Schedule KK2).[86]

c. 2023 Capital Expenditures.

AG witness Coppola proposed a $34,854,000 disallowance, asserting:

> In discovery, the Attorney General asked the Company to provide the actual amount of capital expenditures incurred in 2023 in the Information Technology area. The information provided in response to the discovery request shows that for 2023 the Company incurred actual capital expenditures of $127,456,000. In comparison, the Company had forecasted $162,310,000 for the year in Exhibit A-12, Schedule B5.7. The difference of $34,854,000 should be removed from rate base in this case. [Coppola, 6T 3632-33, citing Exhibit AG-15]

[86] The same result applies to the extent that the AG suggests a disallowance for the Cloud Health and Safety project, although she did not explicitly propose a disallowance (Coppola, 6T 3632, quoted above).

The Company disagrees because the AG improperly compared 2023 total projected capital expenditures to 2023 Shared Assets actuals. An appropriate comparison is 2023 total projected capital expenditures ($162,310,000) to 2023 total actual costs ($177,344,000). Therefore, the AG's proposed disallowance is based on an incorrect data comparison and should be rejected (Sharma, 6T 2178-79; Exhibit A-12, Schedule B5.7, p 1; Exhibit A-46, Schedule KK3)

v. DAAO's proposed disallowances

a. Collection Digital Self-Service.

Mr. Hatsios' revised direct testimony extensively discussed the Company's investments in its digital self-service solutions to provide customers with seamless and satisfying self-service alternatives to having to call the Contact Center, both to meet the demands of those customers who prefer to engage with the Company in a self-service channel, and to reduce the volume of live calls handled by the Company's Customer Representatives (CRs) (Hatsios, 6T 2195-2229). The Company will invest $10.7 million from 2022-2025 in five projects to enhance the Company's existing Collection Digital Self-Service solutions, and to expand the number of available digital solutions (Hatsios, 6T 2204-08; Exhibit A-24, Schedule N3.1, lines 13-15, 20, 25, 41).

DAAO proposed a complete $10.7 million disallowance for Collection Digital Self-Service based on a number of concerns (Koeppel, 6T 4398-4402); with substantially the same concerns indicated by Jacob, 6T 4653, 4655, 4658, 4662. The Company disagrees because none of DAAO's indicated concerns have merit. The record instead demonstrates that the Company's Collection Digital Self-Service investments benefit customers, satisfy the needs of customers who choose to engage in a digital self-service solution, and provide substantial savings that are passed on to customers. Therefore, DAAO's proposed $10.7 million disallowance should be rejected, as further discussed below.

DAAO witness Koeppel first suggested that the Company's investments "may be subject to diminishing returns and may not generate the full scale of benefits that the company claims" (Koeppel, 6T 4398). Instead by 2027, the Company forecasts reaching an overall Digital Engagement Rate (DER) of 76% across the key customer transactions, which is 7% above the 2023 overall DER of 69%. As a result of DER increases, the Company is committed to call volume reduction savings, resulting in total cumulative 2022-2027 O&M cost saving of $15.7 million (Exhibit A-24, Schedule N5, page 1, line 16, column (h)). The Company also removed $6.4 million from the Company's requested O&M recovery in this case (Hatsios, 6T 2204, 2314-15; Exhibit A-24, Schedule N5, page 1, line 17, column (f); Exhibit A-13, Schedule C5.7, line 5, column (k)).

DAAO witness Koeppel also incorrectly suggested that the Company "may be reaching a saturation point in terms of the adoption and utilization of its self-service options by customers" (Koeppel, 6T 4398), as Mr. Hatsios explained (Hatsios, 6T 2315-16).

DAAO witness Koeppel next acknowledged that "collection DERs are increasing," but suggested that "actual call volumes are not diminishing" (Koeppel, 6T 4399). To the contrary, in 2023 despite increased numbers of low-income customers, increased numbers of low-income customers entering final arrears, and reduced energy assistance funding, the Company handled 43,500 fewer Collection calls than it did in 2022. In 2024, the Company forecasts reducing Collection call volume by 133,000 calls, and has already realized a reduction of 77,000 calls. This will bring the total 2023-2024 reduction in calls to 176,500, which is about 50% of the Company's 2023-2027 projection, with corresponding O&M savings (Hatsios, 6T 2207, 2316-17; Exhibit A-24, Schedule N5, page 2, lines 10 and 18).

Witness Koeppel next suggested that the Company's investments "are not necessarily aligned with the broader goals and priorities of the Commission and other stakeholders in terms of advancing energy affordability, equity, and sustainability in Michigan" (Koeppel, 6T 4399). The

Company maintains that it is providing equitable opportunities for low-income and other vulnerable customers to have access to, and the same opportunity to choose to engage in, the same convenient and easy-to-use Digital Self-Service solutions as any other customer who finds themselves struggling to pay or in some step of the Collection process. Also, the realized and forecasted Collection call volume reductions result in significant O&M savings, which are passed on to all customers as discussed above (Hatsios, 6T 2317-18).

Finally, DAAO witness Koeppel suggested that the Company seeks to "make its collection process more automated, efficient, and aggressive," and thereby "prioritizes the company's own financial interests over the needs and well-being of its customers" (Koeppel, 6T 4400-01). This suggestion is incorrect and unfounded. The Company has designed and implemented every one of its implemented and planned Collection Digital Self-Service solutions with the needs of customers top-of-mind. Also, in no way has the Company's standard collection or disconnect policies and practices changed between a transaction that is handled digitally or through a call. Customers choose which channel best meets their needs.[87] The rapid growth in Collection digital engagement by customers further demonstrates that customers see value in these technologies, and that the technologies meet customer needs (Hatsios, 6T 2206, 2319-20. Exhibit A-44, Schedule II1 provides further details regarding these digital improvements and their customer benefits). Even DAAO witness Koeppel went on to acknowledge that "[i]n general, I think that improving these systems is beneficial to customers" (Koeppel, 6T 4402).

[87] Digital self-service is complementary to the support provided by the Contact Center. By, 2027, even with projected call volume reductions, the Company still expects to handle 2.7 million calls annually, 945,000 (35%) of which will be collection calls. Thus, the Company is not planning to de-prioritize or no longer answer calls. Customers can always choose to call the Contact Center and speak to a CR if they are uncomfortable using a digital solution, do not have access to a computer or the internet, or simply would prefer to talk with somebody to manage their Collection inquiry or request. The Company also anticipates that customers will use the digital channels to self-serve simpler transactions, which will reduce wait times, and allow the CRs to focus on handling more complicated customer requests (Hatsios, 6T 2321, 2324-25).

Mr. Hatsios also responded to other Intervenor questions, concerns, and assertions about the level of Customer IT capital expenditures (Hatsios, 6T 2325-26), and the safety and location of DTE Kiosks (Hatsios, 6T 2327-28). The Company agrees with Staff's request (Klocke, 6T 5103-04) that the Company further describe and provide updates regarding its ongoing efforts to improve the outage customer experience (Hatsios, 6T 2328-30).

8. Corporate Staff Group

Corporate Staff Group (CSG) capital spending for physical infrastructure, fleet, and other projects was $126.6 million in 2022, and is projected to be $235.8 million for the 24 months ending December 31, 2024, and $120.1 million for 2025 (Uzenski, 6T 1521; Exhibit A-12, Schedule B5.8, p 1, line 7). Company witness Uzenski explained and supported the larger projects included in the categories on Exhibit A-12, Schedule B5.8, page 1, line 1 (Electric Vehicle Fleet), line 2 (Facilities-Construction & Upgrade), line 3 (Service Center Optimization and Modernization), line 4 (Security Measures), and line 5 (Other Miscellaneous). (6T 1521-27).

The AG proposed vehicle fleet capital expenditure disallowances of "$4,564,000 for 2024 and $8,187,000 for 2025" based on a comparison of the Company's request to an average of expenditures during 2021-2023, reasoning that the Company did not provide data on the types of vehicles expected to be purchased in 2025 (Coppola, 6T 3637).

To the contrary, the Company provided a list of vehicle and equipment purchases planned for 2025 in response to Staff's discovery (Exhibit A-37, Schedule BB2), which confirms that the Company has specific vehicle purchases planned for 2025. The Company also explained that it uses a life-cycle model to optimize the total cost of ownership and develop a replacement strategy. This is a more reasonable forecast methodology than the AG's simplistic historical average, so the Commission should reject the AG's proposed disallowance, which was, in any event, founded upon

a mistaken belief that the Company had not provided the specific vehicles it intends to purchase (Uzenski, 6T 1521, 1561, 1564-65).

Staff proposed vehicle fleet disallowances of $2.84 million in the bridge period and $3.83 million in the projected test year "based on historical underspending in 2023 in this category as well as evidence that the Company is again on track to underspend in 2024" (Boutet, 6T 5134).

The Company disagrees because Staff's proposed disallowances are based on only a portion of the total expense, based on an apparent misunderstanding. Staff compared the $29.3 million direct cost of vehicles that the Company purchased in 2023 (Exhibit S-12.6, p 8) to the Company's $32.8 million projection (Exhibit A-12, Schedule B5.8, line 1, column (c)), and concluded that the Company underspent its forecast. Staff's Exhibit reflects only the direct purchase cost of vehicles (which is what the Company understood was requested) and did not include capital maintenance costs or the internal labor costs allocated and capitalized as part of the Company's vehicle fleet. The total actual capital expenditure for vehicle fleet in 2023 was $33.2 million, as reflected in response to the AG's discovery (Exhibit AG-17, p 2). Thus, there was no underspending in 2023. The Company's projection for 2024 provided in response to Staff's discovery (Exhibit S-12.7) similarly did not include capital maintenance, or the internal labor related to the capitalized fleet vehicles. The complete forecast for 2024 is $38.2 million (Exhibit AG-17, p 2). Therefore, Staff's proposed disallowances are inconsistent with the Company's total vehicle costs and should not be adopted (Uzenski, 6T 1561, 1565-66).

The AG proposed disallowances totaling $14,265,000 for office space updates and office equipment, asserting that the Company "had no clear answers" to the AG's discovery regarding why the expenditures are needed, and that they constitute "wasteful spending" (Coppola, 6T 3633-34).

To the contrary, the Company explained and justified the expenditures as reflected in Exhibit AG-16, pp 2-5. The Company had reduced its total office space by selling buildings and terminating leases, and then had to increase the number of workstations within that smaller space to accommodate employees returning to the office after the pandemic. The Company moved from 2,000 reservable workstations to 4,100 workstations assigned to each employee. Additional technology was required to enable more video conferencing for employees in the office with employees working remotely. In addition, the conversion of the open space in the downtown Detroit headquarters lobby was to accommodate large groups that previously used leased space or facilities the Company no longer owns. The Company maintains that its decisions were reasonable, prudent and justified. Therefore, the AG's proposed disallowance should be rejected (Uzenski, 6T 1561, 1566-67).

Therefore, the Corporate Staff Group costs are reasonable, prudent, and should be approved.

VI. RATE OF RETURN[88]

DTE Electric requests a weighted, after-tax 5.92% overall rate of return (Vangilder, 6T 2812; Exhibit A-14, Schedule D1, line 10, column (g)), which the Commission should adopt for the reasons discussed below.

A. Capital Structure

DTE Electric seeks to maintain its permanent capital structure of 50% debt and 50% equity (Lepczyk, 6T 2548, 2551, 2560, 2564; Exhibit A-14, Schedule D1. See also December 1, 2023 Order in Case No. U-21297, p 177). Staff (Ufolla, 6T 5009-10), and the AG (Coppola, 6T 3656) agreed.

[88] See generally supra, Section II. History of Proceedings – *DTE Electric* - Vangilder, Lepczyk, Villadsen; *Attorney General* -- Coppola, *ABATE* – Walters; *Staff* – Ufolla; *Ann Arbor* – Stults; *CUB-MEC* – Bandyk; *Walmart* -- Perry

Although there appears to be no disagreement,[89] the Company notes for completeness that it is important to maintain DTE Electric's capital structure due to the business and financial risks confronting the Company. Capital structure is critical because it determines a company's access to credit markets (i.e., the *availability* of capital), and ability to raise capital at reasonable terms and rates (i.e., the *cost* of capital). Companies with more equity in their capital structures are less risky from a financial perspective, and generally have a greater ability to obtain capital, and lower required returns on equity and costs of debt than companies with weaker capital structures. If DTE Electric is unable to raise adequate capital, then the Company will be unable to invest in the equipment and systems necessary to ensure efficient, reliable and safe electric service for its customers (Lepczyk, 6T 2549-51).

The Company is using the previously authorized capital structure to reduce the number of contested issues in this case, and further notes that the 50% equity ratio is reasonable because it is lower than the 52% average equity ratio for the Company's peers (Lepczyk, 6T 2552, 2564; Exhibit A-14, Schedule D1.1).

DTE Electric also had a 50% equity ratio on December 31, 2022 and is committed to maintaining a 50% equity ratio. DTE Energy made over $2.3 billion of equity infusions from 2018-2022, equity infusions totaling $760 million in 2023, and will infuse the amounts necessary in future years to maintain a 50% equity ratio (Lepczyk, 6T 2553).

In summary, DTE Electric needs a strong equity component of its capital structure to maintain adequate access to capital at the lowest reasonable cost during a period of significant capital investment. DTE Electric also continues to balance capital investment plans, credit metrics and customer rate impacts, while it continues to face significant ongoing and emerging business

[89] ABATE suggested that the Company proposed an equity ratio of 53.5% (Walters, 6T 3445), which is presumably just an error (Lepczyk, 6T 2564)

challenges, as further discussed below regarding Return on Equity (ROE). Accordingly, the Commission should maintain DTE Electric's 50% equity ratio.

B. Debt Cost Rates

1. Long-Term Debt

DTE Electric recommends a 4.24% weighted cost of long-term debt, which was determined using the net proceeds method for each issue including the financing cost of the new issues (Lepczyk, 6T 2549, 2556-57, 2560; Exhibit A-14, Schedule D2). The AG agreed (Coppola, 6T 3657).

Staff proposed 4.21% (Ufolla, 6T 5011-12, 5027). The Company disagrees. Mr. Lepczyk explained that based on an updated yield curve as of August 6, 2024, the Company calculated a long-term debt issuance rate of 5.53% for 2025 (as compared to the 5.62% long-term debt rate for the projected 2025 issuance in the Company's initial filing, and Staff's 5.33% calculation) based on a 4.05% average projected 30-year treasury rate plus 148 bps spread. With these updated projected 2025 issuances and actual 2024 issuances, the weighted average long-term debt cost as of December 31, 2025 approximates the Company's original 4.24% calculation (Lepczyk, 6T 2564-65; Exhibit A-45, Schedule JJ1). Therefore, the Company maintains that 4.24% is appropriate.

2. Short-Term Debt

DTE Electric initially recommended a 5.76% cost of short-term debt, which includes the interest rate on short-term borrowings and facility fees associated with the credit arrangements necessary for the issuance of short-term debt (Lepczyk, 6T 2549, 2557-58, 2560; Exhibit A-14, Schedule D3). The AG agreed (Coppola, 6T 3657).

Staff proposed 4.96% (Ufolla, 6T 5011-12, 5027). The Company disagrees, and now recommends 5.73% based on the July 2024 short-term cost of debt. Mr. Lepczyk explained that due to continuing market volatility, the potential for "higher for longer" interest rates, and consistently over-optimistic forecasts regarding the proximity of rate cuts by the Federal Reserve, the current short-term cost of debt is a more appropriate metric than the market forecast rate. The Company's average borrowing rate in July 2024 was 5.48% (including the Company's actual interest rate spread). The cost of credit facility fees adds 0.25% for a total short-term debt rate of 5.73% (Lepczyk, 6T 2565).

C. Return on Common Equity (ROE)

Company witness Dr. Villadsen explained and recommended that a just and reasonable Return on Equity (ROE) for DTE Electric's common equity capital is 10.5%.[90] This is below the midpoint of a reasonable range and is conservative because DTE Electric has greater-than-average risk (Villadsen, 6T 2407-2408, 2442, 2446, 2490-91).

Staff recommended the current 9.9% (Ufolla, 6T 5009, 5011, 5013, 5026). The AG recommended 9.85% (Coppola, 6T 3593, 3657, 3682-83). ABATE recommended 9.6% (Walters, 6T 3423, 3478). CUB/MEC suggested 9.3% (Bandyk, 6T 3748, 3761). These are the only proposals supported by any analysis.[91]

The most noteworthy aspect of Staff, the AG, and ABATE's recommendations is that they all again recommend higher ROEs than they did in prior cases. In Case No. U-20836, Staff

[90] DTE Electric has no preferred stock (Vangilder, 6T 2815; Exhibit A-14, Schedule D1, line 2).

[91] Ann Arbor (Stults, 6T 4252-56) and Walmart (Perry, 6T 4727-34) suggested that the Company's ROE should either not increase, or be reduced, without a specific number. DAAO suggested 9.18% (Koeppel, 6T 4439). These witnesses did not support their recommendations with a ROE analysis using financial market data. Thus, their unfounded assertions cannot support a decision and merit no serious consideration (Villadsen, 6T 2495, 2497-99). See also section III above.

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). In Case No. U-21297, Staff (Ufolla, Case No. U-21297, 7T 4704, 4720-21) and the AG (Coppola, Case No. U-21297, 6T 3728) recommended 9.8%, and ABATE recommended 9.55% (Walters, Case No. U-21297, 4T 1154-55, 1207). Thus, they all essentially acknowledge that the cost of equity has increased since the Commission maintained DTE Electric's ROE at 9.9% in Case No. U-21297, as well as since the Commission set it previously (Villadsen, 6T 2493, 2496).

Dr. Villadsen also explained that Staff, the AG, ABATE, and CUB/MEC made various modeling choices that downward-biased their results (summarized at Villadsen, 6T 2493-2501), some of which are discussed below where they are best understood in context. CUB/MEC's ROE recommendation is an outlier based on flawed methodologies. Dr. Villadsen explained in part:

> Of particular note, the ROE recommendation of Mr. Bandyk is below that allowed for any integrated electric utility in 2024 except Public Service New Mexico, which is a unique decision that is under appeal at the New Mexico Supreme Court. The recommendation is also well below that of other Staff and Intervenor witnesses indicating that he relies on outlier inputs or models. In this case, the low estimates are predominately caused by Mr. Bandyk exclusive reliance on the multi-stage DCF and an unreliable low MRP in his CAPM. [Villadsen, 6T 2497. Footnote omitted.]

Dr. Villadsen based her recommendation on a sample of 25 integrated regulated electric utility companies that 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, 6T 2428-31). She also discussed Staff and Intervenor samples and criticisms of her sample, but ultimately sample differences are not key drivers of ROE recommendations (Villadsen, 6T 2502-2503).

Dr. Villadsen estimated the ROE for each company in her sample using two versions of both the Capital Asset Pricing Model (CAPM),[92] 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 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, 6T 2414-15, 2436, 2471).

Dr. Villadsen's 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 by at least 50 basis points (Villadsen, 6T 2493, 2496, 2515-26).

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,[93] and (c) a market risk premium (MRP). (Villadsen, 6T 2431-33).

[92] The CAPM is a risk positioning approach. Dr. Villadsen also used the Empirical CAPM (ECAPM) (Villadsen, 6T 2433).

[93]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, 6T 2433).

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 for this by using the ECAPM, which uses these empirical findings to produce results that more closely match the results of empirical tests (Villadsen, 6T 2433-34). Criticisms of the ECAPM are misplaced, but the ECAPM had little if any effect on Dr. Villadsen's estimated ROE, and she relegated her discussion to an appendix (Villadsen, 6T 2436, 2501, 2536-40).

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 2024 - 2025, 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 4.3%. Her Scenario 1 combines the 4.3% risk-free rate with the 7.17% historical average MRP. Her Scenario II combines the 4.3% risk-free rate with Bloomberg's forecasted MRP (over the 20-year Treasury bond yield) of 6.37% (Villadsen, 6T 2435).

The Electric Utility Sample's CAPM-based results are consistent with a cost-of-equity range of 10.75% to 11.75% (rounding to the nearest ¼ percent, which is Dr. Villadsen's practice), before any DTE Electric risks are considered (Villadsen, 6T 2436).

Staff "computes an average CAPM cost of equity of 10.23%, and a median of 10.31%" (Ufolla, 6T 5021). Dr. Villadsen generally agreed with Staff's methodology, explaining only that (apart from the need to take financial leverage into account) Staff's 3.85% risk-free rate is too low, as reflected for example by it being lower than that of other witnesses and lower than the current yield. Using the next-lowest risk free rate (Mr. Bandyk's 4.0%) increases the CAPM-based ROE by 15 basis points (Villadsen, 6T 2508).

The AG's CAPM model indicates a cost of equity of 10.57% (Coppola, 6T 3671). Dr. Villadsen agreed that the AG's CAPM implementation was reasonable, apart from the need to consider financial leverage (Villadsen, 6T 2509).

Dr. Villadsen disagreed with ABATE witness Walters' beta analysis, emphasizing that it is imperative that betas reflect the best estimate of systemic risk. Mr. Walters' use of the historic average of betas since 2014 lacks relevance and downward biases his CAPM results by 0.41% to 1.36% (Villadsen, 6T 2509. See also 6T 2512).

Dr. Villadsen explained that CUB/MEC's CAPM implementation was flawed because (1) Mr. Bandyk relied on an exceptionally-low MRP that is "an outlier at 4.87 percent", and (2) there are inconsistencies in the use of his sources (Villadsen, 6T 2497, 2509-13). She concluded:

> Taken together, Mr. Bandyk's MRP estimate has numerous problems that downwardly bias his ROE estimates to below almost every CAPM estimate put forth by any witness in this proceeding. Simply put, Mr. Bandyk's CAPM estimates should not be given any weight by the Commission.
>
> To account for the downward bias in Mr. Bandyk's CAPM, I implemented it using Staff's MRP of 6.80 percent for a modified CAPM of 10.33 percent and very much in line with the results obtained by other witnesses. [Villadsen, 6T 2511. Footnote omitted.]

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, 6T 2437-38).

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 9.4% to 11.2% for the Electric Utility

Sample (9.5% to 11.25% rounding to the nearest ¼ percent). Dr. Villadsen viewed the multi-stage results (9.4%) 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 narrower range of 10.0% to 11.0% for the Electric Utility Sample, and noted that the average of simple DCF calculations before any financial risk considerations is 10.5%, which is the midpoint of that range (Villadsen, 6T 2438-39).

Dr. Villadsen's rebuttal responded to other witnesses' criticisms and their implementation of DCF models (Villadsen, 6T 2504-2507). The deficiencies in Staff's and the AG's modeling largely concern low growth rates, 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 11.33%, but Mr. Walters calculated a ROE of 9.1%. This is simply inconsistent, so ABATE's sustainable growth model merits no consideration (Villadsen, 6T 2505-2506). CUB/MEC's implementation is downward-biased because it is incomplete and inconsistent, as Dr. Villadsen explained:

> Mr. Bandyk relies on my multi-stage DCF, while Mr. Ufolla, Mr. Coppola, Mr. Walters and I all include a single-stage model. Thus, if Mr. Bandyk wants to use my results and incorporate his adjustment, he ought to use an average of the single-stage and multistage models. Doing so would increase his DCF-based results from 8.66 percent to 9.61 percent with the single-stage DCF resulting in a cost of equity of 10.43 percent. [Villadsen, 6T 2506. Footnote omitted.]

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 10.5% ROE for electric utilities. This is consistent with the estimates from the CAPM and the DCF model for the

Electric Utility Sample (Villadsen, 6T 2440-41). Dr. Villadsen's rebuttal testimony responded to other witnesses' criticisms and the implementation of their models (Villadsen, 6T 2514-16).

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

In DTE Electric's next to last rate case, the PFD "recommend[ed] that the Commission should keep DTE's authorized ROE at 9.90%" (Case No. 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. [November 18, 2022 Order in Case No. U-20836, pp 242-43. Footnote omitted.]

In DTE Electric's last rate case, the Commission disagreed with the PFD's recommendation to reduce the Company's ROE to 9.8%. The Commission instead maintained the ROE at 9.9%, explaining in part:

> The Commission notes that the cost of equity in the utility sector has generally increased over the last year, and further notes that the recommended ROEs provided

> by many parties, while lower than what is being adopted here, were generally higher than what those same parties proposed in previous cases. As such, the Commission finds that based on the record evidence in this case a reduction in the ROE is unwarranted at this time.
>
> Given the above, including DTE Electric's observation of today's financial environment of high inflation and rising interest rates, the Commission finds that the most prudent course of action is to maintain the current ROE. The Commission also again notes that it may revisit this determination in future cases as it gains greater insight into issues currently affecting the financial markets and longer-term macro-economic trends . . . . [December 1, 2023 Order in Case No. U-21297, p 186.]

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" (April 18, 2018 Order in Case No. U-18255, 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" (May 2, 2019 Case Order in No. U-20162, pp 67-68).

In Case No. U-20940 (DTE Gas's most recently completed general rate case), the Commission maintained the ROE at 9.9%, despite the Staff and AG proposing, and the ALJ 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 any decrease.

Dr. Villadsen further explained that in response to persistent high inflation, the Federal Reserve had increased rates eleven times from March 2022 through July 2023. At the same time, systemic risk as measured by beta remains relatively constant,[94] as does the historical market risk premium, so the estimated cost of equity is now higher than it was in the recent past (Villadsen, 6T 2417-27, 2498).

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 declined to follow such arguments in past cases. For example, in Case No. U-18014 (DTE Electric's general rate case prior to U-18255, which is discussed above), the Commission set DTE Electric's ROE at 10.1%, despite the ALJ recommending an ROE of 10.0%, in accordance with Staff's recommendation. In setting the 10.1% ROE, the Commission explained in part that "an ROE of

[94] Beta remains high at 0.93 for the Electric Utility Sample (Villadsen, 6T 2418, 2431), as compared to 0.88 in Case No. U-21297, and approximately 0.6% in Case No. U-20561 where the Commission set DTE Electric's ROE at 9.9%.

10.1% most appropriately compensates DTE Electric for the regional economic and company-specific aspects of risk, while maintaining its ability to attract capital. It also strikes an appropriate balance between the company's interest in investment and the interests of DTE Electric's ratepayers in safe, reliable and affordable energy . . . The Commission, in reaching its determination, also takes into consideration the company's unique circumstances and characteristics, rising interest rates and the standards set forth in *Bluefield Waterworks* and *Hope Natural Gas* . . . Finally, the Commission is confident that this ROE is appropriate given the company's forecasted capital expenditures and its required compliance with environmental regulations." (January 31, 2017 Order in Case No. U-18014, pp 65-66).

In Case No. U-17767 (DTE Electric's general rate case prior to U-18014), the Commission set DTE Electric's ROE at 10.3%, despite the ALJ recommending an ROE of 10.0%, in accordance with Staff's recommendation, explaining in part that "the Commission finds that an ROE of 10.3% will best achieve the goals of providing appropriate compensation for risk, ensuring the financial soundness of the business, and maintaining a strong ability to attract capital . . . DTE Electric has an ambitious capital investment program, much of which is related to environmental and generation expenditures that are unavoidable and are saddled with time requirements" (December 11, 2015 Order in Case No. U-17767, pp 54-55).

More recently, the Commission again recognized that "customers do not necessarily benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner" (May 8, 2020 Order in Case No. U-20561, p 176, citing May 2, 2019 Order in Case No. U-20162, p 67).

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, in addition to ongoing uncertainty in the capital markets discussed above, DTE Electric faces increased risk due to significant capital expenditures needed to transition from coal-fired generation. 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, 6T 2443-46, 2533-34).

5. The Connection Between Equity and Capital Structure

A company's cost of equity and capital structure are inextricably intertwined because the use of debt increases the company's financial risk, and therefore increases the Company's cost of equity. A lower equity ratio component (and a correspondingly higher debt component) in the capital structure creates a higher level of risk for shareholders, and a corresponding need for a higher rate of return on equity. Dr. Villadsen's recommended ROE corresponds to a 50% equity ratio. If DTE Electric has less equity, however (and a corresponding increase in both debt leverage as well as financial risk), then DTE Electric's ROE must increase to compensate for the increased risk. A company with a lower equity share and higher financial leverage must earn a higher ROE in order to maintain the same overall return. (Villadsen, 6T 2411-14).

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

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 Nos. U-20836 and U-21297. The average of the low and high estimates from Dr. Villadsen's DCF, CAPM and Risk Premium models results in a range of 10.2% to 11.1%, the midpoint of which is 10.65%. Dr. Villadsen's 10.5% recommendation for DTE Electric's ROE is conservative because it is below the midpoint of the

ROE range, and DTE Electric has higher-than-average risk compared to the sample companies (Villadsen, 6T 2446).

Proposals to maintain or lower DTE Electric's ROE are also inappropriate in today's financial environment and considering the Company's business risk (Villadsen, 6T 2492-93). 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, which is particularly critical during a period forecast to have substantial capital investment for infrastructure.

D. Other Cost Rates

Tax law requires, and prior Commission orders have allowed, a return on Job Development Investment Tax Credits (JDITC) at the rate of return for permanent capital, so the associated returns for JDITC-Debt and JDITC-Equity reflect the corresponding permanent capital rates of 4.24% and 10.5%, respectively. Deferred income taxes are at zero cost (Vangilder, 6T 2814, 2816; Exhibit A-14, Schedule D1, lines 6, 7, and 9).

E. Overall Rate of Return

The sum of the weighted cost of the above-described capital components results in a weighted, after-tax 5.92% overall rate of return (Vangilder, 6T 2812; Exhibit A-14, Schedule D1, line 10, column (g)). A 1.3496 revenue conversion factor is appropriate for the projected period (Vangilder, 6T 2813; Exhibit A-13, Schedule C2). The corresponding weighted pre-tax overall rate of return is 7.37% (Exhibit A-14, Schedule D1, line 10, column (i)). DTE Electric supports the use

of the 5.92% overall rate of return in the derivation of its revenue requirements and the use of the 7.37% pre-tax overall rate for the return on rate base.

VII. ADJUSTED NET OPERATING INCOME AND REVENUE DEFICIENCY[95]

DTE Electric's Total Electric Adjusted Net Operating Income (NOI) was $1,132.0 million in the 2022 historical test year and was projected to be $1,087.1 million in the 2025 projected test year (Uzenski, 6T 1510; Exhibit A-13, Schedule C1, line 17). DTE Electric's operating income is projected to increase due to higher revenues from new base rates in Case No. U-21297, effective late December 2023. The increase in revenues is partially offset by increased O&M, depreciation and property taxes related to capital additions, and increased income taxes (Uzenski, 6T 1508). After reviewing Staff's and other intervenors' positions and the full record in this case, the Company agrees to adopt certain adjustments and update its projected test year NOI to approximately $1,092 million. (Attachment A, page 3 of 4).

A. Sales Forecast

DTE Electric's forecasting methodology to determine future sales reflects widely-accepted industry standards for electricity forecasting, is continuously checked for accuracy, and has provided reasonable forecasts that are on par with peer utilities (Leuker, 6T 1775, 1796-99). On average, for historical years 2018 through 2022, the absolute percent variance for the Company's total sales forecast is 1.87% (Leuker, 6T 1796; Exhibit A-15, Schedule E5, page 1). There was some

[95] See generally supra, Section II. History of Proceedings – *DTE Electric* - Uzenski, Leuker, Bellini, Willis, Hooper, Fix, Foley, Guillaumin, Milo, Davis, Kryscynski, Steudle, Lepczyk, Vangilder, Hatsios, Bennett, Sparks, Wisniewski; *Attorney General* – Coppola; *ABATE* – York; *Staff* – Rueckert, McMillan-Sepkoski; *AG-MN* -- Alvarez; *DAAO* – Koeppel; *MI-MAUI* -- Bunch; *Ann Arbor* – Giacobazzi; *CUB-MEC* – Bandyk, Denzler

deviation due to the COVID-19 pandemic.[96] Excluding 2020 and 2021, the average absolute percentage variance in the Company's forecast is 0.94%, representing 99.1% accuracy. The Company achieved an absolute variance of 0.5% in 2022 (99.5%) accurate), and was on track to achieve 0.76% in 2023 (99.2% accurate, based on 10 months of historical data). (Leuker, 6T 1796-98; Exhibit A-15, Schedule E5, page 1). DTE Electric is also on par with peer utilities across the nation in forecasting by customer class and peak demand (Leuker, 6T 1798-99; Exhibit A-15, Schedule E5, page 2).

The Company's forecasting methodology is generally the same as it was in Case No. U-21297, with updated data. The forecast is developed separately for each of the major customer classifications (Residential, Small C&I, Large C&I, and Other). Residential class sales were forecast using a Statistically Adjusted End-Use (SAE) model, which specifies energy use as a function of 22 end uses, including EV and DG demand, along with factors that affect the end-use requirements such as economic activity and weather. Small C&I class sales were similarly forecasted using an SAE model, utilizing 11 end-uses including DG and EV demand. Large C&I class sales were forecast using econometric models for seven supersector markets, and post-regression adjustments to account for matters not captured by regression modeling, which are mainly including EV growth, and large customer projects that are informed by customer account managers (Leuker, 6T 1775-88). Mr. Bellini provided the Other (street lighting) forecast (Bellini, 6T 3107-3109).

For the projected test period, service area sales are projected to be 44,189 GWh, and bundled sales are projected to be 39,756 GWh (Leuker, 6T 1798; Exhibit A-15, Schedule E1, pages 1

[96] For example, the 2021 forecast was completed when case counts began to stabilize, just prior to the sharp spike in cases caused by the Delta variant. This and the subsequent waves in 2021 caused more business closures, as well as continued work-from-home policies, ultimately creating sustained sales variances through 2021 that were contrary to what the trends in the data indicated when the forecast was completed (Leuker, 6T 1797).

through 3). Service area system output and annual peak demand are projected to be 47,341 GWh and 10,911 MW, respectively. Bundled system output and annual peak demand are projected to be 42,683 GWh and 10,157 MW, respectively (Leuker, 6T 1795; Exhibit A-15, Schedule E2, pages 1 and 2).

Mr. Leuker further explained that service area sales are expected to decrease to 44,170 GWh in 2028. This represents a -0.4% compound annual growth rate (CAGR). Bundled sales are expected to decline to 39,786 GWh in 2028. This represents a -0.3% CAGR (6T 1789).[97]

No party presented contrary or alternative testimony. Therefore, the Commission should adopt Mr. Leuker's well-supported and undisputed sales projections.

B. Fuel and Purchased Power Revenue and Expense

DTE Electric proposes to maintain the current Power Supply Cost Recovery (PSCR) base of 31.26 mills per kilowatt-hour at the generation level, which the Commission established in its December 23, 2008 Opinion and Order in Case No. U-15244, and maintained in subsequent cases. The Company proposes to update the loss factor, however, which will result in a PSCR base of 33.66 mills per kilowatt-hour at the sales level as reflected on Exhibit A-13, Schedule C-4. The 7.69% loss factor is the average difference between annual system output and sales over the last five years (2018 through 2022) as shown on Exhibit A-13, Schedule C4.1, which is the method that

[97] DTE Electric's service area Residential class sales are projected to decline 0.3% annually, on average, between 2023 and the 2025 projected test year. DTE Electric's service area Small C&I class sales are forecast to decrease 0.3% annually, on average, between 2022 and 2025. DTE Electric's service area Large C&I class sales are projected to decrease by 0.7% annually, on average, from 2022 to 2025. DTE Electric's service area Other Class (which consists of street lighting and traffic signals) sales are projected to decline by 1.5% annually, on average, from 2022 through 2028, mainly due to the use of more efficient lighting (Leuker, 6T 1790-94). Choice sales are projected to decrease to 4,383 GWh in 2028, which represents a -0.4% CAGR (Leuker, 6T 1790).

DTE Electric's temperature-normalized service area system peak demand is projected to decline from 10,959 MW in 2022 to 10,905 MW in 2028, representing a CAGR of -0.1%. DTE Electric's bundled peak demand is projected to decline from 10,207 MW in 2022 to 10,151 MW in 2028, representing a CAGR of -0.1% (Leuker, 6T 1795-96; Exhibit A-15, Schedule E2, pages 1 and 2).

the Commission approved in Case No. U-21297. The Company does not project any PSCR over or under-recovery in this case. The Company's proposed rates reflect the 33.66 base, and the Company used a zero PSCR factor to calculate revenues for the projected period. (Willis, 6T 2583-84).

In light of the above explanations, the Company's proposed PSCR loss factor recommendations should be adopted.

C. Operating and Maintenance (O&M) Expenses

DTE Electric had $1,224.4 million of adjusted O&M in 2022, which was projected to increase to $1,267.0 million in the projected test year (Uzenski, 6T 1497; Exhibit A-13, Schedule C5, line 12, columns (f) and (l)). The Company's projected O&M has been adjusted by a $3.8 million reduction to Uncollectible Expense, a $1.2 million reduction for the amortization of deferred incentive compensation, and a $0.1 million reduction to the amortization of deferred ACPP and TOD costs resulting in $1,261.8 million. (See Attachment A, page 3 of 4).

1. Inflation

Company witness Uzenski calculated inflation rates of 3.2% for 2023, 2.9% for 2024, and 2.9% for 2025, as shown on Exhibit A-13, Schedule C5.15, line 15. These are composite rates using a 3.0% inflation rate for labor, and the consumer price index (CPI)-Urban for non-labor costs. (Uzenski, 6T 1497). Company witness Fix further explained that he conservatively estimated annual wage increases of 3.0% for 2023, 2024, and 2025, based largely on mandatory base pay increases and progression increases set forth in the Company's collective bargaining agreements with labor unions representing DTE Electric employees (Fix, 6T 2866-67).

AG witness Coppola asserted that "[t]he use of a 'blended rate' inclusive of wage increases has been rejected in recent general rate cases and the Commission should do so again in this rate

case. Instead, the Commission has previously adopted use of the CPI-Urban area inflation rates to forecast future cost increases when warranted" (Coppola, 6T 3685).

Witness Coppola neglected that the Commission previously adopted the Company's proposed composite inflation rates (November 18, 2022 Order in Case No. U-20836, p 258. See also December 1, 2023 Order in Case No. U-21297, p 193). The use of a composite rate continues to best reflect the inflationary pressures faced by the Company, since the Company's labor costs are subject to Company-specific dynamics like collective bargaining agreements with unionized employees (Foley, 2T 174). Mr. Fix further explained:

> Based on existing Collective Bargaining Agreements, the Company is obligated to increase base pay rates by at least 3.0% annually through the term of the contracts. In addition to scheduled pay rate increases, the agreements also provide for progression increases for those employees that have not yet achieved the maximum pay rate for their positions. [Fix, 6T 2866.]

DTE Electric also conducts reviews for employees who are not covered by collective bargaining agreements. Pursuant to these reviews, the Company implemented base pay adjustments in 2023 that resulted in an overall pay increase of 3.0%, which was comparable to annual pay increases in every year since 2010. Employees also receive pay increases based on promotions (Fix, 6T 2866-67).

There is no evidence that DTE Electric can avoid paying wage increases as set forth above, and any proposal that DTE Electric should do so neglects that DTE Electric cannot violate its Collective Bargaining Agreements, and the Commission has no authority to become involved in or dictate results of collective bargaining.

The Company further notes that AG witness Coppola's recommended use of the CPI-Urban rate is similar to the CPI-Urban rate proposed by the Company for escalating non-labor costs. The only difference is the source of the rate (the Company used the rate published by S&P/IHS, which was approved in past cases; Witness Coppola used the rate published in the "Blue Chip Report").

Witness Coppola did not provide any evidence to support this change, and it appears that the rate (indicated in Exhibit AG-2) only reflects the first half of 2025, which is inappropriate because the projected test year consists of all of 2025 (Foley, 2T 175).

ABATE witness York similarly opposed the blended rate, and instead recommended projected inflation rates based on the Real GDP Chained Price Index, asserting:

> Each year, the basket of goods and services is updated to reflect what people are actually buying. This is unlike the CPI, which uses a fixed basket for a set period. This makes the Real GDP Index more responsive to consumer substitution – if prices of certain goods rise, people might switch to less expensive alternatives, and the index will reflect that change. In addition, the CPI can be heavily weighted by the cost of medical expenses, which is not reflective of the cost of utility expense. [York, 6T 3342.]

The Company disagrees with ABATE's proposed use of the Real GDP Chained Price Index because there is no compelling evidence that it is superior to the CPI-Urban in projecting *utility-specific* non-labor costs. For example, witness York discusses "customer substitution" in the quote above, but it is anything but apparent how this would even be relevant for utility costs, particularly considering a utility's potentially limited ability for substitution in this context. The CPI-Urban is also a well-established and widely-used measure of inflation. Therefore, ABATE's latest inflation alternative (the third different method in the last three cases, Case Nos. U-20836, U-21297, and U-21534) should be rejected (Foley, 2T 175-76).

CUB/MEC witness Bandyk did not directly contest the Company's proposed inflation rates, but instead suggested that both labor and non-labor rates should be reduced by certain factors to account for potential productivity gains, based on assertions that "DTE does not face the competitive pressures to improve productivity that can be found in non-regulated industries," and that reducing inflation to account for productivity gains "would simulate the effect of productivity improvements on DTE's costs" (Bandyk, 6T 3741-42).

The Company disagrees because its Continuous Improvement (CI) program strives to identify and execute sustainable productivity improvements and leverage new technology to reduce costs. Any known and measurable cost reductions related to productivity gains are already embedded in each business unit's financial exhibits. CUB/MEC's proposed additional productivity adjustment would "double count" productivity improvements. CUB/MEC's proposal is also inconsistent with the "known and measurable" nature of rate case projections (Foley, 2T 177-78. See also section IV regarding the Test Year).

Therefore, the Commission should approve DTE Electric's proposed composite inflation rate, and reject alternative and additional proposals.

2. Energy Supply (Exhibit A-13, Schedule C5, lines 1, 4 and 5; Schedules C5.1, C5.4 and C5.5)

DTE Electric's actual and forecast Energy Supply O&M expenses consist of three major categories: (1) Steam Power Generation, (2) Hydraulic Power Generation, and (3) Other Power Generation, as shown on Exhibit A-13, Schedules C5.1, C5.4, and C5.5. Company witness Guillaumin explained the major line items and adjustments (6T 1708-16). Steam Power Generation adjusted O&M (*excluding* Fuel Supply and MERC fuel handling as described below) was $223.2 million in 2022, and is projected to be $213.4 million in the projected test year (Exhibit A-13, Schedule C5.1, page 1, line 21, columns (g) and (m)). Hydraulic Power Generation adjusted O&M was $10.3 million in 2022, and is projected to be $11.2 million in the projected test year (Exhibit A-13, Schedule C5.4, line 17, columns (e) and (k)). Other Power Generation adjusted O&M was $22.9 million in 2022, and is projected to be $31.5 million in the projected test year (Exhibit A-13, Schedule C5.5, line 18, columns (e) and (k)). Based on these facts and as further detailed on the record, the Company's Energy Supply historical and projected O&M expenses are reasonable and prudent, and therefore should be recovered (Guillaumin, 6T 1716).

3. Midwest Energy Resources Company (MERC) and Fuel Supply (Exhibit A-13, Schedule C5, line 2; Schedule C5.2)

Midwest Energy Resources Company (MERC) and Fuel Supply O&M expense was $8.3 million in 2022, and is projected to be $8.1 million in the projected test year (Milo, 6T 1752, 1764-66; Exhibit A-13, Schedule C5.2, line 16, columns (f) and (l)). Mr. Milo explained the nature of the O&M expenses for the projected test year, and that they were based on the adjusted historical 2022 expenses adjusted for inflation ($4.9 million for Fuel Supply and $3.2 million for MERC, as shown on Exhibit A-13, Schedule C5.2, column (l), lines 7 and 15). There was an almost $1 million adjustment (23% reduction) for MERC fuel handling as a result of expected savings and avoided costs from decreased transshipment activities. As with MERC capital expenditures, these O&M expenses reflect the minimum expense required to operate the facility safely, reliably and in an environmentally-compliant manner, which helps ensure that critical coal deliveries are made to the Company's power plants as they continue to operate during the Company's transition from coal-fired generation (Milo, 6T 1765-66).

4. Nuclear Power (Exhibit A-13, Schedule C5, line 3; Schedule C5.3)

Company witness Davis supported Fermi 2's 2022 actual, as well as projected, nuclear O&M expenses through December 31, 2025 (6T 1805). Actual O&M expenses for 2022 were $220.3 million (Davis, 6T 1855; Exhibit A-13, Schedule C5.3, page 1, line 24, column (c)). Two adjustments are necessary. First, column (d) reflects a $28.6 million reduction because costs associated with site security (security and radiation protection services) were removed from base rates and recognized in the Nuclear Surcharge in Case No. U-14399. Second, column (e) reclassifies Program Evaluation Review Committee (PERC) project expenditures to make explicit that the $15.1 million PERC Base Expense and the $16.3 million PERC Regulatory Asset amortization are not inflated in the projected adjustments (Davis, 6T 1855-56). Adjusted O&M

expenses for 2022 were $191.8 million (Exhibit A-13, Schedule C5.3, page 1, column (g), line 24), and were used to forecast projected O&M expenses through December 31, 2025. Mr. Davis explained various O&M expenses and adjustments, and testified that $159.4 million of O&M will be required to support the safe and reliable operation of Fermi 2 in the projected period, which is prudent and reasonable (Davis, 6T 1855-56, 1877; Exhibit A-13, Schedule C5.3, page 1, line 24, column (n)).

The total PERC expense for the projected test period is forecasted at $19.9 million (Exhibit A-13, Schedule C5.3, column (n), line 23). PERC expenses over or under $15.0 million are deferred. The Company spent $18.1 million on PERC projects in 2022, and expects to spend $8.9 million in 2023, $22.6 million in 2024, and $8.6 in 2025 (Exhibit A-13, Schedule C5.16). Exhibit A-13, Schedule C5.17 shows the derivation of the PERC amortization (Davis, 6T 1866-67). Mr. Davis also explained and supported various projects as reasonable and prudent, and that they should be approved because they are required for Fermi 2's safe operation for the projected test year (Davis, 6T 1868-77).

5. Distribution (Exhibit A-13, Schedule C5, line 6; Schedule C5.6)

Distribution Operations' O&M expenses are driven primarily by day-to-day trouble and storm restoration, tree-trim work, and other system maintenance requirements. The Company projects $359.2 million of O&M expenses for the projected test year (Kryscynski, 3T 317-18; Exhibit A-13, Schedule C5.6, p 1, line 27, column (l)). The forecast is based on actual 2022 O&M expenses, normalized and adjusted. Company witness Kryscynski explained and justified significant components and adjustments underlying the projected O&M costs, as reflected on Exhibit A-13, Schedule C5.6, and supported the actual and projected O&M costs as reasonable and prudent (3T 318-22).

These O&M expenses include $64.5 million of storm restoration O&M expenses, which were calculated based on a five-year trailing average (historical test year and preceding four years) adjusted for inflation, which is consistent with past cases (Foley, 2T 128-29; Kryscynski, 3T 321; Exhibit A-13, Schedule C5.6, page 2, lines 1-8). The current approach to storm restoration O&M expense recovery puts both customers at risk of an over-recovery, and the Company at risk of an under-recovery, because it does not address the uncertainty and variability of those expenses in any given year. To address this issue, the Company proposes that the Commission authorize a Storm Restoration Cost Sharing Mechanism (SRCSM), as discussed in section VIII. B.

The Company seeks base tree trimming O&M funding of $109 million for 2025. The Company is also seeking additional surge funding of $110 million, which consists of a request for approval of an incremental regulatory asset in 2025 ($87 million) and increasing the base O&M in 2026 ($23 million over the Case No. U-20162 forecast). (Steudle, 6T 2982-83).

Recounting briefly for context, Michigan's 2013 ice storm left tens of thousands of customers without power and demonstrated that historic tree trimming practices were insufficient. The Commission recognized that trees are the primary cause of power outages, and that DTE Electric was fully spending its allocated funding for vegetation management to prevent such outages (May 2, 2014 Order in Case No. U-17542, p. 16; December 4, 2014 Order in Case No. U-17542, pp. 4-5). Therefore, DTE Electric began investing in a new Enhanced Vegetation Management Program (EVMP, now re-named the Enhanced Tree Trimming Program or ETTP), which essentially trims vegetation in a clearance corridor rather than the historic clearance circle around DTE Electric's lines and equipment. The Commission approved the ETTP in Case No. U-17767, and increased funding to clear more miles of lines in Case No. U-18014. In Case No. U-18255, the Commission again approved increased ETTP funding, emphasizing the importance of expenditures to improve the distribution system's safety and reliability (April 18, 2018 Order in

Case No. U-18255, pp. 43-44). In Case No. U-20162, the Commission again recognized the importance of tree trimming, and approved DTE Electric's seven-year surge proposal, in part (May 2, 2019 Order in Case No. U-20162, pp. 79-80). In Case No. U-20561, the Commission "reiterate[d] its desire for a safe and reliable electric system" and "approve[d] the $58.2 million requested surge funding for 2022" (May 8, 2020 Order in Case No. U-20561, pp. 208-209). In Case No. U-20836, tree trimming expense was uncontested, and the Commission "approve[d] DTE Electric's $103.9 million base O&M for tree trimming and the company's requested $67 million and $52.7 million in surge funding for the years 2023 and 2024, respectively" (November 18, 2022 Order in Case No. U-20836, p 261). Most recently, the Commission approved an additional $43.7 million of surge funding for 2025 (December 1, 2023 Order in Case No. U-21297, p 280).

Against this background, Company witness Steudle testified that DTE Electric trimmed 5,299 line miles in 2023, bringing the system to 83% on-cycle.[98] The Company projects that approximately 90% of circuit miles will be on-cycle at the end of 2024. In Case No. U-20162, the Company proposed trimming the full system to the ETTP specification and maintaining a five-year cycle (three-year cycle for subtransmission) by the end of 2025. The Company expects to have 10% of its system to reclaim[99] in 2025, with the continuing goal to be 100% on-cycle by the end of 2025 (Steudle, 6T 2965-66, 2974, 3024). [100]

The ETTP is a well-designed program with proven success and continuing importance. Circuits trimmed as part of the ETTP have a 54.0% reduction in outage events in the year after

[98] On-cycle means that the circuit miles have been trimmed to the ETTP specification at least once, and are on a maintenance trimming cycle for future years (Steudle, 6T 2966).

[99] Reclaim miles are circuits that have not been trimmed to the ETTP specification, and are considered off-cycle (Steudle, 6T 2966).

[100] Thus, there is no basis for insinuations that the Company neglects its tree trimming efforts (e.g., Ann Arbor witness Stults, 6T 4262; AG-MN witness Alvarez, 6T 3956). Moreover, in addition to the Company's system being 83% on-cycle at the end of 2023, Ann Arbor was 95% on cycle (Steudle, 6T 3024).

trimming compared to non-ETTP trimmed circuits. ETTP-trimmed circuits similarly showed reductions of 57.9% in customer interruptions, 32.4% in the number of customer minutes of interruption, and 55.4% in wire-down events in the year following trimming, compared to non-ETTP circuits (Steudle, 6T 2968-72).[101]

The surge program needs to continue because, as discussed in the Company's Grid Distribution Plan in Case No. U-20147, tree interference remains one of the leading drivers of customer outages. Historically, tree-caused outages accounted for two-thirds of the time that customers spend without power (Steudle, 6T 2964).

The Company recently identified a funding gap to complete all reclaim miles and maintain on-cycle miles at the intended five-year cycle. The Company now estimates that the full cost of the surge will be $1,383.2 million, which is $251.2 million more than originally forecasted in Case No. U-20162. The largest driver of the variance is the cost of on-cycle work (distribution miles trimmed to the ETTP specification and due for their next trim) being $133.6 million higher than originally projected. The cost change emerged recently, as the first circuits trimmed to the ETTP specification began returning for their first on-cycle trims (Steudle, 6T 2975-76).

Ms. Steudle explained that the Company's surge cost forecast in Case No. U-20162 assumed that once circuits were on cycle there would be a 40% cost savings, based on a work study by ECI, a third-party consultant. Actual costs for reclaim miles have totaled $28 million less than the forecasted cost, but actual costs for on-cycle miles have totaled $162 million more than forecasted, for a net increase of $134 million more than the surge model forecast. The variance in on-cycle

[101] Despite this success, tree trimming alone is not enough to improve reliability, as some witnesses seem to suggest (e.g. AG/MEC/NRDC witness Alvarez, 6T 3930-31). The Company must take a holistic, multipronged approach to achieve its reliability goals and ensure safe, reliable service to customers. Tree trimming is an important piece, but the Company also must make strategic capital investments to address the age and condition of its equipment (Steudle, 6T 3024-25).

savings is driven by actual experience being different than ECI's assumptions regarding work location (percentage of backlot work) and tree removal rates (ECI assumed that 100% of good removal candidates would be removed). (Steudle, 6T 2976-79). Ms. Steudle further explained why ECI's assumptions were notably different than what the Company has actually experienced:

> ECI sampled the territory to identify total trees, good removal candidates, and work location. For removal rates, ECI assumed all trees identified as good removals would be removed during the first trimming to the ETTP specification. Customer approval is required for all removals on property. This would have meant the Company had 100% acceptance by customers to remove all these trees. At the time of study, the ETTP specification was relatively new, and the Company had limited data to understand the customer approval rate with respect to removals.
>
> For front vs. back lot, ECI identified trees as accessible or inaccessible. This was done by surveyors who determined whether the tree could be addressed by a bucket truck or other mechanized equipment. Accessibility of equipment is dependent on physical ability to maneuver equipment to the tree, but also customer willingness to allow the equipment on their property, soil condition, weather and other factors. [Steudle, 6T 2978-79.]

The presently estimated surge cost as compared to the Case No. U-20162 forecast also includes an increased outsource premium of $69.7 million. To complete the volume of trimming needed in the surge, the Company recognized the need to pay a premium (per diems and crew overtime) to attract outsource crews to work in the Company's service territory. Actual costs have exceeded the forecast cost because the Company required approximately 100 more outsource trimmers annually to supplement the local workforce (Steudle, 6T 2976, 2979-80).

There are also two programmatic additions to the surge program (spot trimming[102] and the Detroit Tree Trim Academy) that were not included in the Case No. U-20162 forecasts, which total $30.5 million (Steudle, 2976, 2980).

[102] Spot trimming involves targeted trimming on poor performing circuits that have a high number of sustained and/or momentary outages (Steudle, 6T 2974, 2980).

The final item of additional cost is $17.4 million for inflation because the surge model assumed an annual inflation rate of 3%, but actual costs have been driven by the labor rates negotiated between IBEW Local 17 and tree trim contractors. The annual labor increase for line clearance tree trim contracts ranges from 4% to 6% through the life of the surge. The difference is $13.6 million. Also, the surge model assumed that base O&M would increase each year through annual rate cases, but the Company deferred filing a rate case for two years, which caused the Company to forego $3.8 million in inflation-related increases in base O&M (Steudle, 6T 2976, 2980-81).

The Company largely addressed the cost variance by utilizing extra revenues that were collected due to altered electric sales patterns during the COVID-19 pandemic to fund additional surge investments, without impacting rates (Steudle, 6T2981-82. See also, the November 4, 2021 Order in Case Nos. U-21128 and U-20162). Most recently, the Commission approved the Company's request to net the remaining balance of the regulatory liability established under the November 4, 2021 Order ($600,460) against the deferred tree trim cost regulatory asset, as more effective than issuing a bill credit to customers.

The Company proposes to address the remaining $110 million of funding needed through a combination of incremental regulatory asset in 2025 ($87 million) and increasing the base O&M in 2026 ($23 million over the amount forecasted in Case No. U-20162). (Foley, 2T 93-94; Steudle, 6T 2982-83, 2986-87).

AG witness Coppola objected to including the additional $87 million in the regulatory asset for a number of reasons (Coppola, 6T 3649-53). The Company disagrees. In addition to the discussion above, the objections lack merit as discussed below.

Witness Coppola first suggested that "[t]he $1.4 billion spent on tree trimming from 2019 to 2025 is significantly understated [because it] includes only O&M costs and deferred costs under

the surge program [and not] the additional $496 million spent on tree trimming as part of capital programs when electrical lines and related facilities are replaced or upgraded, which also helps with managing tree growth and avoiding future power outages" (Coppola, 6T 3650). The Company disagrees with the AG's suggestion that the Company mischaracterized the investment in the surge. The referenced $496 million is part of emergent capital expense (Exhibit A-22, line 27), which mostly reflects the cost of linemen and field personnel to restore outages caused by trees. Those dollars are not associated with trimming trees. Also, capitalized tree trimming costs have appropriately never been included in the surge program. Tree trimming that is capitalized is performed to support construction projects (Steudle, 6T 3010-11). See also the December 1, 2023 Order in Case No. U-21297, p 281, and section VIII. F. 1 (Tree Trimming Capitalization).

Witness Coppola next suggested that the Company has not demonstrated that the surge is effective (Coppola, 6T 3651-52). To the contrary and as discussed in part above, Ms. Steudle's direct testimony includes an entire section demonstrating that circuits trimmed to the ETTP specification experience a significant improvement in reliability compared to circuits that are off-cycle and not trimmed as part of the surge program (Steudle, 6T 2967-72, 3009).

Witness Coppola asserted that the severe storms in 2023 provided an opportunity to gauge whether the tree trim surge was effective, and concluded in his opinion that it has not. (Coppola, 6T 3651-52). The Company disagrees with the suggested use of 2023 as the test for the surge's effectiveness. Ms. Steudle explained in part:

> When the Company measures the effectiveness of the Tree Trim program, weather is normalized to account for variability in year-to-year events. This annual variability was exacerbated in 2023 when the Company experienced five catastrophic storms, including the most damaging winter ice storm in Company history, and another summer catastrophic storm event that included heavy damage from a historic six tornados.
>
> The 2023 winter ice storm was especially challenging from a tree damage perspective. The ice was almost ¾ inches thick in many areas and the weight of the

> ice severely damaged trees, wires, equipment, and poles. This type of weather phenomena caused significant damage to healthy trees that would not fail under typical weather events. [Steudle, 6T 3009-10. See also, Hill, 6T 3036-3041).

Witness Coppola next asserted that, based on an increase in cost-per-mile for reclaiming circuits, "the Company should have had indications as early as 2022 that tree clearing costs were escalating significantly and could have taken corrective action " (Coppola, 6T 3652). The Company disagrees because the average cost per mile can vary year-to-year based on the volume of work required by the unique vegetation characteristics of each circuit. Ms. Steudle explained that 2022 was an outlier so Mr. Coppola's reliance on 2022 data was misplaced:

> In 2022, the cost of reclaim miles was high because of the areas in which we focused our trimming. In 2022, the Company prioritized several key communities that were significantly off-cycle compared to our system average. These communities were also ones significantly impacted for the 2021 weather events and the Company recognized the need to focus reclaiming these areas to improve reliability for these impacted customers.
>
> The tree work in these areas was more dense and intensive, therefore expensive than in past years and drove up the overall average for 2022. The average cost for reclaim circuits reduced by 20% in 2023, validating that 2022 was an outlier. [Steudle, 6T 3011-12.]

Witness Coppola next took issue with the Company's payment of premiums to attract and retain outsource tree trimming crews (Coppola, 6T 3652-53). The Company disagrees because it was necessary to quickly ramp up trimming resources by supplementing the local workforce with outsource trimmers when the surge was approved. The workforce has also been in high demand across the country because many utilities are increasing their vegetation management programs. The Company has appropriately paid a competitive per diem to retain the necessary workforce for the surge. The Company has also appropriately offered 60-hour work weeks for maintenance trimming (20 hours of overtime), which is attractive to outsource trimmers because they are interested in maximizing the work week while in this area (Steudle, 6T 3013).

The Company anticipated the need to ramp up the tree trimming workforce and that it would need to pay outsource premiums in Case No. U-20162. The Company now anticipates paying $69 million more in outsource premiums than forecasted in Case No. U-20162 for the full length of the surge. Actual costs have exceeded the original forecast because the Company has required more outsource trimmers than anticipated. This is primarily due to the local workforce not growing at the expected rate due to the disruption caused by the COVID-19 pandemic. Many workforce development efforts were paused in 2020, creating a hole in the woodsmen pipeline. The dynamic of the job market also shifted coming out of the pandemic (Steudle, 6T 3013-14).

Witness Coppola further asserted that "[t]he latest forecast is an alarming 153% increase in additional costs paid to a handful of contractors. The Company needs to take corrective steps to significantly mitigate or eliminate these extra costs for 2024 and 2025" (Coppola, 6T 3653). The Company disagrees. Although costs have increased, there are good reasons for the increase as outlined above, so there is no cause for "alarm." The Company also disagrees with the suggestion that it should take "corrective steps" against the Company's current four contractors. The amount of outsource premiums is driven by the number of outsource trimmers that the Company has on property,[103] not the number of contractors. The Company has had an average of 390 outsource trimmers on property to support the surge. The per diem is a direct pass through to the outsource trimmers, and the overtime premium reflects the Local-17 wage structure that the Company pays all tree trimmers. The Company will continue to look for ways to reduce costs, but Mr. Coppola's suggestion to stop paying premiums should be rejected because it would significantly jeopardize the completion of the surge (Steudle, 6T 3014-15).

[103] With respect to the tree trimming workforce, "on property" means a full-time equivalent largely dedicated to work on the Company's behalf (Steudle, 6T 3014, n 2).

The Company is also participating in three programs to increase the number of local tree trimmers: (1) the IBEW Local 17 Traditional Boot Camp, (2) the Parnell Correctional Facility Vocational Village training program, and (3) the City of Detroit Tree Trim Academy (Steudle, 6T 3015-16). AG witness Coppola took issue with the Company's investment in the Detroit Tree Trim Academy, claiming that it has "a retention rate of 33%," which "cannot be considered a success," so he recommended that "[t]he Company should look at either significantly restructuring the program to at least double the retention rate or, if that goal is not achievable, shut down the academy and reassign those dollars to hiring trained tree trimmers or not spend them at all" (Coppola, 6T 3653).

The Company disagrees because Mr. Coppola miscalculated the program's retention rate as 33%. Since 2021, 56% of the students who have been placed with a tree contractor continue to work as tree trimmers on property. This is a success because, historically, only 30% of trimmers who began the traditional bootcamp successfully progressed through full apprenticeship. Academy graduates who were placed on property are almost twice as likely to continue through the apprenticeship. The Academy also provides additional benefits of increasing diversity in the tree trimming workforce and providing career opportunities to the local community. The Company plans to continue with an annual investment of approximately $700,000 in 2025, with a total of $4.3 million for 2019 through 2025 (Steudle, 6T 3016-18).[104]

In addition to trimming trees, the Company also targets removing some trees within its right-of-way. AG witness Coppola raised a concern that the Company's annual removal rate was "only between 38% and 48%" of the trees that the Company planned to remove (Coppola, 6T 3654). The

[104] AG witness Coppola misstated the planned investment, arguing against "the *additional* $4.1 million that the Company wants to allocate to it in 2025" (Coppola, 6T 3653. Emphasis in original).

Company has not removed more trees because a customer must provide signed permission to remove a tree. The pushback from some customers can be significant (Steudle, 6T 3018).

Thus, AG witness Coppola's criticisms and proposals all lack merit. The requested $87 million is a prudent and justified request that is essential to both complete the surge and keep on-cycle miles trimmed and maintained.[105] The Company also performed extensive analysis to understand the drivers for the gap in funding, and closed the majority of the shortfall without requesting incremental support (Steudle, 6T 3019).

The Company proposes to defer surge costs up to $183.4 million above base rates from 2024 through 2025. The Commission previously approved regulatory asset treatment for the incremental costs of tree trimming above base rates through 2024 totaling $365.8 million. Of that amount, $156.9 million (2019 through June 30, 2021) was securitized pursuant to the June 23, 2021 Order in Case No. U-21015. Securitization remains appropriate to recognize the long-term nature of the program. Recovery over a longer period provides a better matching of costs with anticipated savings, minimizing the cost impact to customers (Foley, 2T 94-95; Steudle, 6T 2983-84).

A securitization filing capturing costs through early 2025 is technically feasible in 2025, but due to the fixed costs of securitizing and the remaining time before the conclusion of the surge, DTE Electric is planning to file a final tree-trim related securitization after the surge program concludes in 2025, capturing all expenditures not previously securitized (Foley, 2T 95-96).

In Case No. U-20162, the Commission authorized a return on the tree trim regulatory asset at the Company's short-term debt rate, reasoning that the regulatory asset treatment of surge costs

[105] If the Commission does not approve the additional $87 million of regulatory asset funding, then one of the following scenarios would likely occur in 2025: (1) Prioritize reclaim miles with available funding to complete the surge, which would limit the Company's ability to maintain approximately 3,200 on-cycle miles (causing future trimming expense to increase and impacting reliability); or (2) Prioritize maintaining miles due for on-cycle trimming, which would result in approximately 1,900 reclaim miles not being trimmed in 2025 (also impacting reliability). (Steudle, 6T 2984-85).

was temporary in light of the Company's contemplated securitization filing (May 2, 2019 Order in Case No. U-20162, p. 80). [106] This treatment was continued in subsequent cases, where most recently in Case No. U-21297, the Company calculated a return based on the short-term interest rate to reduce the number of contested issues, but maintained that this was inappropriate. For example, in securitization Case Nos. U-21015 and U-21338, the Commission considered the regulatory asset to have been financed with permanent capital, and specified that proceeds of the securitization should be used for the repayment of long-term debt and equity. The Company acknowledges that others disagree (AG-MN witness Alvarez, 6T 3955; Staff witness Rueckert, 6T 4990-91), but respectfully maintains that any future tree-trim surge regulatory asset amounts should be treated as being financed with permanent long-term debt and equity, and receive the respective return. Exhibit A-11, Schedule A1.1 identifies the $18.8 million return on the tree trim surge regulatory asset for the projected test period using that methodology (Foley, 2T 95; Lepczyk, 6T 2559-60, 2565-66; Vangilder, 6T 2817).

Assuming that the Company completes all reclaim miles by the end of 2025, then the "post-surge" period will begin in 2026. The Company forecasts that the post-surge tree trimming program will require approximately $135 million per year (not adjusted for inflation) to maintain the surge's investment and keep all miles on-cycle. This forecast assumes cost savings from the use of a risk-based variable cycle (Steudle, 6T 2986-87, 2991).

Ms. Steudle explained that the Company recognizes that there are opportunities to adjust the target cycle for different parts of the system using technology such as LiDAR (light detection

[106] Securitization is the financing of a discrete asset or group of assets by a utility with securities whose credit quality is separated from that of the utility, in order to achieve higher credit ratings and lower financing costs.

and ranging),[107] which has emerged as a valuable tool for vegetation management. The Company believes that adjusting cycle-lengths based on tree species' growth rates, risk of outages, and cost of trimming will further improve trimming efficiencies and provide reliability benefits to customers. The Company developed a risk-based, variable cycle model that leverages remote sensing date (e.g., LiDAR), advanced analytics, and machine learning to estimate the probability of vegetation-driven failures, and determine optimal trim cycles for an area. The model will also provide key improvements to the Company's annual planning and execution of its maintenance plan. The Company anticipates that risk-based cycles will yield a minimum of 5% savings annually during the initial transition to variable cycles. In this case, the Company seeks to recover an incremental $0.6M above the original $6.3 million investment in the risk prioritization model (as approved in Case No. U-21297) for a total project cost of $6.9M as shown in Exhibit A-12, Schedule B5.4, page 17, line 24 (Steudle, 6T 2987-91, 3006).

AG witness Coppola "recommend[ed] that the Commission remove the $3,078,000 in capital expenditures for 2022 and the $3,824,000 for 2023 pertaining to the Tree Trim Risk Prioritization model because the Company did not perform a cost/benefit analysis and did not justify that the model and related expenditures are economically beneficial to customers" (Coppola, 6T 3656). The Company disagrees because it did perform a cost benefit analysis, which shows a discounted cash flow NPV of $11.2 million (Exhibit A-22, Schedule L2 in Case No. U-21297; Exhibit A-42, Schedule GG2 here). The Company included the capital costs in Case No. U-21297, where they were not disputed by any party nor disallowed by the Commission. The Company already spent the money and is using the model. Moreover, intervenors raised the idea

[107] LiDAR is a remote sensing method that measures the distance to Earth of different objects, such as trees and utility equipment. LiDAR enables the development of a 3D image of an area with accurate measurements between objects and the ground (Steudle, 6T 2988).

of variable cycles in Case No. U-20836, where the Commission directed the Company to evaluate potential benefits from utilizing a variable cycle (November 18, 2022 Order in Case No. U-20836, p 487). The Company complied with that directive by developing the model. Therefore, the AG's proposed disallowance should be rejected (Steudle, 6T 3007-3008).

CUB-MN witness Denzler suggested that the Commission require the Company to perform an audit/review of the Tree Trim Risk Prioritization model to measure its accuracy and compare it to alternative models (6T 3776). The Company disagrees because it has already invested in the current model, which provides benefits to customers. The suggested additional investment would not be prudent. Instead, the Company is prioritizing using and testing the existing model (Steudle, 6T 3022-23).

AG witness Coppola "recommend[ed] that the Commission reduce the Company's forecasted capital expenditures for 2024 and 2025 by $66.9 million and $59.6 million, respectively" based on calculated savings from tree trimming (Coppola, 6T 3616-17). The Company disagrees because it already accounted for tree trimming savings by reducing the requested emergent capital by $20.8 million for 2024, and $21.4 million for 2025 (Steudle, 6T 3001; Exhibit A-12, Schedule B5.4, page 1, line 6).

AG witness Coppola calculated savings based on a response to discovery asking the Company to compare the relative cost savings expected to be realized by executing the surge, versus not executing the surge (Coppola, 6T 3616). The response relied on data presented in Exhibit A-22, which is an output of the Tree Trim Surge model developed for Case No. U-20162 to demonstrate the relative benefit of executing the surge compared to not executing the surge. Exhibit A-22 was last updated for Case No. U-20836 to justify continuing the surge beyond 2021, by comparing continuing the surge in 2022 versus discontinuing it at the end of 2021. Using this Tree Trim Surge model methodology, cost savings would be $22.8 million in 2024, and $30.1

million in 2025 (Steudle, 6T 3002-3003, 3005; Exhibit A-42, Schedule GG1 shows the details of the calculation).[108]

The difference between the AG's projected savings and the Company's projected savings (approximately $11 million) is due to the models using different baselines (the Exhibit A-22 Tree Trim Surge model relied on by witness Coppola used 2018-2020; the Exhibit A-12 Reliability Model relied on by the Company used 2018-2022 to account for more recent actuals). Additionally, the Company's Reliability Model accounted for system degradation, whereas Exhibit A-22 does not. Thus, Exhibit A-12 appropriately accounts for the emergent capital savings arising from the Tree Trim program using the most accurate and current data available, and the AG's proposal for an additional disallowance is unjustified (Steudle, 6T 3004).

AG witness Coppola also recommended that the Commission remove "$8.8 million in additional cost savings from the Company's forecasted O&M expense" due to savings from the surge (Coppola, 6T 3689). The Company disagrees because the savings have already been accounted for. Ms. Steudle explained that the $8.8 million is the net difference of the total calculated O&M savings ($17.6 million) and what was included in Exhibit A-13, Schedule C5.6 ($8.8 million). The $8.8 million difference represents the cost savings for the Tree Trim reactive line item. These costs are included in Exhibit A-22, Schedule L1, line 22 , so the savings between the historical year and the projected test year are already accounted for (Steudle, 6T 3020).

The Commission previously directed the Company to work with Staff to develop a residential service drop tree trimming pilot (December 1, 2023 Order in Case No. U-21297, p

[108] The Company inadvertently provided the wrong data in its discovery response to the AG (Exhibit A-42, Schedule GG3), leading to the AG's miscalculation. The discovery request sought an update to a discovery request from prior rate cases. The Company has submitted a supplemental response with the correct cost savings under the Tree Trim Surge model of continuing the surge compared to terminating the surge at the end of 2021 (Steudle, 6T 3005-3006).

353).[109] The Company is working with Staff and at least one intervenor to develop such a pilot (Steudle, 6T 2993).

Ms. Steudle also explained that the Company divides the overhead electrical system into three zones. In Zone 1 (the portion of the circuit from the substation to the first protective device or drop down),[110] the Company removes all branches overhanging the conductors. In Zone 2 (from the first protective device or drop down to the fused lateral) and Zone 3 (the fused laterals), the Company removes all softwood and hardwood branches overhanging the conductors at less than a forty-five-degree angle. If the Company were to trim Zones 2 and 3 more aggressively, then it would remove all overhang like it does in Zone 1. The Company could perform a pilot to understand the costs and benefits of such a change, but a considerable timeframe would be needed (4-5 years after trimming) to fully measure reliability benefits. Therefore, the Company proposes the alternative of comparing circuits trimmed on the regular maintenance program (control group) to a subset of circuits that have been trimmed with all overhang removed in preparation for construction projects (test group) to understand the impact of potentially changing the trimming specification for Zones 2 and 3 (Steudle, 6T 2994-96).

The Company further notes that there are additional considerations beyond cost and reliability if Zones 2 and 3 were to be trimmed more aggressively, including: (1) anticipated negative customer sentiment because typically the portion of the overhead line that runs through a customer's backyard / property is Zone 2 / Zone 3; (2) the need for more skilled climbing trimmers and specialty trim equipment; and (3) additional growth under wires due to exposing undergrowth

[109] 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 (Steudle, 6T 2992).

[110] A "drop down" is a location on a circuit where a voltage drop or multiple direction split in distribution power takes place (Steudle, 6T 2994, n 6).

and brush to additional sunlight, which could lead to further maintenance costs and interfere with anticipated reliability improvements (Steudle, 6T 2994-97).

AG-MN witness Alvarez recommended that the Commission "order an independent audit of the state of DTE's overhead line rights of way every five years, commencing in 2025 or 2026" (Alvarez, 6T 3922). The Company disagrees because the additional audit would be redundant to existing activities that are more efficient and effective. The Commission previously adopted Staff's recommendations regarding tree-trimming audits (inspections) and an analysis of more aggressive trimming in Zones 2 and 3 (December 1, 2023 Order in Case No. U-21297, p 353). Ms. Steudle explained that the tree trimming program includes auditing (inspections), and explained the nature of those inspections. The Company also supports the continued submission of the Tree Trim annual report, and submits monthly data as part of the requested reliability data to Staff (Steudle, 6T 2993-94, 3021-22).

AG-MN witness Alvarez recommended that the Commission "[r]equire DTE in its next rate case to identify the extent that it capitalized tree trimming costs in each program, each year, from 2021 through 2024" (Alvarez, 6T 3952). The Company already provides the capitalized costs associated with 4.8kV Hardening, which is the majority of tree trim capitalization costs, in the Tree Trim Annual Report (Steudle, 6T 3022). See also section VIII. F. 1 (Tree Trimming Capitalization).

Ann Arbor witness Giacobazzi suggested that the Company's tree trimmers should note tree damage specific to methane leaks and report it to Ann Arbor (Giacobazzi, 6T 4219). The Company disagrees because this is beyond the scope of training provided in the Tree Trimming program, and including it would require additional training and process development. The program should instead remain focused on the safe and efficient clearing of vegetation from around the Company's overhead infrastructure (Steudle, 6T 3023).

Therefore, the Commission should adopt the Company's tree-trimming requests and reject all contrary and additional proposals.

6. Community Lighting (Exhibit A-13, Schedule C5.6, line 23)

DTE Electric's Community Lighting O&M expenses for street lighting and signal systems are held steady at the 2022 historical level of $4.0 million, adjusted first for normalization attributable to an anticipated reduction in O&M related outage spend of $0.25 million, and then only for inflation, resulting in a forecasted O&M expense of $4.1 million in the projected test year (Bellini, 6T 3118; Exhibit A-13, Schedule C5.6, line 23).

Company witness Bellini explained and supported the Company's preventative maintenance programs, including (1) Post Inspections, (2) Post Painting, and (3) Night Patrol, which are O&M (6T 3109-10), as well as the Cable Replacement Program, which involves capital expenditures (6T 3111-12). He also discussed the Company's outage restoration activities and performance (6T 3112-14), which he summarized as follows:

> While any individual year will be impacted by external factors such as changing weather patterns (i.e., more freezing and thawing leads to increased cable faults) and number of catastrophic storms (i.e., construction crews being diverted to assist in power restoration activities), key outage metrics continue to trend in a positive direction when evaluating performance collectively, over the past six years. Specifically, the outage data summarized in Exhibit A-25, Schedule O1 indicates a positive impact in terms of the correlation between our proactive efforts resulting from the night patrol & underground cable replacement programs to reduce customer reported outage events (when adjusting for the removal of "ok on arrivals" and "streetlight knockdowns" and adding "follow-up events completed") from approximately 19,500 in 2019 to approximately 14,000 in 2023 as Chart 1 [at Bellini, 6T 3115] illustrates. [Bellini, 6T 3114.]

MI-MAUI witness Bunch proposed that the Commission "disallow any recovery of [post] inspection and painting costs in the test year" based on a narrow comparison indicating that the Company spent less than what the Commission approved in 2022 and 2023. The Company disagrees because when net outage O&M is included, the Company spent almost $900,000 more.

The actual combined spend for post inspections, post painting and net outage O&M shows that the Company under collected for both 2022 and 2023 compared to what the Commission approved. Therefore, the Commission should deny MI-MAUI's proposed disallowance (or conversely approve total O&M spend). (Bellini, 6T 3146, 3160-62).

The Company similarly disagrees with MI-MAUI witness Bunch's further recommendation that the Commission "order the Company to file as part of their next rate case a report on actual costs with amounts recovered in rates, looking back five years" (Bunch, 6T 4315-16). Isolating specific areas of Commission-approved spend to actual spend can be misleading. Company projections are snapshots in time based on information available at that time. There will be variances, both higher and lower, when actual costs are incurred (Bellini, 6T 3161-62).

7. Customer Service, including Merchant Fees (Exhibit A-13, Schedule C5, line 7; Schedule C5.7)

Company witness Hatsios supported the actual and projected O&M expenses for the Customer Service organization as reasonable and necessary (Hatsios, 6T 2284-2300; Exhibit A-13, Schedule C5.7).[111] These O&M expenses (including rate case adjustments) were $112.4 million for the 2022 historical test period, and are expected to increase to $118.6 million for the projected test year (Hatsios, 6T 2289, 2299; Exhibit A-13, Schedule C5.7, line 21, columns (g) and (m)).

Mr. Hatsios discussed the Customer Service organization's work activities performed in 2022 (Hatsios, 6T 2289-99). The projected O&M increase is based on continuing those activities, with (1) inflation adjustments of $3.1 million for 2023, $2.9 million for 2024, and $3.0 million for

[111] Customer Service has two divisions, which are (1) Operations and (2) Customer Strategy & Insight. Customer Service Operations includes Contact Center Operations, Metering, Billing & Exceptions, Revenue Management and Protection (RM&P), and Customer Service Operations Support. Customer Strategy and Insight includes Customer Service Transformation, Customer Service Analytics, Executive Consumer Affairs Center (ECAC), and Digital Experience (Hatsios, 6T 2285-88).

2025,[112] (2) an increase for fees paid to process credit card payments (merchant fees) of $0.5 million based on a continuation of cost mitigation strategies and an increase in customer growth, (3) a reduction in Customer Records and Collection Expenses of $6.4 million, and (4) ACPP / Time of Use Regulatory Asset Amortization of $3.0 million (Hatsios, 6T 2299-2300).

Company witness Bennett provided further background and details on merchant fees (Bennett, 6T 1979-81; Exhibit A-13, Schedule C.5.7.1, page 1, line 5). AG witness Coppola proposed a $3,474,000 disallowance of non-residential merchant fees, asserting that "[n]onresidential customers, which consist primarily of small to medium size commercial and industrial businesses, have more options and sophistication than residential customers to pay their gas and electric bills through other less costly means, such as Electronic Funds Transfer (EFT) and Automatic Clearing House (ACH)." (Coppola, 6T 3690). Witness Coppola further suggested that the Company should reimpose a convenience fee for customers like Consumers Energy did (Coppola, 6T 3691).

The Company disagrees. It already implemented two mitigation policies in Case Nos. U-20162 and U-20561,[113] so it believes that the 54,000 non-residential customers that utilized a credit card payment last year are largely small business customers that often utilize credit cards to run their businesses, and that might not use other tools like EFT. The National Small Business Association also indicates that approximately 37% of small businesses have used credit cards over the past 12 months to meet their capital needs, which suggests that facilitating credit card use for

[112] The rate of inflation is 3.2% for 2023, 2.9% for 2024, and 2.9% 2025 (Uzenski, 6T 1497; Exhibit A-13, Schedule C5.15, line 15).

[113] In 2019, the Company began mitigating merchant fees with a rate blocking policy for large commercial and industrial customers. In 2021, the Company further limited credit card usage for customers with over $75,000 in annual usage (Bennett, 6T 1981, 2017).

small businesses is a meaningful part of maintaining business customer satisfaction and financial flexibility (Bennett, 6T 2017).

8. Uncollectible Accounts Expense (Exhibit A-13, Schedule C5, line 8; Schedule C5.8)

Uncollectible expense is recorded in the income statement to reflect the portion of accounts receivable (AR) that is considered uncollectible. DTE Electric originally projected $50.9 million of uncollectible expense based on a three-year average of actual uncollectible expense for 2020-2022 (Sparks, 6T 2374-77; Exhibit A-13, Schedule C5.8, page 1, line 1, column (g)). The Company now supports $47.0 million consistent with the AG's proposal, as discussed below.

Staff projected $41,029,000 ($9,841,000 less than the Company's original request) based on the use of existing revenue instead of projected revenue, and excluding PSCR revenue (Rueckert, 6T 4991-92). The Company disagrees. Excluding PSCR revenue is inconsistent with how the historical uncollectible expense as a percent of revenue is calculated. The Company acknowledges that the Commission previously agreed with Staff's use of present revenue (December 1, 2023 Order in Case No. U-21297, p 211), but maintains that using rates currently in place and excluding PSCR revenue is unjust because it does not provide a reasonable chance for the Company to recover uncollectible costs that it will be incurring (Sparks, 6T 2381-82).

The Commission should instead use the previously-approved methodology of a three-year average of net write-offs to revenues, updated to include 2023 in the three-year average. AG witness Coppola did so by including projected revenue, including PSCR, and updating the three-year average to 2021- 2023, resulting in a $47.0 million projection ($3.8 million less than the Company's original request). (Coppola, 6T 3693). The Company agrees with this methodology and result, which increases Staff's projection by $6.0 million (Sparks, 6T 2383; Exhibit A-41, Schedule FF1).

9. Regulated Marketing (Exhibit A-13, Schedule C5, line 9; Schedule C5.9)

Regulated Marketing had $20.5 million of O&M expense for the 2022 historical test year (Exhibit A-13, Schedule C5.9, column (e), line 15). This expense included Major Account Services, Electric Marketing, Economic Development, Demand Response (DR) costs, Charging Forward O&M expense, and amortization of Charging Forward regulatory assets (Bennett, 6T 1985-86).

DTE Electric seeks to recover $32.2 million in the projected test year (Exhibit A-13, Schedule C5.9, column (k), line 15). Company witness Bennett outlined the known and measurable changes to the historical 2022 O&M expense, and supported the resulting projected expense as a reasonable and prudent level necessary to support the programs that the Company proposes in this case, as well as to maintain the existing level of customer support to commercial and industrial major account customers, support the Company's economic development activities, and educate all customers regarding Company offerings (Bennett, 6T 1986-87).

10. Corporate Support (Exhibit A-13, Schedule C5, line 10; Schedule C5.10)

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 $183.4 million for the 2022 adjusted historical test year, and are expected to increase to $198.2 million for the 2025 projected test year (Uzenski, 6T 1511-12; Exhibit A-13, Schedule C5.10, line 10, columns (f) and (l)). DTE Electric's proposed CSG cost-allocation methodology appropriately allocates costs based on the level of services consumed, and is the same methodology that the Commission approved in DTE Electric's general rate cases going back to Case No. U-13808, as well as DTE Gas's general rate cases going back to Case No. U-13898 (Uzenski, 6T 1514-16).

i. IT O&M Disallowances

Staff reduced O&M by $2.5 million related to its proposed disallowances of IT capital projects (Rogers, 6T 5112, 5117) The Company disagrees with the proposed capital disallowances, as discussed in section V. B. 7 (IT Capital Expenditures). To the extent that the Commission may decide to disallow the projects, however, the related O&M must be reduced by the amount not applicable to DTE Electric. The $2.5 million O&M cited by Staff is the amount supporting all DTE Energy users of the assets. The actual IT O&M costs recorded at DTE Electric are based on a bill down of approximately 74% of the costs, which is $1.8 million of the $2.5 million (Uzenski, 6T 1560, 1563; Exhibit A-37, Schedule BB1, line 18, column (g)).

ii. Corporate Memberships

In the Company's last general rate case, the Commission approved the Company's projected test year expense for corporate memberships, and added that "to ensure continued recovery of these corporate membership fees, DTE Electric shall provide in its next general rate case a detailed description of how these organizations *specifically* impact/benefit customers as outlined by the DAAOs, which will convey DTE Electric's roles and responsibilities in advancing ratepayer interests through its participation in each organization" (December 1, 2023 Order in Case No. U-21297, p 221. Emphasis in original. See also, November 18, 2022 Order in Case No. U-20836, p 308).

Accordingly, Company witness Foley explained 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 customer benefits and costs 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 specific 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, columns (d) and (e) provide the witness names and associated business units (Foley, 2T 100-101).

For example, Company witness Davis, representing Nuclear Generation, described the benefits that the Company realizes through its memberships in industry associations, and provided examples of specific benefits provided by the Electric Power Research Institute (EPRI), the Nuclear Energy Institute (NEI), and the Nuclear Procurement Issues Corporation (NUPIC). (Davis, 6T 1859-62).

Mr. Foley further explained that in addition to the Company's operating groups, the Company leverages the Edison Electric Institute (EEI) to benefit customers through many of the Company's workstreams (e.g., IT, Supply Chain) and internal organizations. He also provided ongoing and recent examples of how the Company's EEI participation benefits customers (Foley, 2T 102-103).

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 (Foley, 2T 102).

The membership costs associated with the organizations listed on Exhibit A-27, Schedule Q1, and that are proposed for inclusion in rates, do not include lobbying activities (Foley, 2T 101). Company witness Uzenski further explained how certain memberships and membership costs were excluded from customer rates (6T 1484; Exhibit A-3, Schedule C14).

DAAO witness Koeppel suggested that the Company did not follow the Commission's guidance from Case No. U-21297, and recommended that the Commission "disallow recovery of a significant portion, if not all, of the company's requested corporate membership expenses in this case" (Koeppel, 6T 4420). The Company disagrees because, as indicated above, it updated Exhibit A-27, Schedule Q1 to capture specific customer benefits related to each of its corporate memberships (Foley, 2T 179).

DAAO witness Koeppel also focused on the Company's membership in the Edison Electric Institute (EEI) and asserted that the "distinction between lobbying and non-lobbying activities is often blurry and subjective and may not fully capture the scope and influence of EEI's advocacy and outreach efforts," and that the "Commission should also be concerned about its own conflicts of interest" due to EEI's sponsorship of regulatory events (Koeppel, 6T 4427-28).

The Company disagrees. In addition to the discussion above about the exclusion of lobbying costs, the Company notes that positions taken by industry organizations like EEI do not necessarily reflect the position of its member companies simply because those companies pay membership dues. DAAO witness Koeppel's indicated belief that EEI has taken positions that are not in the best interests of customers (as he views them) does not negate the benefits of EEI membership (access to benchmarking, best practices, networking, and research, as reflected by Exhibit A-27, Schedule Q1, p 3) or provide sufficient justification to disallow the Company's proposed membership dues (Foley, 2T 179-80). [114]

[114] DAAO witness Koeppel offered subjective views that appeared to conflate his or DAAO's own interests with customers' interests, and acknowledged the contrary view that EEI's activities promote customer interests (e.g., Koeppel, 6T 4426). In any event, the Company's operations, as well as its customers' interests, are far more expansive than one person or intervenor's agenda, and it is reasonable and prudent for the Company to participate in memberships as discussed above.

DAAO witness Koeppel further suggested that the Commission should consider the "lack of detail about what specific activities are funded at what levels with DTE's contributions and lack any specific examples or quantitative evidence of how these benefits have actually translated into improved service quality, reliability, affordability, or other tangible outcomes for customers" (Koeppel, 6T 4431)

Witness Koeppel's suggestion should be rejected as unreasonable. The Company does not have the level of detail that he suggests. Attempting to compile such detailed information (assuming it is even available with industry associations; plus further extrapolate from it as Mr. Koeppel suggested) would be costly in terms of Company time and resources with no apparent benefit, and those costs would have to be passed on to customers (Foley, 2T 180).

Therefore, the Commission should again approve the Company's requested recovery of corporate membership expenses, and reject DAAO's contrary and additional suggestions.

11. Pension and Benefits (Exhibit A-13, Schedule C5, line 11; Schedule C5.11)

DTE Electric projects $103.59 million in employee pension and benefits costs. After adjustments for the portion of these costs capitalized, transferred and eliminated as being related to separate surcharge programs, this results in a net employee pension and benefits O&M expense of $84.259 million for the projected test year (Hooper, 6T 2943; Exhibit A-13, Schedule C5.11, line 31).

i. Pension

DTE Electric developed its projected pension expense based on the accounting requirements of U.S. GAAP Accounting Standard Codification (ASC) 715-30 (ASC 715-30), under which there are four components of pension costs, as described below:

Service Costs: This represents the pension benefits earned by active employees

during the current period on a present value basis. They are based on actuarial assumptions including current and projected salaries, expected employee turnover, and life expectancy.

Interest Costs: The interest cost recognized in the current period is the increase in the Projected Benefit Obligation (PBO) due to the passage of time. The PBO is the actuarial present value of benefits attributable to the pension benefit formula discounted back to current dollars at discount rates of 2.91% for the historical period, and 5.19% for the projected period. Measuring the PBO as a present value at the beginning of the period requires the accrual of an interest cost for the current period at a rate equal to the discount rate. The discount rate for the historical period is based on the interest rate environment at the end of 2021, the prior fiscal year end, and projected benefit payments from the pension plan matched against a yield curve of corporate bond rates, rated A or higher, provided by DTE Electric's independent actuarial firm, Aon. The 5.19% discount rate for the projected period is based on the discount rate as of December 31, 2022.

Expected Return on Assets (ERoA): This is an estimate of the expected investment return on assets invested in the pension trusts for the current period. Although actual year-to-year investment returns can vary significantly, the ERoA is determined based on forward-looking long-term financial market expectations in order to avoid large swings in pension costs based on short-term investment performance. DTE Electric's expected annual rate of return was 6.8% for the 2022 historical period, and is 7.6% in 2023, 7.9% in 2024, and 7.8% in 2025.

Unrecognized Gains and Losses: The cost of Unrecognized Gains and Losses reflects the amortization of the accumulated changes in the PBO or plan's assets resulting from actual experience in a given year that is different from that assumed in the actuarial assumptions for the year. Most notably, since discount rates and return on asset assumptions

are based on either point-in-time measurements or estimates, differences can arise due to changes in the discount rates, or when actual asset returns differ from long-range expectations.

Prior Service Costs: The amortization of Prior Service Costs relates to pension plan design changes that will affect future benefit payments (Fix, 6T 2855-58).

DTE Electric's annual pension costs are expected to decrease from $90.987 million in the historical test period to $53.993 million in the projected period, or $32.273 million inclusive of the effects of costs capitalized and transferred (Fix, 6T 2858; Exhibit A-13, Schedule C5.12.1).

The Commission previously adopted the Company's proposal that actual pension expense would be deferred to a regulatory asset if positive, or a regulatory liability if negative, with the net deferred amount carried on the balance sheet for review in a future rate case (November 18, 2022 Order in Case No. U-20836, p. 292). The Company proposes to continue the pension deferral mechanism, so the projected pension expense is not reflected in the Company's proposed revenue requirement and is eliminated on line 20 of Exhibit A-13, Schedule C5.12.1 (Uzenski, 6T 1498-99; Fix, 6T 2858-59).

Therefore, the Commission should continue the Company's proposed pension deferral mechanism.

ii. Other Post-Employment Benefit (OPEB) Expenses

DTE Electric's Other Post-Employment Benefit (OPEB) costs are related to the provision of retiree medical, dental, prescription drug, and life insurance benefits. DTE Electric's projected OPEB expenses are determined pursuant to U.S. GAAP Accounting Standard Codification 715-60 (ASC 715-60), which parallels ASC 715-30, reflecting the cost of benefits earned by employees during the year, the interest cost on the discounted Accumulated Post-Retirement Benefit

Obligation (APBO), the expected return on assets (ERoA) invested to meet the future liabilities, and the amortizations related to deferred gains and losses as well as prior service costs (Hooper, 6T 2920-22).

DTE Electric's OPEB costs are projected to increase from a negative $36.661 million in the 2022 historical test year to a negative $14.459 million in the 2025 projected test year, or negative $8.395 million, inclusive of the effects of costs capitalized and transferred (Hooper, 6T 2922; Exhibit A-13, Schedule C5.12.2, line 17).

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 (Uzenski, 6T 1498; Hooper, 6T 2922-23; Exhibit A-13, Schedule C5.12.2, line 18).

The Commission previously adopted a seven-year amortization of the Company's $128.4 million OPEB regulatory liability as of December 31, 2022 (December 1, 2023 Order in Case No. U-21297, p 223-24). which resulted in annual $18.3 million amortization that is reflected as a reduction to OPEB expense (Uzenski, 6T 1498-99; Hooper, 6T 2923; ExhibitA-13, Schedule C5.11, line 3, and Schedule C5.12.2, line 19).

iii. New Hire VEBA Expense

New Hire VEBA costs (Exhibit A-13, Schedule C5.11, line 4) reflect the costs of the DTE Supplemental Retiree Benefits Plan that is offered in lieu of the traditional retiree healthcare plan

for eligible employees, as adjusted for the portion of costs capitalized. The Company's traditional retiree healthcare plan is closed to new participants, so the costs of the New Hire VEBA plan are offset by avoided OPEB costs. The Company calculated the costs by: (1) normalizing the recorded 2022 New Hire VEBA expense, and (2) projecting this expense through the end of the projected test year (Exhibit A-13, Schedule C5.11, line 4, columns (c) and (h)). The New Hire VEBA expense is expected to increase from the normalized 2022 historic test year expense of $7.707 million to $9.847 million in the projected test year, which represents an average annual increase of 13.8% (Hooper, 6T 2924-26; Exhibit A-13, Schedule C5.11, page 1, line 4, column (d), and page 2, line 4, column (j)).

Company witness Hooper further explained that a normalization adjustment is required for the Company's recorded 2022 New Hire VEBA expense because in 2022, the Company recognized an unusually high non-recurring true-up related to the New Hire VEBA costs recognized in 2021 compared to the actual funding requirement for 2021. There were two primary drivers for this. First, due to historically low levels of employee turnover during the COVID-19 pandemic in 2020, there was a reduction in the number of new hires eligible to participate in the plan in 2021. Second, as the Company transitioned out of the pandemic in 2021 and employee turnover increased, there was a substantial increase in the number of forfeitures of accumulated balances by employees who left the Company before they were vested in the plan. Accordingly, the Company's 2022 recorded New Hire VEBA costs should be increased by $1.027 million, which represents the excess of the 2021 true-up over the average of true-ups recognized in the prior five years. The projected expense was then calculated based on the Company's experience with new plan participants, the Company's required contributions for each plan, and plan participants leaving the Company before they were vested in the plan (Hooper, 6T 2925-26). No party has proposed any adjustments to the Company's projection.

iv. Employee Savings Plan (ESP)

The Company's Employee Savings Plan (ESP) allows eligible employees the opportunity to put aside a certain percentage of their annual earnings, which the Company matches up to 6%, of annual salaries and wages for non-represented employees and for most represented groups. In addition, employees hired after the defined benefit pension plan closed to most new hires generally receive an additional employer contribution of 4.0% of annual salaries and wages. The Company calculated the costs by: (1) normalizing the Company's recorded 2022 ESP expense, and (2) projecting this expense through the end of the projected test year (Exhibit A-13, Schedule C5.11, page 2, line 5, columns (c) and (h)). (Fix, 6T 2859-60).

Company witness Fix further explained that a normalization adjustment is required for the Company's recorded 2022 ESP expense because the Company realized an abnormally high number of employee resignations in 2021, which were likely driven by a transition out of the COVID-19 pandemic, and that resulted in an abnormally high level of forfeitures in 2022 due to employees leaving the Company prior to vesting ($0.837 million, as compared to the five-year average of ($0.459 million). Eliminating the excess forfeitures ($0.378 million) results in adjusted 2022 ESP expense of $30.077 million (Exhibit A-13, Schedule C5.11, page 2, line 5, column (d)). (Fix, 6T 2860).

The normalized 2022 ESP expense was then escalated by 7.5%, which is the four-year average of the average increase in ESP costs for 2017 through 2020, and assumes that the proportion of costs capitalized will remain constant through the projected test year.[115] This results in ESP

[115] Both 2021 and 2022 were excluded from the annual escalation because they were impacted by the COVID-19 pandemic, which is a definitive one-time experience. In 2021, ESP costs were impacted by the low level of new employees during the pandemic. In 2022, the Company recognized a high level of forfeitures arising from employee resignations in 2021, as the economy transitioned out of the pandemic (Fix, 6T 2861). This is also consistent with the ALJ's recommendation and the Commission's decision in the Company's most recent rate case (December 1, 2023 Order in Case No. U-21297, p 191).

expense for the projected test year of $37.406 million (Fix, 6T 2860; Exhibit A-13, Schedule C5.11, page 1, line 5, column (d), and page 2, line 5, column (j)).

Staff instead projected $29.547 million ($7.859 million less than the Company's projection) using the 2023 ESP expense of $27.286 million escalated by 4.06% annually based on a five-year (2019-2023) average of the annual change in ESP costs (Rueckert, 6T 4993). The Company disagrees. Staff's use of 2023 ESP expense as a starting point is improper because the Company capitalized an abnormally high proportion of ESP costs in 2023 (Uzenski, 6T 1575; Fix, 6T 2908).

As an alternative to Staff's calculation, Exhibit A-35, Schedule Z2 updates Staff Exhibit S-15.4 by using the 2022 percentage of ESP expensed (60.4%) instead of the 2023 percentage (54.6%), resulting in adjusted 2023 expense of $2.901 million. Exhibit A-36, Schedule AA5 then uses this starting point and escalates it by 4.06% (as Staff did) resulting in a 2025 ESP expense of $32.688 million ($3.141 million increase to Staff's projection). (Fix, 6T 2908-2909). It is worth noting that the use of the proportion of ESP costs capitalized in 2022 rather than the 2023 proportion is consistent with the Staff's use of the 2022 proportion of Active Healthcare costs (4 T 2908).

v. 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 $50.126 million in the historic test year, to $56.083 million in the projected test year (Exhibit A-13, Schedule C5.11, line 11). This increase reflects the normalization of the 2022 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 $1.260 million (Exhibit A-13, Schedule C5.11.3). The 2022 normalized Active Healthcare costs of $48.866 million are then escalated for the adjusted medical plan trend of 5.1% in 2023, 5.0% in 2024, and 4.0% in 2025 (Hooper, 6T 2927, 2936).

Company witness Hooper further explained that annual unadjusted medical trend factors of 7.1% for 2023, 7.5% for 2024, and 7.0% for 2025 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. [116] WTW's trend factors are reduced by 2.0% in 2023, 2.5% in 2024, and 3.0% in 2025 to reflect the expected savings from the Company's Wellness program (to 5.1% in 2023, 5.0% in 2024, and 4.0% 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 6.0% in 2023, and 7.0% in 2024 (Hooper, 6T 2935-38).

Company witness Hooper also demonstrated that the Company's historical annual changes in its Active Healthcare costs have been extremely volatile over the last 10 years, with the annual percentage change of as high as 27.2% in 2021 and as low as -4.5% in 2018. This high variability in the Company's Active Healthcare costs highlights the inherent flaw in using historical changes in these costs as a basis for projecting future increases in the Company's Active Healthcare costs. This volatility is created by variations in usage, the effect of plan design changes, and changes in pricing. Moreover, the Company only has about 3,400 employees (and their eligible dependents) covered by the Company's self-insured medical plans, which is too small of a sample size to infer that the experience over a few years is predictive of the Company's future costs. Accordingly, the adjusted trend factors of 5.1% in 2023, 5.0% in 2024, and 4.0% in 2025 reflected in Company witness Hooper's projected Active Healthcare expense, which are based on national trends, represent a superior source for predicting future costs than the Company's historical annual cost changes (Hooper, 6T 2927-29, 2939-40).

[116]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 (Hooper, 6T 2936).

The constant dollar normalization adjustment is needed to establish an accurate starting point because 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 negative $1.260 million constant dollar normalization adjustment to the Company's actual 2022 Active Healthcare costs is designed to eliminate this volatility and reduce the risk of selecting an unrepresentative starting point. The volatility of the Company's actual Active Healthcare costs is graphically demonstrated on Table 1 of Company witness Hooper's direct testimony (at 6T 2938) where annual changes range from a 27.2% increase in 2021 to a 4.5% decrease in 2018. Although the average annual increase in the Company's Active Healthcare costs for 2013 through 2022 was 2.7%, the standard deviation was 9.4%. This means that for about 68% of the years, the annual change could range from negative 6.7% to positive 9.1%. 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 (Hooper, 6T 2927-30, 2939-40).

The normalization mechanics (reflected on Exhibit A-13, Schedule C5.11.3) 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 (Hooper, 6T 2930-33).

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 cases (November

18, 2022 Order in Case No. U-20836, p 63; December 1, 2023 Order in Case No. U-21297, p 76). The constant dollar Active Healthcare adjustment follows the same logic (Hooper, 6T 2933).

The Company recognizes that the Commission previously declined to adopt the constant dollar normalization in this context, finding that the Company "insufficiently demonstrated that its proposed constant dollar normalization will not result in compounded inflationary increases" (December 1, 2023 Order in Case No. U-21297, p 232). The Company maintains that it has made that demonstration here. In addition to the discussion above, Company witness Hooper explained that this normalization adjustment is like the normalization of historic emergent replacement expenditures. It merely recasts the Company's historical Active Healthcare costs for the impact of historical medical cost escalations. The only difference is the use of medical cost trends rather than overall inflation, which is appropriate in this medical cost context. The end result is the same, which is the creation of an accurate starting point to be used to project future costs (Hooper, 6T 2934-35).

Staff proposed $53,749,000 (a $2,334,000 reduction from the Company's projection of $56,083,000) based on the Company's 2023 Active Healthcare expense, escalated by 4.83% annually (average annual growth rate in total Active Healthcare costs for 2018-2023). (Rueckert, 6T 4994).

The Company disagrees and maintains its position as explained and supported above. Staff's methodology is flawed because (1) it relies on a single year of the Company's Active Healthcare costs as a starting point, instead of the Company's constant dollar normalizing starting point, and (2) it uses an historical average of actual percent changes in the Company's Active Healthcare costs, instead of the Company's use of projected medical trend rates (Hooper, 6T 2931-35, 2947).

If the Commission were to use Staff's methodology, however, then the methodology should at least be corrected. Staff's methodology includes a one-time credit that the Company received in 2023 from its Pharmacy Benefit Manager (PBM), which reduced Active Healthcare costs by $1.134

million. This was a non-recurring item, so it should be excluded from both the starting point and the average annual escalation rate. This increases the starting point to $49.589 million, and the annual escalating rate to 5.11%, resulting in a projected Active Healthcare expense of $54.784 million, or an increase to Staff's projection of $865,000 (Hooper, 6T 2948; Exhibit A-36, Schedules AA1 and AA5).

The AG projected Active Healthcare costs of $52.947 million based on the Company's 2023 Active Healthcare costs with annual escalations of 3.33%, which is apparently based on the compound average growth rate in Active Healthcare costs from 2017 to 2022 (Coppola, 6T 3696, Hooper 4T 2951).

In addition to the discussion above, it is inconsistent and unjustified for AG witness Coppola to develop an average annual percent change based on an historical period that excludes the most recent data (2023), and then use 2023 as the base year in developing the AG's projected Active Healthcare costs. Witness Coppola's proposed inclusion of 2017 and exclusion of 2023 dramatically understates the average annual percent change for five years by 29.0% (3.96% for the years 2017 through 2022 versus 5.11% for the years 2018 through 2023), and the compound growth rate for the five-year period by 36.3% (3.35% for the years 2017 through 2022 versus 4.56% for the years 2018 through 2023). Therefore, the AG's proposal should be rejected (Hooper, 6T 2949-50; Exhibit A-36, Schedule AA2).

If the Commission were to use the AG's methodology, however, then it should be corrected, which would be fairly simple. AG witness Coppola proposed a 2023 starting point that recognized the one-time PBM credit and the adjustment for the abnormally high proportion of Active Healthcare costs capitalized in 2023, so it matches the corrected Staff starting point ($49,589 million, as reflected on Exhibit A-36, Schedule AA5 and discussed above). Thus, the only correction needed is to update the five-year average of annual changes in costs to 5.11% (as

developed on Exhibit A-36, Schedule AA5). This results in an Active Healthcare expense of $54.784 million (a $1.837 million increase to the AG's proposal). (Hooper, 6T 2951).

Therefore, the Commission should approve the Company's requested $56.083 million Active Healthcare expense, and if the Commission were to instead calculate the expense using the Staff or AG approach, then the Commission should at least correct those calculations and adopt an Active Healthcare expense of $54.784 million, as described above.

vi. Other Employee Benefit Costs

The Company's Other Employee Benefits are projected to increase from $5.318 million in 2022 to $18.554 million in the projected test year (Exhibit A-13, Schedule C5.11, line 26). These costs include a variety of other benefits including Accrued Vacation, Supplemental Severance Plan, Wellness Plan, Long-Term Disability expense, costs associated with the Affordable Care Act (ACA), General Benefits expenses, as well as the Supplemental Savings Plan and Deferred Compensation Plan. The increase consists of $11.70 million in normalization adjustments, and $2.067 million in projected increases (Fix, 6T 2862; Hooper, 6T 2940; Exhibit A-13, Schedule C5.11, page 2, Columns (c) and (i)).

The Company's projected Supplemental Savings Plan (SSP) expense for the projected test year is 3.207 million (Exhibit A-13, Schedule C5.11, line 15, column (d)). AG witness Coppola proposed a complete disallowance, reasoning that the SSP "is similar to the expense for the Supplemental Employee Retirement Plan (SERP), which the Commission has previously rejected" (Coppola, 6T 3697). [117]

[117] DTE Electric has two employee benefit programs that do not qualify for tax-advantaged status under the Internal Revenue Code: the Executive Supplemental Retirement Plan (ESRP) and the Supplemental Retirement Plan (SRP). The Commission has traditionally denied recovery of ESRP and SRP costs, and the Company does not seek to recover its ESRP and SRP expenses. The AG's "SERP" reference presumably is to these non-qualified plans (Fix, 6T 2862).

Witness Coppola's proposal should be rejected because his characterization of the SSP is inaccurate and neglects that the Commission has previously authorized the recovery of SSP costs. The benefits provided through the SSP are exactly the same for those plan participants as for other employees under the qualified savings plan. The only reason that these benefits are provided through the SSP is because of Internal Revenue Code (IRC) provisions. The SSP is merely a "make-whole" plan to avoid employees being deprived of savings plan benefits they would have otherwise had but for IRC limitations (Fix, 6T 2863, 2909-10).

Moreover, the SSP's cost recoverability is well-established. For example, the December 23, 2008 Opinion and Order in Case No. U-15244, p 34, approved SSP recovery where "Staff agrees that the SSP was erroneously omitted" and that "the SSP should be included in O&M expenses recoverable from ratepayers." In a subsequent proceeding, Staff changed its position to assert essentially the same thing that the AG now repeats—that SSP expense should be disallowed because the SSP allegedly "includes elements like those of the Company's supplemental executive retirement plans (SERPS) . . . ." (Staff initial brief in Case No. U-18255, p 67). The Commission rejected Staff's argument, following its decision in Case No. U-18244 as "directly on point" (April 18, 2018 Order in Case No. U-18255, p 52).

Nothing has changed to now cause these recoverable costs to become unrecoverable, nor does AG witness Coppola acknowledge past decisions, or offer support for a different result. This is the same argument that has been previously rejected. Therefore, the AG's proposed SSP disallowance should be rejected, and the Commission should approve the Company's requested $3.207 million SSP expense (Fix, 6T 2910-11).

The Company projected a General Benefits expense of $2.395 million (Exhibit A-13, Schedule C5.11, line 21, column (d)). Staff proposed a $1.344 million decrease to $1.051 million

based on actual 2023 General Benefits expense escalated by a five-year average of the annual percent change in the expense of negative 10.24% (Rueckert, 6T 4995-96).

Staff's proposal has four flaws so it should not be used. First, it is based on the Company's actual 2023 expense, ignoring two one-time items that reduced that expense ($629,000 for the temporary suspension of the tuition reimbursement program, and $651,000 for employee service anniversary awards) so it is necessary that they are excluded from the starting point (Hooper, 76T 2951-52). Second, using the unadjusted (for the two one-time expense reductions) 2023 expense also caused the five-year average of the annual change in expense to be understated (Hooper, 6T 2952). Third, Staff computed the negative 10.24% average annual change based on the annual percent change in General Benefits expense, which is improper because the historical average is distorted by changes in the proportion of General Benefits costs capitalized. For example, the proportion of General Benefits costs allocated to expense was 68.0% in 2018, but declined to 58.7% in 2023. A more meaningful measure of the average annual percent change would be based on the change in General Benefits costs (Hooper, 6T 2952-53). Fourth, Staff used the 2023 actual proportion of General Benefits costs capitalized, which was distorted by O&M reductions implemented in 2023 due to the Company's financial challenges, so the projected General Benefits expense is understated. The proportion of General Benefits costs allocated to expense in 2022 is more representative of the proportion that will be allocated in the projected test year. While Staff correctly used the 2022 proportion of total Active Healthcare costs capitalized rather than the proportion of such costs capitalized in 2023, Staff's projected General Benefits expense is incorrectly based on the proportion of these costs capitalized in 2023. (Uzenski, 6T 1561, 1575; Hooper, 6T 2952-53).

If the Commission were to use Staff's methodology, then the methodology should at least be corrected. The Company revised Staff's methodology to include the two one-time adjustments,

the annual escalation based on the total General Benefits costs and use of the proportion of General Benefits costs allocated to expense in 2022, resulting in an adjusted General Benefits expense for 2025 of $2.239 million ($1.188 million higher than Staff's projection). (Hooper, 6T 2954-55; Exhibit A-36, Schedules AA3 and AA5).

The Company projected Benefit Administration Fees (BAF) of $7.296 million (Exhibit A-13, Schedule C5.11, line 22, column (d)). Staff proposed a $2.855 million decrease to $4.708 million (Rueckert, 6T 4996). Staff's proposal has two flaws so it should not be used. First, Staff's five-year average of the annual change in BAF is based on the Company's BAF expense, after reduction for the proportion of costs capitalized, which like General Benefits, is distorted by changes in the proportion of BAF capitalized during the five-year period. Second, Staff's projected BAF is based on the percentage of BAF allocated to expense in 2023, which was distorted by one-time O&M reductions that the Company implemented in 2023 (Uzenski, 6T 1561, 1575; Hooper, 6T 2955).

Again, if the Commission were to use Staff's methodology, then the methodology should at least be corrected. The Company revised Staff's methodology to account for these matters, resulting in an adjusted BAF for 2025 of $5.372 million ($664,000 higher than Staff's projection) (Hooper, 6T 2956; Exhibit A-36, Schedules AA4 and AA5).

12. Employee Compensation

DTE Electric's overall employee compensation philosophy is to provide pay programs that (1) attract, retain, and motivate employees; (2) is externally competitive (i.e., pay is near the market median); and (3) differentiate total rewards based on both organizational unit results and individual contributions (Fix, 6T 2867). The Company's incentive compensation programs for both its executive and non-executive employees consist of short-term incentive plans provided through the

Annual Incentive Plan (AIP), applicable to senior management 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 Fix provided a detailed description of the design and mechanics of these plans (Fix, 6T 2867-97; Exhibit A-21, Schedules K1 through K6).

DTE Electric proposed to recover the $59.504 million net projected test period incentive compensation expense, which excludes the expense allocated to the Company for DTE Energy's top five executives (Fix, 6T 2875-76). The performance measures included within the plans incorporate both operating and financial metrics. The components of these expenses are reflected in the table below, as differentiated for the portion of such expenses based on operating versus financial performance measures (Fix, 6T 2889).

	LTIP	AIP	REP	Total
Financial	$20.4	$4.2	$14.6	$39.2
Operating	$0.0	$4.6	$15.7	$20.3
Total	$20.4	$8.8	$30.3	$59.5

The operating measures reflected in the short-term incentive plans relate to Customer Satisfaction, Safety and Engagement and Operating Excellence, as appropriately customized for the specific business units. Customer Satisfaction measures are intended to focus employees on improving the experience that customers have in their interactions with the Company. Safety and Engagement measures encompass employee engagement as measured by the Gallup survey and employee safety. Operating Excellence includes measures related to generation and distribution reliability, as well as additional specific measures related to the nuclear generation business unit

(Fix, 6T 2882-86). Company witness Fix also explained how the benefits of the operating measures are quantified (6T 2892-96).

Staff proposed to exclude $39,232,000, representing the entire incentive compensation expense related to financial measures, based on past decisions by the Commission (McMillan-Sepkoski, 6T 4925-26). Staff further proposed the disallowance of $8,960,000 of Restricted Stock expense, reasoning that "Restricted Stock is considered as a reward to employees for assisting the Company in reaching its financial performance goals" (McMillan-Sepkoski, 6T 4929). The Company understands Staff's adjustments in this proceeding, however DTE Electric believes its proposal to include incentive compensation expense for all measures is transparent and fully supported by the record in this case (Fix, 6T 2882-96). DTE Electric provided an in-depth cost/benefit analysis demonstrating a $44.974 million net customer benefit ($104.478 million total customer benefits minus $59.504 million total incentive plan costs). (Fix, 6T 2891-96; Exhibit A-21, Schedule K6).

Incentive compensation programs are the prevalent practice among the vast majority of energy companies.[118] 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

[118] 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 (Fix, 6T 2878).

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 (Fix, 6T 2867-72).

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, 2022 shows that the Company's total compensation is insignificantly different from market medians (Fix, 6T 2872-74; Exhibit A-21, Schedule K1). Moreover, without the Company's short-term incentive compensation programs, the Company's pay would be 10.7% less than the market medians (Fix, 6T 2874).

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 (Fix, 6T 2867-68, 2870).

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 (Fix, 6T 2868, 2877-78).

In addition to the exclusion of the incentive compensation expense related to financial measures, AG witness Coppola also proposed to exclude 52.6% of incentive compensation expense relating to operating measures based on his analysis of the operating performance levels achieved for the years 2019 through 2023 (Coppola, 6T 3706). Company witness Fix 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 that can produce payouts. Exhibit A-35, Schedule Z1 shows that for the last five years, the actual weighted performance was 79.3% for the AIP, 81.5% for the AIP Executives, and 69.2% for the REP, for a combined average of 76.6% (Fix, 6T 2901-2903).

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 47.4% of operating performance measures will be achieved as AG witness Coppola suggested. 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 (Fix, 6T 2903).

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." (April 18, 2022 Order in Case No. U-18255, p 49; see also May 5, 2019 Order in Case No. U-20162, 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.[119]

The Company recognizes that more recently, the Commission adopted the AG's proposed 40% disallowance of operating measures (November 18, 2022 Order in Case No. U-20836, p 301). 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." (*Id*., pp 301-302). In the Company's last rate case, the Commission continued the deferral treatment above or below the base amount, but lowered the base amount assuming the Company achieves approximately 52% of its targeted metrics (December 1, 2023 Order in Case No. U-21297, p 239).

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[119] The Commission long ago recognized that: "Executive bonuses have often been viewed as an appropriate cost of operating a utility." (October 28, 1993 Order in Case Nos. U-10149 and U-10150, 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:

> [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)… [December 11, 2015 Order in Case No. U-17767, p 76.]

The mechanism is unnecessary if the Commission approves the Company's requested recovery of all the incentive compensation expense related to the operating measures. If the Commission approves a lesser amount, however, then the Company would request that the deferral be continued, but with two 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 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 results fell below the baseline, it is reasonable to include the cost of achieving exceptional results (Uzenski, 6T 1547-48).

In addition to the exclusion of the financial measures, ABATE also proposed the exclusion of expense related to those operating measures that do not have a measurable net customer benefit (Customer Satisfaction and Safety) and to exclude the expense related to SAIDI including MEDs and CEMI4, totaling $9.539 million (York, 6T 3345-46). The Company disagrees. In addition to the discussion above, ABATE's proposal is flawed for the following reasons.

First, the cost/benefit analysis reflected in Exhibit A-21, Schedule K6 represents only the reasonably-quantified financial benefits of the Company achieving target performance for each of the metrics included in the incentive compensation plans. It is important to recognize that certain measures provide benefits to customers but evade specific quantification. For example, the quantifiable benefits of the MPSC Customer Complaints measure is only $29,000 based on time savings but does not include additional unquantifiable benefits to customers (such as avoidance of frustration) or savings by the Commission resulting from a reduction in complaints (Fix, 6T 2904-2905).

The Commission has also consistently assessed net customer benefits on an aggregated basis, and not the net benefits for each measure. ABATE's proposal is contrary to this long-standing practice, and is unsupported by any explanation to support such a change (Fix, 6T 2906).

ABATE's proposal to exclude incentive compensation expense related to SAIDI, excluding MEDs and CEMI4, is also apparently based on the incorrect assumption that if the Company does not achieve Target levels, then there will not be any payout. Instead, as discussed above, payouts are based on a range of performance between Threshold and Maximum. ABATE witness York asserted that "the target SAIDI excluding MEDs in 2023 was 150 minutes, but the Company Achieved 157 minutes" (York, 6T 3346. Footnotes omitted). This neglects that the Company still had payouts because actual performance exceeded the Threshold (180 minutes). ABATE witness York also relied on just one year (2023), where CEMI4 performance was less than Target, ignoring that the Company's CEMI4 performance was above Target in 2022. It is unreasonable to rely on just 2023 to assess the probability of the Company achieving its targets in 2025 (Fix, 6T 2907).

ABATE witness York further asserted that a portion of the Company's incentive compensation recovery should be disallowed based on the Company's "track record of historic revenue sufficiency amounts" (York, 6t 3346). ABATE's proposal lacks merit because this case uses a projected test year, in accordance with well-established law and practice, as discussed above in section IV. Therefore, the Company's historical revenue is irrelevant to the Company's proposed recovery of incentive compensation (Foley, 2T 186). ABATE also essentially proposes "retroactive ratemaking," which is illegal as discussed above in section III.

In summary, DTE Electric has demonstrated in detail that the customer benefits of its incentive compensation plans significantly outweigh their costs, that the total compensation is reasonable in comparison to the Company's peers.

D. Depreciation and Amortization, and AFUDC

DTE Electric projected $1,266.2 million of depreciation and amortization (D&A) expense for the projected test period (Exhibit A-13, Schedule C1, line 5; Schedule C6). Company witness Uzenski supported the Company's projected D&A expense, explaining that it includes book depreciation, which is based on existing plant balances, plus new capital expenditures and assumed retirements, using a half year convention. Depreciation expense was calculated using the rates authorized by the Commission in Case No. U-18150 (Uzenski, 6T 1504).

The projected $210.1 million D&A increase from 2022 normalized D&A expense of $1,056.2 million was due primarily to $254.0 million for capital in-service movement. The increase is also driven by approximately $47.6 million due to reclassifying $2.1 billion of Monroe generation net plant to a regulatory asset effective December 31, 2024. These increases are partially offset by approximately $65.7 million for plant retirements, and software amortization also decreases by $25.6 million in the projected period. (Uzenski, 6T 1504. See also, 79-81).

As discussed in Section I, the Company has now made a $29.1 million reduction to its capital projections. This reduction correspondingly reduces the Company's projected D&A expense by $1.4 million. These adjustments result in a revised projected D&A amount of $1,264.8 million, which should be approved by the Commission.

E. Property and Other Taxes

DTE Electric seeks to recover $328.8 million of property tax expense for the 2025 projected test year (Wisniewski, 6T 2836-37, 2844; Exhibit A-13, Schedule C1, column (e), line 6). This

amount is calculated by taking 61% of the 2024 calendar year liability, plus 39% of the 2025 calendar year liability (Wisniewski, 6T 2836-37). [120]

The AG (Coppola, 6T 3708), ABATE (York, 6T 3361), and Staff (Hecht, 6T 4889-90) proposed property tax adjustments corresponding to their respective proposals for capital expense disallowances. Company tax expert Wisniewski explained why the AG and ABATE's methodologies for calculating property tax adjustments are incorrect (6T 2843-45), and that to the extent the Commission orders a capital expense disallowance, the Commission should calculate the corresponding adjustment to property taxes using Staff's methodology (6T 2845-47).

DTE Electric projects a $53.2 million Other Tax Expense for the projected test year, consisting of payroll taxes ($39.3 million), Public Utility Assessment fees ($13.6 million), and miscellaneous other taxes ($0.2 million) as shown on Exhibit A-13, Schedule C7, column (j), lines 2-5 (Wisniewski, 6T 2837).

F. Income Tax Expenses

DTE Electric seeks a total income tax recovery of $169.2 million for the projected test year, consisting of a $107.8 million federal income tax (FIT) expense, based on a 21% FIT rate (Exhibit A-13, Schedule C8, line 53), a $58.4 million Michigan Corporate Income Tax (MCIT) expense, based on a 5.88% rate (Exhibit A-13, Schedule C9, line 14), and a $3.0 million municipal income tax expense, based on a 0.33% composite municipal income tax rate (Exhibit A-13, Schedule C10, line 11). (Wisniewski, 6T 2828, 2838-39).

[120] The projected 2024 property tax liability is $313.8 million (Wisniewski, 6T 2834; Exhibit A-13, Schedule C7.1, column (c), line 54). The projected 2025 property tax liability is $349.7 million (Wisniewski, 6T 2835; Exhibit A-13, Schedule C7.1, column (e), line 56). Property tax *expense* is the amount of property taxes deducted for book purposes. Property tax *liability* is the amount of property taxes payable to local governments. The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. This two-year allocation methodology has been used for many years, and is generally based on the fiscal years of the various taxing jurisdictions to which property taxes are paid (Wisniewski, 6T 2828, 2833, 2836-37, 2844).

The overall methodology for amortizing the Tax Cuts and Jobs Act (TCJA) regulatory liability (reflected in Exhibit A-13, Schedule C8.1) is consistent with the December 1, 2023 Order in Case No. U-21297. Amortization for the 2025 test period reduces tax expense by $50.2 million (Wisniewski, 6T 2838; Exhibit A-13, Schedule C8, line 49).

VIII. OTHER REVENUE-RELATED ISSUES[121]

A. Infrastructure Recovery Mechanism (IRM)

The Company seeks to extend and expand the IRM that the Commission authorized in Case No. U-21297. Company witness Foley recounted for context that the Company previously proposed a roughly three-year Distribution IRM that would begin concurrent with the projected test year in Case No. U-21297 (on December 1, 2023). Typical distribution planning and reporting activities are completed on a calendar year basis, so the Company proposed that the IRM's first year extend 13 months and cover all of 2024. IRM Plan Year 2 would be calendar year 2025, and Year 3 would be calendar year 2026. In Case No. U-21297, the Company proposed IRM treatment for five capital programs focused on safety and reliability:

1. Conversions;
2. Sub-transmission Redesign & Rebuild;
3. Breaker Replacement;
4. Underground Residential Distribution (URD) Replacement; and
5. 4.8 kV Circuit Automation (Foley, 2T 113-14).

[121] (See generally supra, Section II. History of Proceedings – *DTE Electric* – Foley, Elliott Andahazy, Hartwick, Vangilder, Maroun, Willis, Kryscynski, Uzenski, Bennett; *Attorney General* – Coppola; *ABATE* – Dauphinais ; *Staff* – Evans, Duell, Krause; *AG-MN* -- Alvarez; *CUB-MN* – Denzler; *Walmart* – Perry; *Ann Arbor* – Stults; *MEIU* – Sherman; *EVgo* – Stegall; *Electrify America* – Davis, Shah; *MNSC* – Jester; *GLREA* – Richter; *DAAO* – Koeppel, Watts)

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. If the Company were to invest less in a program than the level authorized for that program, then the over-recovery would be returned to customers. 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. The Company also proposed two new stakeholder processes: (1) IRM Planning Process occurring before the start of each IRM Plan Year, and (2) IRM Reconciliation Process occurring after the conclusion of each IRM Plan Year (Foley, 2T 114-15).

The Company highlighted four benefits that would be realized immediately through the implementation of the IRM: (1) certainty of investment in key distribution capital programs; (2) greater transparency into both the Company's investment plans and its execution of those plans; (3) additional opportunities for Staff to review and provide input on the Company's investment plans; and (4) increased accountability for the Company through the reporting of new program execution metrics. In addition to these immediate benefits, another potential future benefit is to extend the time between rate cases, reducing administrative burdens and costs (Foley, 2T 115).

Staff supported the IRM in Case No. U-21297, but proposed modifications in response to the Company's proposal that it would submit an IRM Investment Plan to Staff no later than two months prior to the start of each IRM Plan Year.[122] The Commission essentially approved the

[122] Staff proposed:

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.

Company's proposed IRM for two years, with Staff's modifications (but recognizing that first year timing could be challenging), and with approved spending of $61,865,000 in the 13 months ending December 31, 2024, and $290,134,000 for the 12 months ending December 21, 2025 (December 1, 2023 Order in Case No. U-21297, pp 289-91). The Commission described how to move forward with the IRM:

> The Commission finds that there is value in the company's proposal, with some limitations. First, the Commission adopts each of the Staff's recommendations with the understanding that, for the first plan year, the timeframe may be constrained. The filing of the IRM Investment Plan at least four months prior to the start of each plan year will allow for a more meaningful review by both the Staff and other interested stakeholders. Further, the submission of the plan to all intervening parties, along with providing a forum for interested parties to raise concerns, will allow for additional collaboration and input into the proposed investments.
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> In addition, the Commission finds that approval is limited to Plan Years 1 and 2. As noted on the record, there is ongoing discussion regarding PBR in Case No. U-21400 and an ongoing audit in Case No. U-21305. Therefore, the Commission finds that limiting the approval to the first two years will allow the company to move forward with the IRM without precluding the incorporation of any potential insights gained from those proceedings to better inform the potential continuation of the IRM.
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> With respect to the reconciliation process . . . the IRM reconciliation shall be filed as a contested case proceeding . . . Finally, the Commission agrees with ABATE that DTE Electric shall remove any allocation of IRM costs from transmission level customers. [December 1, 2023 Order in Case No. U-21297, pp 289-90. Footnote omitted.]
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> Z. As described in this order, DTE Electric Company shall submit an investment recovery mechanism plan no later than four months prior to the start of each investment recovery mechanism plan year; submit a copy of this plan to all intervening parties in the company's most recently filed general rate case, including the Commission Staff; and shall schedule and provide a forum no later than two months before the start of the investment recovery mechanism plan year, for the

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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. [U-21297, Staff Initial Brief, p 149.]

> Commission Staff and intervening parties to raise any questions or concerns that they may have before execution of the plan begins. Regarding the time constraints for the first investment recovery mechanism plan year recognized in this order, the company shall use best efforts to provide its investment recovery mechanism plan as soon as practicable that will in turn, allow the company to schedule the forum as soon as practicable. [December 1, 2023 Order in Case No. U-21297, p 375.]

Accordingly, the Company submitted its IRM Year 1 Investment Plan to stakeholders on February 7, 2024, and presented the plan during a stakeholder forum on February 23, 2024 (Foley, 2T 117).

The Company now proposes to extend the IRM through calendar years 2026 and 2027, with two adjustments to the capital programs previously authorized for IRM treatment:

1. Starting in 2026, Pole and Pole Top Maintenance and Modernization (PTMM) would be authorized for IRM treatment (Foley, 2T 118; Elliott Andahazy, 4T 910-11; Exhibit A-33, Schedule X1); and

2. Starting in 2026, the scope of "4.8 kV Circuit Automation" would be modified to "Distribution Automation." This change reflects the Company's strategy to fully automate the distribution grid to provide safety and reliability benefits to customers (Foley, 2T 118; Hartwick, 4T 634, 642-44).

The level of investment and in-service levels for 2026 and 2027 for each program in each IRM Plan Year is outlined in Exhibit A-33, Schedule X1, and summarized in Table 1 at Foley, 2T 119. The Company does not propose any modifications to the annual planning process, annual reconciliation process, or underlying mechanics of the previously approved IRM (Foley, 2T 119; Deol, 5T 1136).

Company witness Vangilder calculated the IRM revenue requirement (Vangilder, 6T 2818-21; Exhibit A-33, Schedule X4). Company witness Maroun allocated the IRM revenue requirement to the various voltage classes (Maroun, 6T 2774-76; Exhibit A-33, Schedule X6). Company witness Willis calculated IRM surcharges consistent with overall distribution rate design (Willis, 6T 2613; Exhibit A-33, Schedule X7).

The Company's proposed total investment for 2026 ($530 million) is similar to the Company's proposal for 2026 in Case No. U-21297 ($532.7 million), but the investment mix is different, with increasing emphasis on Distribution Automation (as indicated above) and PTMM

(Foley, 2T 120; Hartwick, 4T 634; Exhibit A-33, Schedule X1). Company witness Elliott Andahazy further explained that the Company proposes IRM treatment for capital investments of $150 million in 2026, and $200 million in 2027 in the PTMM program (Exhibit A-33, Schedule X1, line 7). The PTMM program should be added to the IRM because it meets the three screening criteria that the Company used to identify capital programs for IRM treatment: (1) critical to customer safety, reliability, and/or resiliency, (2) sufficient size and duration, and (3) well-understood scope (Elliott Andahazy, 4T 910-11).

The Company also proposes an extension to ensure the IRM's continued and efficient operation while pending Case Nos. U-21400 (related to Performance Based Ratemaking (PBR)) and U-21305 (related to the Company's Distribution System Audit) can progress and ultimately conclude. Absent an extension granted in this case, the existing IRM will cease at the end of 2025, and could only be re-established through a Commission order in a future case. Thus, for example, the Company would not submit an IRM Investment Plan for 2026, which would otherwise (if the IRM were extended) be due no later than August 31, 2025. Such starting and stopping of the IRM and its associated processes could lead to inefficiencies, and reduce the ability to improve upon the process through stakeholder feedback. The proposed extension is important to ensure that the customer and stakeholder benefits realized through the IRM do not lapse (Foley, 2T 120-22).

The Company also acknowledges and supports the Commission's desire to incorporate potential insights from Case Nos. U-21400 and U-21305 into future iterations of the IRM (as indicated in the December 1, 2023 Order in Case No. U-21297, p 289, quoted above). The Company plans to propose a PBR mechanism in its first general rate case after Case No. U-21400 concludes. The Company believes that a general rate case is the most appropriate venue to establish PBR, which is also consistent with Staff's December 19, 2023 status report in Case No. U-21400. That filing could consider PBR together with a potential future IRM proposal (Foley, 2T 121-25).

The Company's proposed two-year IRM extension is appropriate to (1) avoid a lapse in the IRM and its associated benefits, (2) provide greater certainty related to use of the IRM as a regulatory mechanism, and (3) maintain the ability to incorporate findings from Case Nos. U-21400 and U-21305 into future iterations of the IRM. A one-year extension would leave continuing uncertainty, and limit the ability for effective long-term planning. To make the IRM successful, there must be robust, transparent, and repeatable processes in place that give all stakeholders confidence that the IRM is working as planned, and the intended benefits are being realized (Foley, 2T 126-27, 155).

Staff did not support extending the IRM through 2027, reasoning in part that "Staff does not want to have the Company locked into spending specific amounts" pending the results of Case Nos. U-21305 and U-21400 (Evans, 6T 5235). The Company disagrees because adjustments to 2026 and/or 2027 IRM authorization could be made in future rate cases, if IRM authorization for those years is granted in this case. This approach, which would potentially update the amount authorized for IRM treatment mid-year, is preferable to allowing the IRM to lapse at the end of 2025. The Company also has concerns about how a lapse in the IRM could be accommodated. Staff suggested the filing of "partial year 2026 and likely calendar year 2027 IRM plans" in December 2025, which would be in the middle of a rate case that Staff contemplates could be filed in mid-2025 (Evans, 6T 5236). Such an approach would be inefficient because the Company would need to prepare the plan assuming a certain level of future IRM authorization, and Staff and intervenors would need to invest significant resources to review the plan, before the Commission issues its Order, potentially differing from the assumptions and requiring further revisions and review (Foley, 2T 126, 154-55).

ABATE recommended that the Commission "should only permit DTE to add a Year 3 to its distribution IRM and only for the existing authorized categories. . . for a total investment amount for Year 3 of $275.0 million, reasoning in part that the "IRM is still in its infancy" (Dauphinais, 6T

3381). The Company acknowledges that the IRM is still in its early stages, but this is not a compelling reason to limit the IRM's growth if the investments are otherwise warranted, which they are as discussed above. Also as indicated above in response to Staff, authorizing an extension of the IRM would not preclude the Commission from ordering adjustments in future rate cases once pending Case Nos. U-21305 and U-21400 have concluded (Foley, 2T 157-58).

AG-MN witness Alvarez opposed the Company's proposed IRM extension, admittedly echoing his anti-rider arguments from Case No. U-21297 (Alvarez, 6T 3943). There is nothing new to suggest that the Commission erred when it authorized the IRM, so the Company simply notes its disagreement and that the IRM is well supported, as demonstrated by the Company's filings in Case No. U-21297.

Witness Alvarez further contended that the preview and reconciliation ordered in Case No. U-21297 "offer little more than lip service to capital spending governance" (Alvarez, 6t 3947). The Company disagrees because the contention is unfounded (Foley, 2T 160-61). The Commission stated:

> The filing of the IRM Investment Plan at least four months prior to the start of each plan year will allow for a more meaningful review by both the Staff and other interested stakeholders. Further, the submission of the plan to all intervening parties, along with providing a forum for interested parties to raise concerns, will allow for additional collaboration and input into the proposed investments.
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> In addition to plan review, a contested reconciliation process will provide additional opportunities for input from interested parties. Further, developing a record in a contested proceeding will provide even greater transparency and opportunity for review of the reasonableness and prudence of the company's expenditures, as well as accept input to address equity concerns such as those raised by the DAAOs to avoid racialized disparities in service. [December 1, 2023 Order in Case No. U-21297, pp 289-90.]

Therefore, the Company maintains its original position to extend the IRM though 2027 at the proposed investment levels. If the Commission does not find this appropriate, however, then the

Commission should at least approve a one-year extension at the investment levels authorized previously for 2025 (IRM year 2). This is similar to ABATE's recommendation, and represents a better, more efficient path forward than allowing the IRM to lapse at the end of 2025. It is also valuable for the Company to have clear visibility and certainty of the work it can execute in a specific year well in advance of project execution, so that it can procure the appropriate resources, obtain necessary permits, and otherwise ensure efficient and timely execution (Foley, 2T 155-56, 158).

Walmart recommended:

> If the Commission approves extending the IRM, it should also require the Company to file a base rate case at the earliest possible date when assets can be included in the Company's test year. Additionally, the Commission should deny recovery of any costs exceeding what was approved in the Company's last rate case for IRM plan years 2024 and 2025, requiring the Company to recover these additional costs through base rates instead. [Perry, 6T 4740.]

The Company disagrees because existing processes already address Walmart's indicated concerns. The IRM includes an annual reconciliation that addresses the prudency of IRM investments made in the previous year. Also, as the Company proposed and the Commission ordered, the Company cannot unilaterally increase the size of the IRM surcharge for 2024 and 2025. Therefore, Walmart's recommendations should be rejected (Foley, 2T 162-63).

The Company's extension proposal for 2026 and 2027 does not affect the IRM authorization that the Commission granted in Case No. U-21297; however, the Company is also agreeable to increasing the amount of capital authorized for IRM treatment in 2025 as a way to further increase the associated benefits (e.g., increasing the certainty of investment for intended purposes, with any under-investment triggering a refund for customers). The Company identified the following four areas for additional IRM investment in 2025:

1. Distribution Automation - $125.6 million (Foley, 2T 128; Hartwick, 4T 634; Exhibit A-12, Schedule B5.4, page 17, line 2);

2. PTMM - $121.0 million (Foley, 2T 128; Elliott Andahazy, 4T910-911; Exhibit A-12, Schedule B5.4, page 13, line 13);

3. 4.8 kV Hardening - $125.0 million (Foley, 2T 128; Elliott Andahazy 4T912-932; Exhibit A-12, Schedule 5.4, page 13, line 12); and

4. Frequent Outage Program (CEMI) - $62.5 million (Foley, 2T 128; Elliott Andahazy, 4T982-987; Exhibit A-12, Schedule B5.4, page 13, line 15).

If the Commission were to approve a 2025 IRM increase, then the Company's request for recovery of 2025 capital expenditures through base rates could be reduced by an amount equal to the additional IRM authorization (Foley, 2T 118, 127-28).

In summary, the Company's proposed Distribution IRM extension and expansion should be approved along with the Company's proposed IRM surcharges included in Exhibit A-33, Schedule X7.

B. Storm Restoration Cost Sharing Mechanism (SRCSM)

As discussed above in section VII. C. 5, Distribution O&M expenses include $64.5 million of storm restoration O&M expenses, which were calculated based on a five-year trailing average (historical test year and preceding four years) adjusted for inflation, which is consistent with past cases (Foley, 2T 128-29; Kryscynski, 3T 321; Exhibit A-13, Schedule C5.6, page 2, lines 1-8).

The current approach to storm restoration O&M expense recovery puts both customers and the Company at risk of an over-recovery or an under-recovery, because it does not address the uncertainty and variability of those expenses in any given year. Year-over-year changes in actual storm restoration O&M expenses from 2018-2022 ranged from a 17% decrease between 2021 and 2022, to an 85% increase between 2020 and 2021 (reflected by Figure 10 at Foley, 2T 130). Those expenses are impacted by the frequency and duration of extreme weather events. There is a clear trend toward more extreme weather in the Upper Midwest (including Michigan), as well as

significant variation from year to year. The amount of extreme weather experienced by the Company cannot be accurately predicted in advance, so storm restoration O&M expenses will remain uncertain and volatile (Foley, 2T 129-32).

To address this issue, the Company proposes that the Commission authorize a Storm Restoration Cost Sharing Mechanism (SRCSM), which would become effective at the start of the projected test year (January 1, 2025), and operate as follows:

1. The five-year trailing average methodology would continue to be used to calculate the projected expenses, and they would continue to be authorized for recovery though base rates as indicated in section VII. C. 5 (Distribution O&M).
2. At the conclusion of each calendar year, actual storm restoration O&M expenses would be compared to the amount authorized for recovery in base rates (if the authorized amount changes mid-year, then the authorized recovery amount would be calculated on a prorated basis);
3. Any difference between actual and authorized storm restoration O&M expenses would be shared equally between the Company and its customers (If actual expenses are less than the amount authorized for recovery, then the Company would return 50% of the difference to customers by recording that amount as a regulatory liability. If actual expenses are more than the amount authorized for recovery, then the Company would recover 50% of the difference from customers by recording the amount as a regulatory asset); and

4. Regulatory assets and/or liabilities would accumulate until a subsequent general rate case where any net regulatory asset or liability would be addressed (Foley, 2T 132-33).[123]

The Company's proposal for the equal sharing of costs is responsive to the Commission's guidance from the March 1, 2024 Order in Case No. U-21389 in which it declined to adopt Consumers' proposed Symmetric Performance Incentive Mechanism (SPIM), noting concerns that the SPIM's proposed 10% deadband would not provide sufficient incentives to control costs. In contrast, the Company's proposal ensures that the Company has a strong incentive to control costs regardless of the level of actual costs for any given year. Specifically, if actual costs are greater than projected, then the Company is incentivized to control costs because it must absorb 50 cents of every incremental dollar that is spent. If actual costs are less than projected, then the Company is incentivized to control costs because it is allowed to retain 50 cents of every incremental dollar that is saved (Foley, 2T 134-36).

Staff did not support the SRCSM "because 1) Staff is supporting the full-service restoration expense for the test year; 2) the Commission rejected similar mechanisms in prior cases U-20963, U-20697, and U-21389; and 3) Staff would like to see results from the third-party audit to further determine cost savings in storm restoration expenses" (Duell, 6T 5149).

The Company appreciates Staff's support for the projected test year storm restoration expense, but maintains that its proposed SRCSM is justified to enhance the current process, which puts both customers and the Company at financial risk because it does not address the uncertainty and variability of storm restoration O&M expenses in any given year. The Company also disagrees

[123] The Company requests to use accounts 182.3 (Other Regulatory Assets) and 254 (Other Regulatory Liabilities) to record the refundable or recoverable portion of any difference between actual storm costs and the base amount approved in this case (Uzenski, 6T 1558).

that the Commission rejected similar mechanisms in case Nos. U-20963, U-20697, and U-21389. Those cases concerned a proposed *cost tracker*. The Company proposes a *cost sharing mechanism*, which is fundamentally different. Staff's indicated concern about the distribution audit in Case No. U-21305 is also misplaced because the SRCSM is designed to address the uncertainty and volatility of storm restoration O&M costs, and would not preclude the Company from using the audit's findings to pursue cost savings. Such cost savings would ultimately be incorporated into forecasts of future storm restoration O&M costs, but lack relevance to establishing the SRCSM to immediately improve upon the current approach to O&M cost recovery (Foley, 2T 129-32, 164-65).

Staff further suggested that "[c]ustomers may never see a benefit" from the SRCSM (Duell, 6T 5149). The indicated concern is overstated because that situation would happen only if actual storm restoration costs were always above projected costs. These costs are volatile as indicated above, so Staff's suggested continuous one-sided outcome is unlikely (Foley, 2T 165). Finally, Staff suggested that the Company's proposal "dulls" its incentives to control costs (Duell, 6T 5149). The Company maintains that the 50% sharing of costs that deviate from projections maintains a significant incentive to control costs. The SRCSM would also better protect customers and the Company from financial risk, as discussed above. Therefore, the Company's proposed SRCSM should be approved (Foley, 2T 65-66).

CUB-MN and Ann Arbor also opposed the SRCSM for reasons that cannot withstand analysis. CUB-MN witness Denzler asserted that the SRCSM "skews the share of risk significantly in favor of the Company, at the expense of ratepayers" (6T 3769). To the contrary, storm restoration O&M costs are uncertain and volatile as discussed above. The SRCSM would protect both customers and the Company through the equal sharing of costs that deviate from projections (Foley, 2T 129, 167-68).

CUB-MN witness Denzler further asserted that the SRCSM "would create a financial incentive for the Company to extend the duration of Storms and perform additional work under the Storm umbrella as it would be 50% cheaper than performed after Storm-close" (6T 3772). This assertion indicates a fundamental misunderstanding of how storm cost accounting works. Storms are well-defined events that have an identifiable start, end, and population of impacted customers. The Company cannot elect to extend the duration of a storm to increase cost recovery as Mr. Denzler suggested (Foley, 2T 168).

CUB-MN witness Denzler further asserted that "the Company has stated there is no current standard, other than field crew judgment, on when to repair versus replace field assets, and has not conducted a cost/benefit analysis to support any such decisions. Particularly with the absence of any objective standard, the Company may alter Storm decision making to take advantage of this new cost share mechanism" (Denzler, 6T 3773, citing a discovery response indicating that field crews decide whether to repair or replace equipment based on their experience and judgment).

To the contrary, field crews using their experience and judgment would not somehow enable the Company to take advantage of its proposed cost sharing mechanism (and it is unclear how Mr. Denzler even connected the subjects to somehow make their allegation). Instead, the Company's field personnel are highly trained and experienced skilled trades workers. They prioritize employee and public safety, and speed of power restoration during storms, and make decisions between repairing and replacing based on these factors. It is reasonable to rely on the professional judgment of trained experts, who work at the point of activity, and are therefore best equipped to understand the condition of damaged assets in the field and whether they can (or cannot) be repaired (Hill, 6T 3088-89).

There is similarly no basis for Ann Arbor witness Stults' contention that the SRCSM would motivate the Company to "play a shell game with capital recovery for repairs" (6T 4260). The

SRCSM does not concern capital cost recovery. It is just a mechanism to address the uncertainty and volatility of certain O&M expenses (Foley, 2T 171).

Ann Arbor witness Stults also missed the mark in asserting that the SRCSM would "reward the Company for projecting very high estimates of storm restoration costs, so it appears to 'underspend' its target" (6T 4260). The current approach to projecting these expense is formulaic based on historical average spending adjusted for inflation.[124] The Company cannot simply project "very high estimates" as suggested (Foley, 2T 171).

Witness Stults asserted that the SRCSM "would allow the Company to keep half of the savings that result from coming up to normal maintenance standards. It would be unreasonable for the Company not to pass on these savings on to the ratepayers who funded the more resilient grid . . . ." (6T 4261). The indicated position neglects that the SRCSM would return half of the savings to customers, in contrast to the current approach that allows the Company to keep *all* savings if actual storm restoration O&M expenses are less than projected. Also, if the Company reduces storm restoration O&M costs over time as Ann Arbor suggested, then customers would fully capture these savings through lower projected costs that are recovered through rates (Foley, 2T 171-72).

CUB-MN witness Denzler recommended that the Commission "order DTE to develop Storm performance criteria that include outage restoration, estimate accuracy, resource productivity, and financial responsibility specific to Storm scenarios and tie-bar financial recovery of excess Storm restoration costs to the Company's performance in these areas" (Denzler, 6T 3774. See also 6T 3780). The Company disagrees because these matters are already addressed in (1) the Service Quality and Reliability Standards (SQRS), which sets standards of service related to the

[124] The Company calculated $64.5 million of storm restoration O&M expenses based on a five-year trailing average (historical test year and preceding four years) adjusted for inflation, which is consistent with past cases (Foley, 2T 128-29; Kryscynski, 3T 321; Exhibit A-13, Schedule C5.6, page 2, lines 1-8).

frequency and duration of storm-related outages, and (2) pending Case No. U-21400 relating to financial incentives and disincentives (Foley, 2T 169; Hill, 6T 3090).

Witness Denzler further recommended that if the Commission approves the SRCSM, then it should "reduce the rate of return it authorizes on those costs" (Denzler, 6T 3774). This recommendation lacks merit and relevance because the SRCSM addresses only storm restoration O&M expenses, on which there is no "rate of return," so there is nothing to reduce (Foley, 2T 169).

Therefore, the proposed SRCSM should be approved, and contrary and additional proposals should be rejected.

C. Electric Vehicle Pilots - Charging Forward

The Commission previously approved the Company's proposed Charging Forward program regarding electric vehicles (EVs), with some modifications, stating in part:

> [T]the Commission finds that DTE Electric is authorized to create a regulatory asset to recognize deferred EV program costs with the amortization of those costs over five years beginning the year after the costs are incurred. Further, the Commission authorizes the company to include recovery of the resulting amortization expense in rates and include the deferred net unamortized balance of EV program costs in rate base. However, the program costs will not actually be recovered until they have undergone a future reasonableness and prudence review in a rate case. [May 2, 2019 Order in Case No. U-20162, p 115.]

The Company provided an update on Charging Forward in Case No. U-20561, where the Commission concluded:

> Consistent with the May 2 [2019 Order in Case No. U-20162], the Commission agrees with the ALJ that the regulatory asset and capital expense should be approved for only the actual and reviewed expenses. Going forward, DTE Electric is authorized to begin the five-year amortization concurrent with review and approval in a rate case in lieu of amortization over five years beginning the year after the costs are incurred. [May 8, 2020 Order in Case No. U-20561, pp 165-66.]

To build on momentum of Charging Forward's fleet component and avoid any gaps in available funding to support fleet electrification, on December 3, 2020, DTE Electric filed an application

seeking *ex parte* approval of regulatory asset treatment and deferral authority for costs associated with Phase Two of its Charging Forward pilot program (Phase Two or eFleets). The Commission approved, stating in part:

> [T]he Commission concludes that DTE Electric's Phase Two proposal is reasonable and in the public interest as it will develop a better understanding regarding how C&I customers are incentivized to make the transition to clean EV technology, how the increased electrical load associated with EVs impacts electrical system usage and grid requirements, as well as the expected operational impacts of a wider commercial EV rollout. As such, the Commission authorizes DTE Electric to create a regulatory asset, not to exceed $10.3 million, to recognize deferred Phase Two program costs with the amortization of those costs over five years beginning the year after the costs are incurred. [March 19, 2021 Order in Case No. U-20935, pp. 4-5.]

In Case No. U-20836, the Company proposed a Charging Forward Expansion, which involved extending existing elements based on lessons learned, and introducing new elements to address identified gaps, including a number of new pilots. The parties agreed with many of the proposed changes. The Commission addressed disputed issues (November 18, 2022 Order in Case No. U-20836 Order, pp 320-51).

Most recently, the Commission again addressed various issues, and approved funding through 2024 (December 1, 2023 Order in Case No. U-21297, pp 256-80).

Against this backdrop, Company witness Bennett provided an update explaining and supporting the costs for various Charging Forward programs and pilots (Bennett 6T 1922-30; Exhibit A-12, Schedule B5.9). Total program costs were $6.0 million in 2022, and are projected to be $39.566 million for the 24 months ending December 31, 2024, and $28.480 million for the projected test year (Bennett, 6T 1924; Exhibit A-12, Schedule B5.9, line 24, columns (b), (e) and (f)). A complete status update of Charging Forward and justification for its components' costs is set forth in Exhibit A-29, Schedule T1 (Charging Forward's 4th Annual Status Report, which the Company filed in August 2023 in Case No. U-20162).

The Company also seeks Transportation Electrification Plan (TEP) cost recovery and accounting treatment for 2025 as summarized in Table 14 at Bennett, 6T 1977 (Bennett, 6T 1976-79). As further discussed below, the TEP continues some aspects of existing programs.

1. Transportation Electrification Plan (TEP) Proposal

In Case No. U-20836, the Commission largely approved the Company's proposed Charging Forward Expansion, and stated:

> The Commission further directs DTE Electric to prepare and submit, with its next rate case, a full scale, well-developed, permanent Charging Forward proposal that includes a BCA [benefit-cost analysis]. The Commission is not persuaded that all the Company's pre-existing pilots lack sufficient development to transition to a permanent program or that the EV market conditions are evolving too quickly for the company to respond; however, should that be the case, the company may submit with the rate case its reasons for the delay in transition from pilot to permanent program and a proposal for a different timeline for the Commission's consideration. [November 18, 2022 Order in Case No. U-20836, p 351.]

In Case No. U-21297, the Company explained that it was beginning to transition to permanent programs, and working on a detailed TEP, including detailed program design, investment levels, and benefit-cost analyses (e.g., U-21297 Peterson, 4T 710, 713). The PFD essentially found that the Company's BCA was sufficient for purposes of that case (U-21297, PFD, pp 690-91), and agreed with the Company that various intervenor recommendations for what the Company's TEP should contain or consider were premature, but the Company should hold at least two stakeholder meetings (U-21297 PFD, pp 696, 698-99). The Commission agreed (December 1, 2023 Order in Case No. U-21297, p 279).

2. Background and Approach

Ms. Bennett explained that the Company spent the last year and a half developing a comprehensive TEP with robust analyses and careful evaluation of the role of the utility, along with in-depth benchmarking and stakeholder consultation (Bennett, 6T 1931). She also provided further

details regarding the Company's overall vision, guiding principles, and approach to developing its TEP (6T 1931-32), as well as the nature of the Company's benchmarking process, and the findings from that benchmarking (6T 1932-40).

There are currently almost 46,000 EVs registered in Southeast Michigan. The Company forecasts that this will increase to 326,000 by 2028, which is the TEP's timeframe. This equates to approximately 238,000 incremental chargers being needed in DTE Electric's service territory over the four-year TEP time horizon. More than 80% of the estimated chargers needed to support the forecasted EV adoption from 2025 through 2028 are projected to be at single-family homes, with the majority of those chargers being Level 2 chargers (Bennett, 6T 1940-45). The approximately 238,000 incremental chargers needed over the four-year TEP time horizon will require nearly $1.9 billion of infrastructure investment, funded by a mix of public, private, government, and utility sources (Bennett, 6T 1945-46).

The Company appreciates the general support that it has received, and in response to various suggestions, agrees to provide additional information and consider various proposals (Bennett, 6T 1993-96, 2006, 2009-11). The following discussion focuses on indicated disagreements, in the context of the Company's proposals.

MEIU witness Sherman suggested that the Company's EV forecast is likely too low due the EPA's recently-adopted vehicle emissions standards (Sherman, 6T 4062). The Company disagrees because the EPA is just one source of data, and the Company's forecast relies on multiple sources. Witness Sherman's reliance on a 2032 expectation is also misplaced as beyond the time period for planning in this case, as well as the TEP which goes through 2028 (Bennett, 6T 1997).

AG Witness Coppola did not address the Company's forecast directly, but suggested that the market for EVs is less than what the Company projects, so the Company need not make certain investments to accommodate future EV growth (Coppola, 6T 3608-3609). Based on these

propositions, he recommended that 2024 and 2025 capital expenditures for utility make ready (UMR) associated with EVs be "set at the 2023 amount plus inflation," and "the Commission remove the difference of $3,734,000 for 2024 and $10,173,000 for 2025 from the Company's capital expenditures" (Coppola, 6T 3609), and "consistent with my recommendations in the Utility Make Ready testimony, I propose that the forecasted capital expenditures in Schedule B9 be reduced by 45% for 2024 and 2025. This means a reduction in capital expenditures of $6,979,000 for 2024 and $2,295,000 for 2025" (Coppola, 6T 3638).

The Company disagrees because there is ample evidence to support its EV projections. For example, year-to-date EV sales experienced their highest level in Michigan, demonstrating continued growth in the EV market (Exhibit A-49, Schedule NN5). EV registrations through the first five months of 2024 are on track with the Company's projection that over 22,000 new electric vehicles will enter its service area in 2024. The Company's projections therefore reflect the realized pace of EV adoption. They are also conservative compared to the Michigan Healthy Climate Plan's target of 50% of new vehicle sales being electric by 2030, as well as MEIU witness Sherman's suggestions. Therefore, the AG's proposed disallowances should be rejected (Bennett, 6T 1998-2001).

AG-MN witness Stephens recommended an independent expert analysis of EV adoption forecasts (Stephens, 6T 4006). The Company strongly disagrees because it based its forecast analysis on expert external forecasts that were conducted by reputable organizations with extensive experience and expertise in the field. Conducting an independent expert analysis would require significant time and money that could be better spent on infrastructure development, customer education, and other initiatives that support EV adoption (Bennett, 6T 2001).

The Company engaged stakeholders by, among other things, hosting annual stakeholder discussions and submitting quarterly and annual status reports in the Case No. U-20162 docket. The

Company also implemented a stakeholder engagement process including a series of stakeholder webinars and surveys to provide transparency and obtain feedback to ensure that the TEP balances the diverse interests of stakeholders, who sometimes agreed with each other, and sometimes disagreed (Bennett, 6T 1948-51).

Stakeholder feedback also helped shape the TEP. In accordance with the Company's guiding principles, DTE Electric had already envisioned supporting and accelerating EV adoption by facilitating charger deployment while ensuring affordability benefits for all DTE Electric customers, and promoting equity by focusing on low-income customers and disadvantaged communities, which are things that TEP stakeholders valued as well. After receiving feedback from stakeholders, DTE Electric also decided (1) not to waive CIAC beyond revenue credits from existing line extension policy,[125] (2) to use its own EV forecasting methodology to determine charging infrastructure needs, and (3) not to include utility-owned pole-mounted chargers with this initial TEP. The Company will also continue to engage key stakeholders during the TEP timeframe by continuing to provide Annual Status Reports for its TEP programs (Bennett, 6T 1951-52, 1968).

The Company's framework to develop the TEP included three primary cost categories for charger installation (utility make-ready, customer make-ready, and EV chargers). The Company also refined the five primary customer segments (single-family homes, multi-unit dwellings, public, fleet, and workplace) into more granular sub-segments (Bennett, 6T 1952-54).

3. TEP Portfolio Proposal

The proposed TEP rebate programs (summarized at Table 9 at Bennett, 6T 1955) achieve the Company's guiding principles by facilitating charger deployment while maintaining overall

[125] The Company proposes to delete the Charging Forward CIAC waiver in section C6.1(16). (Bennett, 6T 1968; Willis, 6T 2614-15).

affordability benefits for all DTE Electric customers, improving economics of electrification in the near-term, and promoting equity with a focus on low-income customers and disadvantaged communities. The public (on-route charging) segment makes up the biggest category of investment (30%), partly due to inherently high costs (expensive hardware and high installation costs driven by high-voltage wiring) and partly in response to stakeholders. Stakeholders generally indicated high levels of satisfaction with the Company's preview of its TEP programs, but the preview did not include the non-DAC/Rural DCFC customer sub-segment. The greatest impact that stakeholder feedback had on the final TEP was the inclusion of this subsegment (Bennett, 6T 1955-57, 1963).

Ms. Bennett further explained that stakeholders ranked all of the public charging subsegments as the most important for utility action because the availability of public charging is critical to reducing range anxiety, which is a key barrier to EV adoption. The Company proposes to support on-route public fast charging by offering a rebate of $70,000 per on-route DCFC in disadvantaged communities and rural areas, and $50,000 per on-route DCFC in other areas. To manage affordability impacts to its customers, the Company proposes to support 35% of the forecasted on-route public charger deployment and rural on-route subsegment, and 35% in the other on-route areas (Bennett, 6T 1963).

Electrify America witness Davis asserted that "Electrify America is strongly opposed to the 97% uptime requirements associated with DTE's Proposed on-route DCFC rebates," indicating concerns about the information being competitively sensitive (Davis, 6T 4767). The Company believes that charger uptime has to be measured to ensure ratepayer funding is utilized most effectively, and the 97% uptime target appropriately aligns with Federal Highway Administration requirements (Bennett, 6T 2005-2006). The 97% uptime requirement was also discussed extensively in Case No. U-20836, where the Commission concluded:

> Therefore, the Commission adopts a 97% charger uptime for participants in this pilot as it is currently proposed by the Federal Highway Administration's (FHA's) NEVI program guidelines. Should the FHA ultimately revise or update its guidance on uptime requirements upon issuance of the final NEVI rule, the Commission

> would then be open to revisiting these guidelines and reserves the right to modify this charger uptime requirement to maintain consistency with federal guidelines. [November 18, 2022, Order in Case No. U-20836, p 331.]

Electrify America (Davis, 6T 4769), EVgo (Stegall, 6T 3300), and MEIU (Sherman, 6T 4090) proposed to eliminate the requirement that public DCFC must be "on-route" locations within one mile of a major throughway to qualify for a rebate and proposed instead to extend these rebates to all public DCFC locations.

The Company disagrees because it is committed to supporting 35% of the forecasted on-route public charger deployment. The funding also aligns with stakeholders' priorities. The provision of fast, reliable, on-route charging within one mile of a major throughway exit is crucial to increasing customer confidence in EV charging infrastructure (Bennett, 6T 2006-2007).

The single-family homes segment is another large category of investment (19%). The Company proposes Home Charger Rebates for low-income customers in single-family homes over the TEP timeframe at 100% of the forecasted charger deployments in the Company's service territory. The proposed rebate (calculated at an average of $2,200) would cover the cost of the Level 2 charger and the full cost of the customer's installation. The Company focused its support on the low-income, single-family home subsegment for a number of reasons, including that (1) the cost to install a home charger can be a significant barrier for low-income residential customers, (2) customers need to install a charger at home to obtain the fuel pricing of approximately $1 eGallon equivalent and experience the benefits and features of a dedicated EV charger, (3) customers can face high installation costs due to outdated electrical wiring and/or breaker panels, and (4) the Company received strong stakeholder support for this approach. The Company also lowered the income eligibility threshold to 200% of the federal poverty level, in response to stakeholder feedback (Bennett, 6T 1955, 1957-58).

MEIU proposed that the income-qualified threshold for the residential customer rebates program be set at 400% of the federal poverty level (Sherman, 6T 4085). Ann Arbor proposed 300% (Stults, 6T 4272). The Company had envisioned 400%, but some stakeholders indicated that this

was too high, so the Company lowered the income-eligibility threshold to 200%, which also aligns with the threshold for other DTE low-income programs. Since the program was developed with stakeholder feedback in mind, the Company does not deem it appropriate to modify the threshold without further participant data (Bennett, 6T 1958, 2007-2008).

MEIU further suggested that customers should be allowed to attest to their income (Sherman, 6T 4085). The Company disagrees because in its experience administering the EV Rebate program, many customers do not necessarily pay close attention to the eligibility criteria, but instead rely on the Company to validate their eligibility. There is also a risk that individuals could falsely self-attest, taking resources away from those who truly need them. Although self-attestation might seem like it would reduce administrative burdens, the administrative work could also increase due to fraud and its consequences. To ensure the correct segment of customers benefits from this program, it is necessary to have checks and balances in place to administer the program accurately (Bennett, 6T 2008).

The Company proposes two programs to support the multi-unit dwelling (MUD) segment. First, the Company proposes rebates for qualified low-income MUDs at about 90% of the forecasted MUD charger deployments over the TEP timeframe. The proposed income-qualified Business Charger Rebate would cover the cost of the Level 2 charger and the full cost of installation. The average rebate is calculated at $14,000 per charger. The Company also proposes support for all other MUDs at about 45% of the forecasted MUD charger deployments over the TEP timeframe to cover the cost of the charger and a portion of the installation. The proposed revised Business Charger Rebate would be $5,000 and would cover the cost of the Level 2 charger. The Company proposes support for this segment for reasons similar to those indicated above regarding the single-family home segment, as well as overcoming cost and motivation issues for landlords to install EV chargers, benchmarking that indicates MUDs are receiving unique attention in other utility TEPs, and stakeholder support for the low-income MUD housing segment (Bennett, 6T 1955, 1959-60).

The Company proposes to support the fleet charging segment by continuing its eFleet

Charger Rebate program for both school and transit buses with a rebate of $70,000 per DCFC. The Company proposes to support 100% of the transit bus charger subsegment over the TEP timeframe, and 30% of the forecasted school bus chargers needed while interest and affordability evolve. The Company also proposes to continue offering a $2,500 eFleet Charger Rebate for all fleet owners installing a Level 2 charger (supporting 90% of the forecasted charger deployments in this subsegment), and to continue offering up to a $70,000 eFleet Charger Rebate for DCFCs for approximately 30% of the forecasted charger deployments (Bennett, 6T 1965-66).

Staff proposed to disallow $8,000,000 for the Business and eFleet Charger Rebates program (Freeman, 6T 5087-88). The Company disagrees because the program aims to support various segments, with an increase in proposed 2025 rebate amounts per segment compared to 2024. Such a funding reduction would result in approximately 600 fewer rebates across all segments of the TEP (Bennett, 6T 2003; Exhibit A-49, Schedule NN1).

Staff proposed to disallow $1,000,000 for the Residential Customer Rebate program (Freeman, 6T 5088-89). The Company disagrees because such a funding reduction would result in approximately 455 fewer rebates being available to support EV adoption by low-income single family homes (Bennett, 6T 2003-2004; Exhibit A-49, Schedule NN1).

MNSC witness Jester recommended that the Company "prepare a supplement to its Transportation Electrification Plan that addresses grid integration of electric vehicle charging by providing a forecast of load profiles at line transformers, circuit feeder origination at the substation, and generation when electric vehicle charging is combined with existing loads at various levels of electric vehicle adoption and by also providing an analysis of load net of renewable generation at various levels of electric vehicle adoption with Michigan attaining 50% renewables, 60% renewables, and 80% renewables" (Jester, 6T 3808-3809), plus "include full 8760-hour annual load profiles for electric vehicle charging amongst the metrics . . . ." (Jester, 6T 3815).

The Company disagrees due to challenges in data availability, data cleaning efforts, and potential misunderstanding of the data. For example, the Company simply does not know certain

information about public chargers, so the Company cannot commit to the requested granular and specific data (Bennett, 6T 2004).

MEIU recommended making rebates available to public Level 2 chargers (Sherman, 6T 4091-93). The Company disagrees because site hosts considering the installation of Level 2 chargers will find the economics of deployment less challenging. These chargers utilize the standard 240V electrical supply, which many businesses already have in place, making electrification cost effective. Businesses also have additional motivations for installation, such as the potential for increased foot traffic (Bennett, 6T 2010).

As indicated above, the Company decided not to waive CIAC beyond revenue credits from existing line extension policy, which aligns with feedback from stakeholders, and will align the TEP with the Company's rate book.[126] MEIU (Sherman, 6T 4057-58) and Electrify America (Shah, 6T 4788) offer different views. The Company maintains its position to align the CIAC policy for EV customers with other connections because this promotes fairness and equity, ensuring all customers contribute to the infrastructure they use, while keeping rates affordable for all customers. The CIAC waiver was initially designed to stimulate interest and growth in EV adoption. Over the five years that the Company has been running the Charging Forward program, the CIAC waiver has played a minimal to non-existent role for the participating site hosts (Exhibit A-49, Schedule NN2). The need for a CIAC waiver is also further diminishing as the EV market matures and the costs of EV infrastructure are spread across a larger number of users. Therefore, the CIAC waiver is no longer appropriate (Bennett, 6T 1968, 2011-13).

4. Benefit-Cost Analysis (BCA)

Overall, the TEP portfolio-level BCA has a net present value (NPV) revenue requirement of $56 million. In other words, there are a range of values at the segment level (reflected in Table

[126] The Company proposes to delete the Charging Forward CIAC waiver in section C6.1(16). (Bennett, 6T 1968; Willis, 6T 2614-15).

13 at Bennett, 6T 1974), but overall the TEP is projected to provide $56 million of rate relief for DTE Electric customers. Also, as shown in Figure 6 at Bennett, 6T 1975, the annual revenue requirement initially applies rate pressure, but the TEP begins providing rate relief in 2033, increasing to a maximum in 2064, so the proposed rebates are beneficial to customers in the long run (Bennett, 6T 1974-75). Company witness Bennett also explained and supported the key assumptions underlying the BCA analysis (6T 1970-73), and that the estimated $56 million in rate relief is conservative for several reasons (6T 1975-76).

MEIU witness Sherman recommended changes to the Company's BCA based on three criticisms: (1) it is overly conservative in a number of its assumptions; (2) it incorrectly assumes a constant utilization rate over time for all types of chargers; and (3) it fails to account for societal benefits from transportation electrification (Sherman, 6T 4066-82).

The Company maintains that its BCA is appropriate, so witness Sherman's proposed changes to the BCA should be rejected. Company witness Bennett responded in detail regarding each criticism, noting for example that (1) the Company's BCA is intentionally, and appropriately, conservative to ensure that even if actual benefits are lower than expected, the investment will still be justified, and (2) adding additional societal benefits such as greenhouse gas and criteria pollutant emissions reductions would not be appropriate for a number of reasons, including difficulties in calculating the benefits and attributing them to a single company, and uncertainty due to future regulatory changes and other factors that could significantly impact the realization and magnitude of such benefits (Bennett, 6T 2013-15).

The same response generally applies to MNSC witness Jester's suggestions for a broader BCA (Jester, 6T 3813-15). Company witness Bennett explained in part:

> [T]he BCA as presented by DTE Electric provides an appropriately comprehensive, conservative, and realistic assessment of the costs and benefits of its TEP. Therefore, the Company's TEP appropriately supports the proposed levels

> of Company TEP spending. Witness Jester favors a BCA that far exceeds the scope of this case and evaluates a wide variety of matters with, at best, oblique connections to the Company's electric rates. The Company's attribution of only a portion of EV adoption to DTE Electric's TEP is a conservative approach that takes into account the fact that not all EV adoption can be directly attributable to the Company's efforts. This approach avoids overestimating the benefits of the TEP, thereby providing a more realistic assessment of its impact. [Bennett, 6T 2015-16.]

Staff indicated concerns that "it is entirely possible [certain fleet customers] will cause substantial costs that could be borne by other customers," and therefore suggested that customer-specific BCAs should be performed, and rebates should be allowed only for net positive BCAs (Revere, 6T 4961).

The Company disagrees. It is important to consider the portfolio-level benefits that extend beyond the individual customer or fleet segment. Conducting individual BCAs for each fleet customer could also be burdensome and costly, with customers ultimately bearing those costs (Bennett, 6T 2015).

MEIU (Sherman, 6T 4098-99) and Electrify America (Shah, 6T 4786-87) proposed that the Commission extend the Rate Schedule D3 demand charge holiday. The Company disagrees because the Commission previously extended the period from June 1, 2024 to the current June 1, 2026 (December 1, 2023 Order in Case No. U-21297, p 341). Witnesses Sherman and Shaw did not provide any particular evidence that a further extension is necessary. The Company's D3 tariff, with or without the 1,000 kW exemption will continue to serve fast chargers less than 1,000 kW indefinitely, and there is no evidence that the tariff is inhibiting the deployment of fast chargers. The Company has also proposed a primary voltage time of use rate that does not include demand charges (Rate D14, discussed in section X. F. 1 below), which if approved will provide yet another option for charging customers (Willis, 6T 2644-45). Staff similarly opposed extending the demand charge holiday (Krause, 6T 5205).

Therefore, the Company's transportation electrification proposals and requested cost recovery should be approved, and additional and contrary recommendations should be rejected.

D. Advanced Customer Pricing Pilot (ACPP) and 2023 Full TOD Rollout

Company witness Bennett supported ACPP costs relating to Customer Outreach, and Evaluation, Monitoring, and Verification (EM&V). Customer Outreach communicated the transition to full TOD rollout so all residential electric customers were informed that their base rate would be changed to a new TOD rate in March 2023. The Company seeks to recover O&M expenses totaling $2.497 million ($2.044 million for 2022, and $0.453 million for 2023), which were needed because, based on lessons learned from the ACPP pilot, DTE Electric prepared customers for the rate change by sending a series of communications via multiple channels (Bennett, 6T 1984-85; Exhibit A-13, Schedule C5.9.2, line 10). The Company also seeks to recover $0.172 million of O&M expenses related to EM&V (Bennett, 6T 1984; Exhibit A-13, Schedule C5.9.2, column (e). See also, Uzenski 6T 1544-45 and Exhibit A-13, Schedule C5.9.3 regarding the calculation of annual amortization expense for ACPP and TOD regulatory assets).

E. Outage Credits

In Case No. U-20836, the Company proposed that credits paid for outages caused by events outside of the Company's control be deferred for subsequent recovery starting with the final order in that case (See generally, U-20836, Crozier, 7T 2359-2362; Uzenski, 7T 2770). Staff agreed with the Company's deferral proposal, but suggested that only certain types of outages caused by third parties should be compensated (U-20836, Staff Initial Brief pp. 272-273). The Commission directed:

> DTE Electric to work with the Staff toward the full development of the Staff's proposed limited recovery of outage credits. The Commission upholds the company's responsibility to restore electric service to customers in all circumstances under the Commission's Service Quality and Reliability Standards for Electric Distribution Systems (Mich Admin Code, R 460.701 – 751) and customers' entitlement to an outage credit on their power bill in circumstances where the company fails to do so. However, it is reasonable that the company have the ability to recover outage credits when the outage was caused by customer negligence or the transmission system operator, among other circumstances as

developed in collaboration with the Staff. *See*, PFD, p. 603. [February 2, 2023 Order in Case No. U-20836, pp 366-67.]

The Company met with Staff to discuss outage cause codes credits, and the Company's ability to recover credits paid for outages that exceed the duration and frequency limits outlined in R460.744 and R460.745, respectively. The Company's position is that recoverability of credits paid for outages differs based on which of these two broad outage categories triggers the payment. Credits paid for outages that exceed the duration limit should include the following outage categories: (1) transmission operator or other utility; (2) public interference, and (3) animal interference. Credits paid for exceeding the outage frequency limits should include the following additional causes: (1) ice; (2) lightning; (3) wind; and (4) other weather. The Company's rationale for including weather-related events for exceeding outage frequency limits (but not for exceeding the duration limit) is that the Company controls the restoration time when there is a weather event, but not the frequency with which weather events occur (Foley, 2T 97-98).

The Company's proposed recovery treatment is consistent with its position in Case No. U-20836. The Company proposes that the costs of bill credits for outages beyond its control be deferred for future recovery starting after the final order in this case, and to use account 182.3, Other Regulatory Assets, for that purpose. The deferred amounts would be reviewed for reasonableness and prudency in a subsequent general rate case. Only after the deferred amounts are approved would the Company begin amortizing and recovering them (Foley, 2T 98-99; Uzenski, 6T 1558).

The Company would like to spend more time with Staff to design a recovery mechanism for credits related to frequent outages, but has some initial thoughts and a proposal. There will likely be a mix of causes if a customer meets the criteria for a frequent-outage credit. Apart from the mathematics of determining a percentage of the credit that is recoverable (i.e., beyond the

Company's control as outlined above), it would be expensive and complicated to implement an algorithm into the billing system to calculate a unique percentage to apply to each $38 credit that is being deferred for recovery. [127] The Company therefore proposes that a common percentage be applied to all frequent-outage credits. This simple and consistent factor would be based on analysis of data from the previous year, and be less costly and complicated to implement than a unique factor based on analyzing each payment. Implementation cost is an appropriate consideration in determining whether a payment methodology is reasonable.[128] The Company would like to work with Staff to develop a reasonable methodology that can be implemented without billing system complexities and corresponding costs (Foley, 2T 99).

Staff responded that "[w]hile Staff agrees with deferring the costs related to credits eligible for recovery, Staff's position is that recovery should be far more limited than what DTE Electric has proposed" (Evans, 6T 5230). Staff then proposed a methodology for calculating the specific amount of frequency-related outage credits that would be recoverable in a specific year, and stated that Staff is "open to collaborating with the Company and other intervenors after the conclusion of this rate case on finalizing the methodology for the recovery of repetitive outage credits, if necessary" (Evans, 6T 5230-31). Witnesses for MNSC (Jester, 6T 3793) and GLREA (Richter, 6T 4862) similarly opposed the recoverability of outage credits related to weather-driven events, but supported limited recoverability related to other events. The three witnesses differed somewhat in

[127] The Commission recently increased the bill credit to $40.00 as of October 1, 2024 (September 5, 2024 Order in Case No. U-20629).

[128] See generally, *Attorney General v Public Service Comm*, 235 Mich App 308, 316; 597 NW2d 264 (1999), and *Attorney General v Public Service Comm*, 215 Mich App 356, 369-370; 546 NW2d 266 (1996) ("the statute does not require adoption of the most precise possible [GCR refund] procedure. Rather, a more precise [refund] procedure may have other consequences, such as increased cost, which must be evaluated by the PSC in assessing the overall reasonableness of the procedure. The PSC may properly conclude that the refund procedure that is most precise is not to be adopted because of attendant costs.").

which outage codes they addressed and their final recommendations. The Company maintains its original position, but believes Staff's recommendation is reasonable (Foley, 2T 148).

In contrast, DAAO (Koeppel, 6T 4397; Watts, 6T 4674) and Ann Arbor (Stults, 6T 4257) recommended that the Commission fully reject the Company's proposal, and not allow for any recovery of outage credits.[129] These recommendations should be rejected because they are contrary to the Commission's determination that "it is reasonable that the company have the ability to recover outage credits when the outage was caused by customer negligence or the transmission system operator, among other circumstances as developed in collaboration with the Staff" (February 2, 2023 Order in Case No. U-20836, p 367). Since the Commission has already decided that some recoverability is appropriate, the focus should now just be on which credits are appropriate for recovery, as discussed above.

DAAO recommended that the Commission "reconsider the establishment of hourly, progressive, automatic credits as DAAO has previously argued for before the Commission" (Koeppel, 6T 4397. See also, Watts, 6T 4672-73). DAAO acknowledges that the Commission previously considered this matter. DAAO's real disagreement is with Case No. U-20629, where hourly credits were specifically contemplated during rulemaking and rejected in the Commission's September 28, 2023 Order. This is not a proper forum to dispute that Order. Moreover, Service Quality and Reliability Standards (SQRS) for electric distribution systems, and any credits to be paid to customers as a result of not meeting those standards, are established through rulemaking and not through general rate cases. DAAO's suggestion that the Commission should depart from

[129] Ann Arbor witness Stults further suggested that in the "extremely limited" circumstances where some outage credit recovery might be possible, the Company should consider outages due to customer negligence as a cost of doing business (Stults, 6T 4258-59).

its rules by ordering additional outage credits against the Company threatens an illegal result. [130] Therefore, DAAO's recommendation should be rejected (Foley, 2T 151).

F. Accounting Issues

In summary and as discussed elsewhere, the Company requests continuing deferral treatment for: (1) pension expense; (2) Other Post Employment Benefit (OPEB) expense; (3) Low-Income Assistance (LIA) /Residential Income Assistance (RIA) credits; (4) time of day (TOD) implementation costs; (5) Program Evaluation Review Committee (PERC) projects; and (6) certain Charging Forward costs. The Company also requests approval to use accounts 182.3 and 254 to record any under/over recovery from the proposed storm restoration cost sharing mechanism (SRCSM). (Uzenski, 6T 1558).

1. Tree Trimming Capitalization

AG-MN witness Alvarez asserted that "the only permitted capitalization of vegetation management spending is in the initial construction of a brand-new overhead distribution line. Any other capitalization of tree trimming expense is an unequivocal violation of the Michigan USCA" (Alvarez, 6T 3951), and recommended that the Commission require that the Company do things including "in its next case to explain the legitimacy of its decision to capitalize tree trimming expenses for distribution capital programs" (Alvarez, 6T 3952).

[130] See for example, *In re Complaint of Consumers Energy Co*, 255 Mich App 496, 501; 660 NW2d 785 (2002) (reversing the MPSC because it misinterpreted and misapplied its own rule in order to reach its desired result); *DeBeaussaert v Shelby Twp*, 122 Mich App 128, 130; 333 NW2d 22 (1982) ("Once an agency has issued rules and regulations to govern its activity, it may not violate them"); *Bohannen v Sheridan-Cadillac Hotel, Inc*, 3 Mich App 81, 82; 141 NW2d 722 (1966) ("When an administrative agency promulgates a rule for the benefit of litigants and then deprives a litigant of this right, it is a violation of both the 1908 and 1963 Michigan Constitutions").

The Company disagrees with witness Alvarez's assertion, which is a similar position to one taken by MNSC in Case No. U-21297. The ALJ disagreed, noting that "it appears the company's accounting practice has been ongoing for a while" and that a decision on the matter would be better made after the audit of the Company's accounting practices is complete (U-21297 PFD, 701). The Commission agreed with the ALJ (December 1, 2023 Order in Case No. U-21297, p 281).

Company accounting expert Uzenski further explained that Mr. Alvarez's interpretation of the Uniform System of Accounts (USoA) is flawed because he ignored the USoA's definition of Maintenance (included within Operating Expense Instructions). Maintenance expense, by definition, is related to sustaining existing assets, and includes "Replacing or adding minor items of plant which do *not* constitute a retirement unit." The tree trimming activities capitalized by the Company relate to the installation of new assets (which *do* constitute retirement units), not to maintaining existing assets (Uzenski, 6T 1576).

Mr. Alvarez apparently noted that the USoA description of account 365 (Overhead Conductors and Devices) allows for the capitalization of the initial cost of tree trimming, and then assumed that capitalization of tree trimming only applies to the first installation of electric lines, but not to the poles to which those lines are attached, or any other adjacent assets (Alvarez, 6T 3949). This reasoning is faulty and based on the unreasonable premise that every possible type of cost is listed in the description of each account. Instead, USoA General Instruction No. 6, Item Lists, states: "Lists of items appearing in the texts of the accounts or elsewhere herein are for the purpose of more clearly indicating the application of the prescribed accounting. The lists are intended to be representative, but not exhaustive" (Uzenski, 6T 1577).

Mr. Alvarez also indicated that he relied on Plant Instruction No. 9 ("Also include those items incurred with the first clearing and grading of land and rights-of-way"). He quoted this sentence, and asserted that it defines "initial cost" as used within the description of Account 35

(Alvarez, 6T 3949); however, the term "initial cost" is not mentioned in the USoA's discussion of equipment (Uzenski, 6T 1577).

Mr. Alvarez also neglected that the USoA states that the cost of equipment shall include "expenses incurred by the utility in unloading and placing the equipment in readiness to operate." Tree trimming to install capital assets is exactly that – an expense incurred to place equipment in readiness to operate. Therefore, Mr. Alvarez's accounting interpretation is not supported by a full and accurate reading of the USoA, and should be rejected (Uzenski, 6T 1577).

AG-MN witness Alvarez also inaccurately suggested that the Commission decided this issue in Case No. U-17767 (Alvarez, 6T 3950). Instead, there the Company requested capital treatment for its Enhanced Vegetation Management Program (EVMP, now re-named the Enhanced Tree Trimming Program or ETTP), which essentially removes vegetation in a clearance corridor rather than the historic clearance circle around DTE Electric's lines and equipment. The Commission approved the ETTP, but treated the costs as O&M, reasoning that it was "not presently convinced that this program is fundamentally different from enhanced clearing, the costs of which have never been capitalized" (December 11, 2015 Order in Case No. U-17767, p 27). The Commission addressed only the accounting for the EVMP (maintenance clearing of a corridor instead of a circle) in that case. The Commission did not opine on the capitalization of tree trimming as it relates to the installation or replacement of capital assets. Therefore, Mr. Alvarez's reliance on that case is misplaced (Uzenski, 6T 1579).

Therefore, the AG-MN's accounting position on tree trimming capitalization should be rejected, and there is no basis for their proposed requirements for the Company.[131]

[131] AG-MN presented only an accounting-classification issue, and did not dispute the reasonableness and prudency of the tree trimming. If the Commission were to order that tree trimming costs associated with capital work must be expensed as incurred, then the Commission should provide a corresponding increase to O&M (Uzenski, 6T 1579).

2. Shared Assets

The Company forecasted $63.5 million of revenue from shared assets (such as building and IT), assuming the capital projects in this case are approved (Exhibit A-13, Schedule C3, line 14). If the Commission disallows a capital project that is for a shared asset, then for consistency it must also remove the revenue related to that asset from projected net operating income (Uzenski, 6T 1560, 1563-64; Exhibit A-36, Schedule BB1).

IX. SUMMARY OF REVENUE DEFICIENCY AND REQUESTED RATE RELIEF

Based on adjustments identified by the Company after reviewing Staff's and other intervenors' positions and the full record in this case, DTE Electric supports and requests approximately $446.1 million in rate relief. See Attachments A and B**.**

X. COST ALLOCATION AND RATE DESIGN[132]

A. DTE Electric's Cost of Service Study Supports the Company's Rate Design Proposals

The Unbundled Cost of Service (UCOS) studies for DTE Electric's projected test period are consistent with past practices and Commission orders, including the cost-allocation methods approved in Case No. U-21297 (Maroun, 6T 2754, 2762-65; Exhibit A-16, Schedules F1.1 and F1.2).

[132] See generally supra, Section II. History of Proceedings – *DTE Electric* – Maroun, Willis, Burgdorf, Sparks, Bellini; *ABATE* – Andrews, Dauphinais; *Staff* – Pung, Isakson, Revere, Braunschweig; *CUB-MN* – Gard; *Energy Michigan* - Zakem; *Ann Arbor* – Naheedy; *MNSC* – Jester; *CEO* – Kenworthy; *DAAO* – Koeppel, Kinkhabwala; *MEC-NRDC* – Colton; *MEIU* – Barnes; *GLREA* – Richter; *MI-MAUI* -- Bunch

The typical process to develop a UCOS study consists of three steps: (1) functionalization (which assigns all costs to the major functions, *i.e.* power supply and distribution);[133] (2) classification (which divides these costs into customer-related costs, demand-related costs, and energy-related costs); and (3) allocation (which apportions the cost classifications to the respective classes of service based on the class's responsibility for the incurrence of these costs). (Maroun, 6T 2755).

The UCOS study contains 16 basic externally developed allocation schedules (Maroun, 6T 2759). Company witness Willis developed 11 allocation schedules for use in cost-of-service studies (see Exhibit A-5, Schedule E3 for a description of each schedule). He explained that these allocation schedules were developed using established industry principles, and that they were consistent with methods used in previous rate cases, and accurately represented the load characteristics for customers receiving power supply and/or distribution service from DTE Electric (Willis, 6T 2578-82). Company witness Maroun used Mr. Willis' allocation schedules, plus five more that he developed, to determine rate class cost responsibility (Maroun, 6T 2759-60, 2768).

Company witness Maroun explained how he functionalized DTE Electric's costs (6T 2756-58; Exhibit A-16, Schedule F1.3), and how the UCOS allocates costs to DTE Electric's various customer classes (6T 2758-59). He further testified that DTE Electric will experience a jurisdictional revenue deficiency of approximately $456.4 million in the 2025 projected test year, consisting of a $148.7 million base production revenue deficiency, and a $307.7 million distribution revenue deficiency. Exhibit A-16, Schedule F1.1 shows the production-related revenue (sufficiency)/deficiency associated with each consolidated cost-of-service rate class. Exhibit A-16,

[133] Power supply (generation and transmission) includes costs associated with the Company's generating plants, fuel, purchased power, and the transmission services that it receives from MISO and ITC. Distribution includes the costs associated with the Company's distribution system, which generally operates at voltages of 40kV and below, and includes customer service expenses (Maroun, 6T 2756).

Schedule F1.2 shows the distribution-related revenue (sufficiency)/deficiency by cost-of-service voltage class (Maroun, 6T 2762-64).

The Company proposes to continue using the same allocation methods for production and transmission that were approved in the December 1, 2023 Order in Case No. U-21297 (Maroun, 6T 2765-66). DTE Electric uses three allocation bases for distribution: (1) demand, (2) customer, and (3) those based on special studies.[134] The Company proposes to allocate distribution by voltage level class (residential secondary, commercial secondary, primary, sub-transmission, transmission, and lighting (E-1 Street Lighting, D-9 Outdoor Protective Lighting (OPL), and E-2 Traffic Signals[135]), consistent with the allocation methods that the Commission approved in Case No. U-21297 (Maroun, 6T 2767). Exhibit A-16, Schedule F1.4 calculates monthly customer charges by voltage level, using the Staff method approved in the December 1, 2023 Order in Case No. U-21297 (Maroun, 6T 2770).

The Commission previously adopted the following changes to allocation methodologies: (1) EV Program Costs; (2) Rider 10 Tax Gross-Up Adjustment; and (3) Demand-Related Distribution Plant-Related Costs (December 1, 2023 Order in Case No. U-21297, pp 295, 297, 300). The Company used those allocation methodologies in this case (Maroun, 6T 2766).

Exhibit A-16, Schedule F2 shows summarized present and proposed rate designs and corresponding revenues by rate schedule. Schedule F3 Revised shows rate schedule level detail of

[134] Cost causation for distribution is determined by the parameters used to design and build the system. Distribution planning takes future load growth and reliability into account, so the system will generally have the capacity to support additional loads. Therefore, once installed, distribution system costs are generally not affected by increases or decreases in either demand or energy until the circuit limit (demand threshold) is approached. When viewed prospectively, however, distribution system design cost is caused by the number of customers served and the maximum demand placed on the system at a given voltage level (Maroun, 6T 2768).

[135] Lighting is maintained as a separate class because it has a significant amount of dedicated infrastructure costs that should be assigned directly (Maroun, 6T 2767).

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present and proposed revenues and resultant pricing. Exhibit A-16, Schedule F4 calculates typical bills for each rate schedule based on the Company's present and proposed rates. Exhibit A-16, Schedule F8 contains the proposed rule and tariff sheet changes (Willis, 6T 2574 2585-86 2613). Company witness Willis summarized the Company's residential rate design (6T 2587-94), commercial secondary rate design (6T 2595-2605) and primary rate design (6T 2605-13). Further detail is discussed below in the context of the specific proposals.

MNSC witness Jester recommended that the Commission "require that DTE Electric file in its next rate case an analysis of the seasonality for cost causation of distribution costs and distribution rate designs consistent with that seasonality" (Jester, 6T 3800), indicating that he relied on MNSC witness Woolley's proposition that transformer aging largely occurs in the summer (Jester, 6T 3795).

The Company disagrees. In addition to technical points regarding the underlying propositions about transformer aging (Deol, 5T 1268-69), the recommendation is insufficiently supported and ambiguous. It is unclear what MNSC might have in mind, and the Company should not be required to invest the significant time and resources needed to perform a study merely because some intervenor(s) might be curious or seek to fill some undefined future data interest. Also from a COSS perspective, MNSC's proposal that the Company somehow integrate seasonal variations into the distribution COSS model taking into account the proposition that transformer aging "occurs almost exclusively during Summer months June through August" (Jester, 6T 3795) appears to support allocating distribution costs based on summer peak demand, which aligns with the use of the 4CP method for allocating the demand portion of production plant costs, which

remains appropriate and is now undisputed.[136] The Company disagrees with MNSC's suggested approach because it would deviate from the Commission-approved non-coincident class (NCP) peak allocators for apportioning distribution plant costs by voltage level, particularly based on summer peak demands. Moreover, the existing COSS model is already extensive. Adding seasonality would expand this complexity without any evidence that this would yield a more accurate result. Therefore, MNSC's recommendation should be rejected (Maroun, 6T 2781, 2793-95).

Staff recommends that allocator 255 be used to allocate purchased power capacity costs in alignment with the Commission's long-standing practice of recognizing the dual nature of production assets. Allocator 255 is a 4 CP 75/0/25 allocator and would align the Company with Michigan's other large electric provider, Consumers Energy Company (Pung, 6T 4951). The Company instead proposes to continue allocating purchased power capacity costs using 4CP 100-0-0 demand less R10 (allocator 251)[137] and purchased power energy using 0-0-100 energy less R10 (allocator 111). If the Commission agrees with Staff and changes the allocation to align the allocation of purchased power capacity with the current allocator for production plant using allocator 255 (4 CP 75-0-25), then it would be prudent to ensure consistency in the allocation of

[136] The Commission adopted the 4CP 75-0-25 method for allocating certain production costs in Case No. U-17689 (in accordance with 2014 PA 169) and has continuously applied it in subsequent DTE Electric rate cases. MNSC witness Jester and CUB-MN witness Denzler initially made a number of proposals to change the 4CP allocator, with cost allocation and rate design consequences, which are now moot due to their submission of revised testimony deleting these discussions. Accordingly, the Company does not discuss the matters further here, other than to note that the proposals lacked merit as discussed in the rebuttal testimony of Company witnesses Willis (6T 2626-27) and Maroun (6T 2782-91). Staff similarly observed the significant customer impacts of witness Jester's rate design proposals (Isakson, 6T 4909-12).

[137] ABATE agreed (Andrews, 6T 3513).

purchased power energy and fuel costs. Currently, fuel costs are allocated using allocator 192 (12 CP 10-0-90). (Maroun, 6T 2781-82, 2796-97).[138]

B. Rider 10

ABATE witness Dauphinais proposed that the Commission "require DTE to modify its R10 tariff to allow all R10 customers on an annual basis to choose between the applicable day-ahead LMP or the applicable real-time LMP" (Dauphinais, 6T 3384). The Company disagrees. If customers switch regularly and are allowed to choose between the two different LMPs, this would create additional burdens and cost to the Company for tracking and billing (Burgdorf, 6T 2351-52).

C. State Reliability Mechanism (SRM) Capacity Charge

Company witness Maroun calculated and explained the Company's capacity charge revenue requirement, which is reflected on Exhibit A-16, Schedule F1.5 Revised. He used the same methodology that the Commission approved in its December 1, 2023 Order in Case No. U-21297. The capacity charge revenue requirement includes all production-related costs per Exhibit A-16, Schedule F1.1, except for adjustments for fuel, variable O&M, MERC, and certain purchase power costs (Maroun, 6T 2770-74).

Company witness Burgdorf further explained the underlying calculations (6T 2338-45) and summarized that the total projected 2025 wholesale energy revenue of $2.184 billion, net of $1.201 billion in fuel-related costs, equates to $0.983 billion wholesale energy sales revenue net of fuel costs as shown on Exhibit A-26, Schedule P3, line 22 (Burgdorf, 6T 2345).

[138] There are also two minor errors in Staff's as-filed Excel COSS model that should be corrected/updated for the COSS model corresponding to the final order: (1) D13 Incremental Distribution Revenue, and (2) Low Income and Senior Discounts (Maroun, 6T 2784, 2797-98).

Company witness Maroun further explained that he used the same methodology utilized in Case No. U-21297 to calculate the MERC revenue requirement (Maroun, 6T 2771; Exhibit A-16, Schedule F1.5, line 3). Mr. Maroun also reduced the capacity charge revenue requirement for non-capacity related purchased power (Exhibit A-16, Schedule F1.5 Revised, lines 4 and 5). He did so because these costs are for energy charges purchased from MISO for Rider 3 and Rider 10 (line 4) and other energy related purchased power (line 5). (Maroun, 6T 2771-72). Mr. Maroun adjusted variable O&M (Exhibit A-16, Schedule F1.5 Revised, line 6) by including Account 501 (Fuel Handling), and the non-labor portions of Accounts 502 (Steam Expenses), 505 (Electric Operation Expenses), 519 (Coolants and Water), 520 (Steam Expenses), 538 (Electric Maintenance Expenses) and 548 (Peaker Expenses). This is consistent with Chapter 4 of the NARUC Manual, which reflects that labor expenses are considered demand-related, while material expenses are considered energy-related. Thus, only material-related costs are variable (Maroun, 6T 2773).

The resulting total capacity charge revenue requirement is $973.7 million (Exhibit A-16, Schedule F1.5 Revised, line 11). Mr. Maroun allocated it to the various rate classes using Allocator 251, 4CP (Schedule 200B) excluding R10, which is the methodology approved in Case No. U-21297 (Maroun, 6T2774).

Energy Michigan witness Zakem asserted that removing $260.787 million of fuel cost associated with power purchase agreements (PPAs) and Company-owned renewables would result in an SRM capacity charge of $159.21/MW-day (Zakem, 6T 4165).

The Company disagrees because witness Zakem only removed the $260.787 million value from fuel costs used to calculate the "energy sales revenue net of fuel costs" in Exhibit A-26, and used in Exhibit A-16, Schedule F1.5 Revised. If the $260.787 million is not considered fuel, then this amount would be considered a capacity-related cost, resulting in the amount also needing to be removed from Exhibit A-16, Schedule F1.5, line 5. Thus, witness Zakem's recommendation would

have no impact on the Company's as-filed $217.30/MW-day SRM capacity charge (Burgdorf, 6T 2347-49; Maroun, 6T 2781, 2795; Exhibit A-38, Schedule CC2).

Energy Michigan witness Zakem further suggested that the Commission "could require that the SRM Capacity Charge also be determined by season" (Zakem, 6T 4177). The Company disagrees because this would create significant additional burdens, which would require corresponding time and effort to address. The proposal is also unnecessary because the annual rate recovers the same costs as the rate would recover if it were computed seasonally (Burgdorf, 6T 2349-50). The Commission also previously declined to adopt Energy Michigan's similar proposal (December 1, 2023 Order in Case No. U-21297, p 307).

Energy Michigan witness Zakem further suggested that a "workable and fair solution would be to set the SRM Capacity Charge at the MISO seasonal Auction Clearing Price and apply that charge to the MW value of the deficiency, for the days of the season that an LSE is deficient" (Zakem, 6T 4182). The Company disagrees because the proposal is short-sighted and contrary to MCL 460.6w. MISO's Planning Resource Auctions (PRAs) do not ensure resource adequacy, so using MISO's auction clearing prices to set the SRM capacity charge would effectively negate long-term resource planning (Burgdorf, 6T 2350-51). Staff similarly disagreed with witness Zakem (Revere, 6T 4969-70).

Energy Michigan witness Zakem's discussion also suggests departing from MCL 460.6w, as if the statute should be construed according to Energy Michigan's preferences. It is axiomatic, however, that the Commission cannot re-write the Legislature's language to include new or different provisions.[139] Our Supreme Court has also recognized that, notwithstanding MISO, "the

[139] *Hanson v Mecosta Co Rd Comm'rs*, 465 Mich 492, 501-503; 638 NW2d 396 (2002). See also *In re Complaint of Rovas Against SBC Michigan*, 482 Mich 90, 98; 754 NW2d 259 (2008) ("agencies cannot exercise legislative power by creating law or changing the laws enacted by the Legislature").

Michigan Legislature passed Public Act 341 to promote and ensure the long-term reliability of Michigan's electric grid" and that the Commission "is charged with ensuring the reliability of Michigan's grid for retail consumers throughout the state." [140]

Staff proposed an "Alternative SRM Calculation" (Revere, 6T 4961-65). The Company disagrees with Staff's suggestion that the proper cost of capacity is CONE, or the cost to build a new combustion turbine. The cost of the Company's capacity fleet is based on many diverse resources required to maintain a reliable grid. Staff also suggests that its proposed alternative avoids pitfalls, but did not provide a sample calculation to prove how it may fluctuate during high and low market prices. Therefore, due to the lack of detail and possibilities for misinterpretation, Staff's Proposed Alternative SRM Calculation should not be adopted (Burgdorf, 6T 2351).

D. Residential Rate Design Proposals

The Company's residential rate schedules are summarized at Willis, 6T 2596-97. Exhibit A-16, Schedule F3 Revised shows the present and proposed rate designs and corresponding revenue by rate schedule (Willis, 6T 2585). Exhibit A-16, Schedule F4 shows a comparison of typical monthly bills by rate schedule based on present and proposed rates (Willis, 6T 2590).

The proposed residential power supply capacity and non-capacity rates were designed to recover the revenues pursuant to Company witness Maroun's Exhibit A-16, Schedule F1.5 Revised, which shows how much of the power supply revenue requirement for each rate class is capacity and non-capacity related. Within the power supply cost of service, Witness Maroun identified three separate residential cost classes: "D1.11/Other", "D1.2", and "D2". All current residential rate schedules except D1.2 and D2 are included in D1.11/Other. For the D1.11/Other rate schedules, the power supply deficiency was allocated based on each rate schedule's percentage contribution to the

[140] *In re Reliability Plans of Electric Utilities for 2017-2021*, 505 Mich 97, 114, 128; 949 NW2d 73 (2020).

present D1.11/Other power supply revenue. For those rate schedules with their own cost of service class (D1.2and D2), the deficiency was directly allocated to the corresponding class. This is the same method used to develop the approved residential power supply rates in the Company's last general rate case, Case No. U-21297 (Willis, 6T 2588-89).

Rate Schedule D1.7 is a separately-metered rate available for supplemental geothermal electric service with rates dependent on season and time of day. The Company proposes to design Rate Schedule D1.7 non-capacity charges on a time-of-use basis such that the D1.7 non-capacity rate structure would be the same as the D1.7 capacity rate structure—pricing differentials are consistent with the ordered D1.7 power supply design in Case No. U-20836. This approach is similar to currently-approved Rate Schedules D1.11, D1.2, and D1.8. This change would further align rate design methodologies across the residential rate schedules (Willis, 6T 2587, 2589).

In the Company's general rate case filed in 2014, Case No. U-17767, Staff recommended, and the Commission approved, variable distribution rates designed such that all customers in the Residential class would have the same rate, with the caveat that a cap was applied to limit the increase of any specific variable distribution rate. This method was again proposed and approved in the Company's subsequent general rate cases, Case Nos. U-18014, U-18255, U-20162, U-20561, U-20836 and U-21297. The Residential Secondary rate schedules now all have the same distribution rate, so no cap is applied in this case. The sole exception is Rate Schedule D1.13, which has variable distribution rates designed consistent with the Order in Case No. U-21297 (Willis, 6T 2589-90).

CUB-MN witness Gard (6T 3825) and MNSC witness Jester (6T 3796) proposed that the Company study separate single-family and multi-family cost-of-service classes and rate design, and separate electric space heating cost-of-service and rate design. The Company disagrees because the information that would be needed to conduct such studies does not exist. As a standard business

practice, the Company does not know which customers are single-family or multi-family. Moreover, unless customers are using a specific rate product or program that requires them to specify appliances they are using (e.g., electric space heating on Rate Schedule D2), the Company has no way of knowing which appliances any customer has (Willis, 6T 2621-22). Thus, the Company has no ability to conduct the study proposed by witness Jester and it should be rejected.

Even if the Company had the necessary data, there is no specific significance to single-family vs. multi-family or electric space heating as it concerns which usage drivers ought to be considered for their own cost-of-service class (Willis, 6T 2622-23). CUB-MN witness Gard's analytical approach also raises concerns because: (1) the study data was used for purposes other than intended (the breakdown of load curves by housing type is entirely based on the NREL ResStock Tool, which is focused on building energy-efficient investments, with no suggestion that the data is precise, specific, or accurate enough to serve as the basis for assertions regarding cost-of-service and actual customer load shapes); and (2) the analysis ignores other factors that could impact load shapes (Willis, 6T 2623-24).

Witnesses Gard and Jester's proposal for new cost-of-service classes and rate schedules for electric heating customers also neglect that the Company already serves a portion of customers on rate D2, which is a voluntary base service for customers with electric space heating (and who self-identified so the Company could conduct a cost-of-service study and offer the rate), which the Commission closed to new enrollments in 2015. Thus, to the extent that witnesses Gard and Jester seek an optional electric space heating rate, the Commission previously closed that product, and to the extent that they suggest a mandatory rate, the Company lacks the necessary data and the approach would be inappropriate even if the data existed. Therefore, witnesses Gard and Jester's proposals should be rejected (Willis, 6T 2625-26).

1. Rate Schedule D1.6 Transition and Closure

In Case No. U-21297, the Company proposed 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's standard residential service rate, with rates that vary depending on season and time of day). The Company also proposed to expand the availability of the LIA credit to all residential base rates. The Commission declined to approve the Company's proposal, stating:

> The Commission remains supportive of TOU rates; however, the Commission agrees with the DAAOs and finds it appropriate for DTE Electric to conduct an impact study comporting to the DAAOs' recommended report outline before retiring Rate Schedule D1.6 and transitioning customers to Rate Schedule D1.11. The Commission finds that Rate Schedule D1.6 should continue at this time, with the issue to be revisited in the company's next rate case and with the company's study to help inform the appropriate path forward. [December 1, 2023 Order in Case No. U-21297, pp 312-13.]

The Company again proposes to (1) open LIA credit availability to all residential base rate schedules, (2) transition D1.6 customers to D1.11, and (3) retire D1.6. Rate Schedule D1.6 would be retired as the final piece of the Company's transition to TOU rates for residential customers (except for the small number of customers remaining on Rate Schedule D1 Non-Transmitting Meter Rate, and this alternative would remain available for any D1.6 customer with a non-transmitting meter). Upon approval the Company would complete rate transition and retirement by the end of the projected test year. (Willis, 6T 2590-91, 2594).

The Company conducted an impact study, which showed that the average impact was a 0.17% bill decrease. There is a narrow distribution of bill changes when comparing D1.6 and D1.11. The average change is a very slightly lower bill on D1.11. All else being equal, 58% of customers in the analysis would see a lower bill on D1.11 (Willis, 6T 2592-93, 2629). This near-zero positive average impact confirms that there is no structurally-adverse impact of transitioning D1.6

customers to D1.11. Company witness Willis further explained that Rate Schedule D1.6 maintains the "inverted block rate" structure. With the wide implementation of advanced meters, TOU is now a more precise way to design rates.

DAAO acknowledged the primary conclusion of the Company's study that most customers would benefit from being on Rate D1.11 (Koeppel, 6T 4406), but suggested that further analysis should be done, and recommended that "the Commission (1) reject DTE Electric's request to retire the D1.6 flat rate for low-income customers and transition all customers to the D1.11 TOU rate at this time, and (2) require DTE Electric to conduct a more comprehensive and collaborative study of the potential impacts and opportunities of TOU rates for low-income customers" (Koeppel, 6T 4409).

The Company disagrees because there is no obvious end point to the analysis proposed by witness Koeppel and the Commission approved the transition of almost two million customers from D1 to D1.11 without the type of data sought by witness Koeppel. CEO witness Kenworthy also agreed that low-income customers are generally better off under a TOU rate (Kenworthy, 6T 3229). There is no reasonable basis for further delay or analysis, so the Commission should now adopt the Company's three proposals (Willis, 6T 2627-31). Staff agreed that the Company's proposals should be adopted (Isakson, 6T 4907).

2. Energy Assistance Programs

Company witness Willis proposed changes to residential tariff language reflecting the expansion of the LIA credit to all residential base rates, and the Company's proposal to increase the LIA credit from $40 to $50 (Willis, 6T 2614; Exhibit A-16, Schedule F8).

Staff disagreed with the Company's proposal to increase the LIA credit from $40 to $50, recognizing that "Michigan's most vulnerable customers would benefit from additional assistance,"

but stating that it was not persuaded that the Company "provides the comprehensive analysis and diverse, collaborative input the Commission is looking for to inform utility energy assistance changes," and that it would be preferable to "leave this issue to the EAAC [Energy Affordability and Accessibility Collaborative] until it completes its relevant Commission directives (Braunschweig, 6T 3525-26, 3528).

The Company maintains its position because the proposed LIA credit increase is just to keep the credit aligned with its original function. The December 11, 2015 Order in Case No. U-17767 approved the creation of Rate Schedule D1.6, which included the $40 LIA credit. The Company's proposal to increase the credit to $50 is designed to align the financial support provided to low-income customers receiving LIA with the originally-approved credit offset as a percentage of their bills. The Company does not propose to change the LIA credit's structure, nor change potential EAAC outcomes. Meanwhile, there are low-income customers struggling with bill affordability who would greatly benefit from the proposed increase (Sparks 6T 2373, 2385-86; Willis, 6T 2590, n 2).[141]

The Residential Income Assistance (RIA) credit provides low-income customers with an $8.50 per month credit on their bills. The Company forecast the RIA credit enrollment average of 83,000 customers (Sparks, 6T 2369-70). Staff proposed 56,134 (with a corresponding revenue adjustment of $2,740,321) based on using a three-year historical average monthly credit disbursement number (Braunschweig, 6T 3531).

[141] DAAO suggested that bill affordability is causing non-pay disconnects to increase, based on the "Customer Disconnects by Utility" chart on the MPSC Utility Customer Data Tool website (Kinkhabwala, 6T 4545-4546). The suggestion is inaccurate, and apparently based on a misunderstanding of the data, which is cumulative and not the number of actual disconnects for any given month (Sparks, 6T 2384-85).

Mr. Sparks further explained why certain LIA recommendations by MEC/NRDC witness Colton should be rejected as contrary to established practice and controlling law, and others would be more appropriately addressed by EAAC workgroups (Sparks, 6T 2390-91).

The Company maintains its position. Staff was apparently concerned about the Company including 2023 RIA counts, because that data was not included in historical Part III reporting (Braunschweig, 6T 3531). Staff's indicated concern about accuracy is unwarranted, as demonstrated by tables showing minimal differences between the 2020-2023 data included in Mr. Sparks' direct testimony, and the 2020-2022 data included in Part III Attachment 5(9). (Sparks, 6T 2387). Company witness Sparks also explained why Staff's further reasoning (Braunschweig, 6T 3532-35) is incorrect (Sparks, 6T 2388-90).

Mr. Sparks also responded to a variety of other proposals as inaccurate, unsupported, and/or more appropriately considered elsewhere (Sparks, 6T 2391-98).

Staff proposed a Residential Senior Credit (RSC) customer count of 94,525 based on a three-year (2020-2022) average (Braunschweig, 6T 3535). The Company originally proposed 104,224, which reflects a trendline from Staff's historical years, and included 2023 data to date when that number was finalized. Full 2023 actual credits averaged 109,754 monthly. To-date 2024 credits are averaging 125,141 monthly. The Company also made an error in its initially-filed forecast, which undercounted the forecast by 19,849 (Exhibit S-17, pp 5-6). Therefore, the Company's initially-proposed 104,224 is reasonable, and likely under-forecast. Moreover, the senior credit is not tracked or reconciled, so an under-forecast is not recoverable. Therefore, the Commission should update the Company's initial forecast of 104,224 to include the 19,849 credit counts that were inadvertently excluded from the Company's initial filing, for a total of 124,073 (Willis, 6T 2619).

E. Commercial Secondary Rate Design Proposals

The Company's commercial secondary rate schedules are summarized at Willis, 6T 2596-97. DTE Electric's commercial secondary rate design is consistent with the methodology that the Commission approved in past cases. The Company does, however, propose a change to previous

rate design for Rate Schedule D1.7 (Secondary), with proposed non-capacity power supply rates that vary across summer and winter, and by time-of-use period (instead of the previous rate design's flat non-capacity energy charge). This change ensures consistency with the existing D1.7 rate design, and mimics the proposed design structure for residential D1.7 (Willis, 6T 2597-99).

Rate Schedule D3.5 is the Company's Charging Hub Rate. It has zero forecast determinants in this case, so the energy charges increase by the same percentage as Rate Schedule D3 power supply charges (Willis, 6T 2599).

1. Rate Schedule D3.11, Commercial Secondary Time of Use

The Commission previously ordered: "For its next general rate case, DTE Electric shall develop and present optional time-of-use rates for its commercial secondary and primary customers" (December 1, 2023 Order in Case No. U-21297, p 372). Accordingly the Company proposes Rate Schedule D3.11 as an optional time-of-use rate for commercial customers (Willis, 6T 2599-2603; Exhibit A-16, Schedules F3 Revised and F8). As discussed in section X. F. 1 below, the Company also proposes Rate Schedule D14 as an optional time-of-use rate for primary customers (MEIU's and GLREA's proposals regarding D3.11 and D14 are addressed collectively there).

The commercial rate schedule is designed to be revenue neutral to Rate Schedule D3 (the Company's general service rate for non-residential customers) until there is sufficient historical usage to determine the utility of, and potentially implement, a separate revenue line in the D3/Other cost of service class, or a separate cost of service class. Enrollment is capped at 1,000 customers to account for potential unanticipated usage patterns on the rate, which is consistent with the Commission's approval of Rate Schedule D1.13 (a residential, voluntary time-of-use rate) in Case No. U-21297 (Willis, 6T 2600-2601).

The Company proposes pricing that varies by season (summer pricing in June – September; Non-summer pricing in October- May) and time of day (On-peak from 1:00 pm – 5:00 pm, Monday – Friday; Off-peak in all other hours), which are days and seasons consistent with the Company's default residential rate schedule The 1:00 – 5:00pm on-peak period aligns with both the system coincident peaks during the summer months as well as the secondary class peaks in the summer months. Company witness Willis further discussed details underlying the initial rate design, and explained that upon approval from the Commission, the rate would need to be developed, tested, and implemented on the Company's billing system. The Company intends to have the rate available for customers no later than the end of the projected test year (Willis, 6T 2601-2603).

2. EV Fast Charger Rate

The Commission previously found that "DTE Electric should be required to conduct a separate COSS to allocate appropriate costs to fast charging and design and propose rates for this specific class of customer in its next rate case" (December 1, 2023 Order in Case No. U-21297, p 342. See also, p 373). Accordingly, the Company submitted an Alternate COSS with EV DC Fast Charging (Alternate COSS with EV DCFC) as a separate class (Maroun, 6T 2776-77; Exhibit A-16, Schedule F1.6 (Production by Customer Class, TME December 31, 2025); Schedule F1.7 (Distribution by Voltage Class, TME December 31, 2025); and Schedule F1.8 (Capacity Charge Revenue Requirement by Customer Class).

Company witness Willis calculated the Company's proposed EV fast charger rate, which is designed as a secondary rate with time-of-use power supply pricing that varies by time period and season. Both capacity and non-capacity include on on-peak period of 1:00 – 5:00 pm, Monday – Friday, and a seasonal component with summer rates effective June – September, and non-summer rates effective in all other months. The pricing differential among the four periods is based on the

relative differences in LMP, consistent with the proposed Rate Schedule D3.11 and the currently-effective Rate Schedule D1.11. Delivery rates are designed to recover the revenue requirements allocated by Company witness Maroun, including a service charge consistent with Rate Schedule D3. The distribution rate is designed as a flat volumetric rate. All surcharges are consistent with a similarly-situated D3 customer (Willis, 6T 2600, 2603-2604; Exhibit A-16, Schedule F9 Revised).

Company witness Willis further explained that the Company developed the determinants and load shape for the rate based on usable historical data from 21 chargers (from a total of 68 known EV fast chargers of customers taking service from the Company, reduced by using information from chargers on separate meters, and excluding chargers with fewer than 300 read days). This data supports a reasonable first step of analysis for discussion purposes, but the data has two notable constraints: (1) the sample size is too small, which can cause volatility due to individual changes having outsized impacts on the overall class; and (2) the sample does not include all EV fast chargers served by the Company due to the co-location of charging load with other general service loads. Therefore, the proposal should be used as a starting point for discussion only, and not as a rate to be implemented at the conclusion of this case (Willis, 6T 2600, 2604-2605).

F. Commercial and Industrial Primary Rate Design Proposals

Company witness Willis described the Company's primary rate schedules,[142] and explained that no changes were made to existing rate design. The Company's proposed primary delivery rates

[142] Rate Schedule D11 is the Company's main primary rate schedule and is available to customers served at primary, sub-transmission, or transmission voltage. Rate Schedule D6.2 is available to educational institution customer locations (schools, colleges and universities) desiring service at primary, sub-transmission, or transmission voltage. Rate Schedule D8 is the Company's primary voltage interruptible rate, which is limited to 300 megawatts. Rate Schedule D10 is the Company's all-electric school building rate (including electric space and water heating). Rate Schedule D12 is the Company's Experimental Large Customer Low Peak Demand Supply rate. Rate Schedule D13 is the Company's XL Large Industrial Rate. Riders 1.1 and 1.2 are specific interruptible rates for customers operating electric furnaces for metal melting (Rider 1.1), or using electric heat as an integral part of manufacturing (Rider 1.2). The Company's

are cost-based by voltage level, utilizing the distribution base revenue deficiency/sufficiency levels by voltage class as reflected on Exhibit A-16, Schedule F1.2. All primary rates will have the same $/kW charges shown in column (h) of Exhibit A-16 Schedule F5, except Rate D10 and Riders R1.1 and R1.2, which have energy-based delivery charges. Mr. Willis calculated energy charges for these rates that are equivalent to the proposed voltage level distribution charges. Rate Schedule D13 is also a primary rate schedule with energy-based delivery charges (Willis, 6T 2605-2608).

1. Rate Schedule D14, Primary Time of Use

The Commission previously ordered: "For its next general rate case, DTE Electric shall develop and present optional time-of-use rates for its commercial secondary and primary customers" (December 1, 2023 Order in Case No. U-21297, p 372). Accordingly, the Company proposes Rate Schedule D14 as an optional time-of-use rate for primary customers (Willis, 6T 2609-13; Exhibit A-16, Schedules F3 Revised and F8).

The rate schedule is designed to be revenue neutral to Rate Schedule D11 (the Company's standard primary voltage rate) until there is sufficient historical usage to determine the utility of, and potentially implement, a separate revenue line in the D11/Other cost of service class, or a separate cost of service class. The Company proposes pricing that varies by season (summer pricing in June – September; Non-summer pricing in October- May) and time of day (On-peak from 11:00am – 7:00pm, Monday – Friday, excluding holidays as defined in Section C11 of the Company's rate book, which is consistent with Rate Schedule D11; Off-peak in all other hours). (Willis, 6T 2609-11).

Rider 3 rate provides standby service for various customers with generation facilities operating in parallel with the Company's system. Finally, Rider 10 is an interruptible supply rate available to customers with larger interruptible loads (Willis, 6T 2605-2606).

Company witness Willis further explained that there are risks of customers shifting from Rate Schedule D11 to the proposed Rate Schedule D14. Rate Schedule D11 is a demand-based rate that encourages more efficient usage of the system, which in turn results in a lower average cost. The proposed Rate Schedule D14 reduces the incentive for customers to operate efficiently. Until such time as Rate Schedule D14 is supported by its own cost-of-service class, this may lead to an under-recovery of cost, which would ultimately be allocated to other customers. Therefore, the Company proposes to limit total load on this rate to 50 MW of contract capacity. The Company also proposes a minimum contract term of 36 months, which will support stability in cost of service and pricing, and limit opportunities to arbitrage between Rate Schedules D14 and D11 (Willis, 6T 2611-12).

Upon approval from the Commission, the rate would need to be developed, tested, and implemented on the Company's billing system. The Company intends to have the rate available for customers no later than the end of the projected test year (Willis, 6T 2612-13).

In connection with this proposal and the Company's proposed Rate Schedule D3.11 as an optional time-of-use rate for commercial customers (discussed in section X. E. 1 above), MEIU witness Barnes proposed that the Commission should instead establish C/I TOU rates that (1) "modif[y] the Company's proposal by creating a TOU corollary for Rate Schedule D4 in addition to those proposed for Rate Schedules D3 and D11"; (2) the C/I TOU rates should have a common on-peak pricing period of 1:00 – 5:00 PM weekdays, which would change the Company's proposed on-peak period for D14; and (3) the Company's proposed enrollment caps should be eliminated (Barnes, 6T 4160). The Company disagrees, as discussed below.

MEIU witness Barnes based his first proposal (a third TOU rate associated with D4) based on his conclusion that D4 customers would lack sufficient choice of rate schedules unless the Company also offers a TOU rate that is revenue neutral to D4, arguing that D3 and D4 should have

linked TOU rate schedules because the average power supply rate on those rates is not the same. The Company disagrees because the average effective rate on any rate schedule is driven primarily by the efficiency of the usage on the rate. All else being equal, a cost-of-service class with a higher load factor will have a lower average rate than one with a lower load factor. Rate Schedules D3 and D4 are in different cost-of-service classes, and D4 has a higher average load factor and thus lower average rates. D4 rate design, which utilizes demand charges, reinforces this self-selection for higher load factor customers. If the Company offered a TOU rate using a D4 revenue-neutral design, the "lower rate" would be a fleeting reality due to customers shifting rates, which would affect costs, which would get incorporated back into the rates. D3 is also the "mass market" analog with approximately 200,000 customers, in contrast to D4 with less than 10,000 customers (Willis, 6T 2633-34).

The Company also disagrees with MEIU witness Barnes' proposal that the Company's proposed D14 rate use the same 1:00 – 5:00 PM on-peak period as the proposed D3.11 rate. The Company designed the D14 on-peak period to maintain consistency with the existing D11 on-peak period. The proposed D3.11 on-peak period is designed to (1) broadly align with summer system coincident peaks (which aligns pricing period with system highest use periods); and (2) summer class peaks (which limits the possibility that the new on-peak period could drive snapback and inadvertently set a new class peak hour on the edge of the on-peak period). (Willis, 6T 2635).

Witness Barnes' indicative D14 rates under a 1:00 – 5:00 PM scenario also appear to assume no change in load behavior, which is highly unlikely for voluntary TOU rates with new, shorter TOU pricing windows. The Company's proposed D14 included no shift because it mimics the existing TOU pricing window on D11 (Willis, 6T 2525).

Witness Barnes recommended eliminating the Company's proposed enrollment caps on Rate Schedules D3.11 and D14, essentially reasoning that enrollment caps prevent customer

enrollment on rates, and dismissing the prospects and consequences of under-recovery. The Company disagrees because the evidence does not support the proposition that caps will prevent enrollment, at least in the near-term. Moreover, short-term caps prevent adverse outcomes. The Company's best available forecast of customer usage on the proposed D3.11 and D14 includes more uncertainty than a long-existing rate because they each introduce fundamentally different pricing signals to customers. The Company's existing rates have strong historical, empirical data to support forecasts – new rates with fundamentally different pricing structures do not. One outcome of this, particularly for larger and more sophisticated primary customers, could be drastically different load profiles than what was anticipated based on historical information (and ultimately incorrect cost allocation assumptions). The Company recognizes that actual revenue is unlikely to be exactly the ordered revenue requirement, but it is inappropriate to introduce potential structural drivers of under-recovery. While D14 is allocated costs based on the load factor and efficiency of D11, it will almost certainly have a lower realized load factor due to the fact that the rate is more attractive to lower load factor customers. In the short run, their effective rates would be artificially low (Willis, 6T 2637-38).

Witness Barnes further proposed that the "C/I TOU rates should be made available for customer enrollment within three (3) months of the Commission's final order in this case," and also that the Company in that same time develop a C/I rate modeling tool that produces standardized reports for customers (Barnes, 6T 4160). The proposals are unreasonable because three months is not enough time for all of the necessary design, development, and testing activities. Actual implementation timing will depend on whatever the Commission orders, but will likely require significant modifications to the Customer Relationship and Billing (CR&B) back-end and front-end systems, customer-facing channels such as the web, system integrations, and reporting (Hatsios, 6T 2326-27).

GLREA witness Richter proposed that "it would be accurate to assign the entire cost of capacity to the peak demand time period" periods in the Company's proposed Rate Schedules D3.11 and D14 (6T 4808), and that the Company should be ordered to redesign the rates to do so (6T 4863). The Company disagrees as discussed below.

Witness Richter reasoned that economic efficiency is the only important consideration in rate design (6T 4808). The Company disagrees that its capacity only exists to serve the 4CP (or the on-peak periods more generally). The Company has load at all hours of the day and must have capacity to serve that load. The recommendation also suggests that all capacity costs be recovered in only the 4CP on-peak periods to maintain consistency with the basic approach of production plant allocation. This would create extraordinarily high summer on-peak rates (Willis, 6T 2642).

Witness Richter also mischaracterized D3.11 and D14 as "pilot" rates (e.g., 6T 4863) and further asserted that "an optional, pilot rate is exactly the right place to try a bold test of rate design that recovers capacity costs accurately" (6T 4810). In addition to the prior discussion regarding the impropriety of witness Richter's views on capacity cost recovery, proposed Rate Schedules D3.11 and D14 are not pilots, but instead are intended to be enduring, reasonable designs for C&I TOU rates. Moreover, Witness Richter's proposal to move toward making such rates mandatory as "the default, standard rate schedule" (6T 4863) is inappropriate because the rates should remain optional. It would be exceptionally premature to begin any discussion of requiring these rates when the Commission has yet to approve their basic structure and there currently are no customers enrolled on them (Willis, 6T 2643).

Therefore, the Commission should approve the Company's proposed rates as filed, and reject MEIU's and GLREA's contrary and additional proposals (Willis, 6T 2637, 2643).

G. Streetlighting Rate Design

Community Lighting provides Commission-approved tariff service to approximately 166,000 street lights on its E1 Option I Rate Schedule, 119 municipally-owned street lights on its E1 Option II Rate Schedule, approximately 82,000 municipally-owned street lights on its E1 Option III Rate Schedule, and approximately 33,000 outdoor protective lights (OPLs) on its D9 Rate Schedule. Community Lighting also provides Commission-approved tariff service to municipalities for the operation of automated traffic signal (ATS) lights on its E2 Rate Schedule (Bellini, 6T 3101, 3103).

DTE Electric's E1 Option I Rate reflects recovery of costs associated with the Company's ownership, maintenance and provision of energy to its portfolio of light emitting diode (LED), high pressure sodium (HPS), mercury vapor (MV), and metal halide lighting. Option II (closed to new customers since 2009) is for street lighting systems owned by municipalities, but maintained by the Company. Option III is where the municipality owns and maintains the system, and the Company provides only energy. DTE Electric's D9 Rate Schedule reflects recovery of costs associated with the Company's ownership, maintenance and provision of energy to its portfolio of approximately 24,000 commercial and 9,000 residential OPLs. DTE Electric's E2 rate schedule reflects the recovery of costs for the production and distribution of energy for ATS lights owned and maintained by municipalities and other public authorities (Bellini, 6T 3103-3105).

The Company decided to sunset its active maintenance and support for HPS fixtures effective the earlier of January 1, 2025, or the depletion of remaining HPS inventory, which the Company stopped purchasing in November 2023. This decision was based on the continued movement toward LED technology, and key lighting vendors indicating that they will be, or are considering, phasing out their HPS product lines in 2024. The timing will allow customers to be informed and address any concerns that they might have, and the use of remaining HPS inventory

will support an orderly transition to LEDs. To further support the transition, the Company also decided to offer a $65 per light HPS labor credit (the same as the MV labor credit) starting in 2024 for those municipalities that have decided to proactively convert to LEDs in projects that have not yet begun. The Company also proposes corresponding changes to E1 Option 1 and D9 tariff language (Bellini, 6T 3105-3107).

The Commission previously rejected MI-MAUI's proposal that the Company stop charging CIAC for HID-LED conversions (December 1, 2023 Order in Case No. U-21297, p 139). MI-MAUI again proposes that the Commission "should deny the proposal to continue a CIAC for group LED conversions" (Bunch, 6T 4303). The Company disagrees because the existing CIAC approach, approved by the Commission for converting Company-owned mercury vapor (MV) lights, remains valid. This method, which includes the now outdated high-pressure sodium (HPS) lights, should continue in accordance with the established practice for MV light replacements, since both MV and HPS lights are HID. MI-MAUI presented nothing to demonstrate that the Company departed from the approved practice, or to justify changing the practice. Therefore, the Commission should again reject MI-MAUI's proposal to stop charging CIAC for project conversions (Bellini, 6T 3102-3103, 3145, 3151-55).[143]

MI-MAUI further proposed to create a "bill credit method" to refund CIAC to customers that converted lighting systems to LEDs (Bunch, 6T 4308). The Company disagrees because refunding past years of customer-funded CIAC to customers who chose to convert over the years would be inconsistent with Commission-approved policy (as indicated above), and would result in millions of dollars being rate-based and socialized among lighting customers, which would have an

[143] There continues to be robust and proactive HID to LED conversions by municipalities (Bellini, 6T 3103, 3177-78).

adverse effect on all municipal streetlighting rates because LEDs now represent almost 70% of all Company-owned municipal streetlights (Bellini, 6T 3105, 3155-58).

The Commission should similarly reject Ann Arbor's proposal that "[c]ommunities who proactively converted their streetlights to LEDs and paid a CIAC up front should receive a credit so they are not paying both for the entirety of their own conversions and a portion of others" (Stults, 6T 4276). In addition to the discussion above, there is no basis for witness Stults' suggestion that a municipal customer choosing to convert to LEDs is paying for both its own conversion and a portion of others. Cost of reactive conversions (including those performed in Ann Arbor) are socialized among all municipalities, and municipal project conversion costs to convert a specific municipality's lights to LED are excluded from impacting all other municipal customers (including Ann Arbor) that would otherwise be reflected through higher rates. Also, Ann Arbor received a SEMCOG-funded grant for 80% of their total project HID-LED conversion costs (Bellini, 6T 3149, 3181).

Exhibit A-16, Schedule F3 Revised shows the present and proposed rate design and corresponding revenues by rate schedule, based on the billing determinants for the projected test year. The lighting rates approved in Case No. U-21297 reflect a monthly energy charge, both non-capacity and capacity energy, and a luminaire charge (Bellini, 6T 3132-33).

The Commission previously directed the Company to work with interested stakeholders to develop a streamlined streetlight outage report request process, a standardized report format, data protocols, and delivery method, and to update its E1 tariff regarding customer requests for outage reports (December 1, 2023 Order in Case No. U-21297, p 373).

The Company proposes to clarify the tariff language to reflect that outage reporting will be available only for E1 Option 1 customers, which is appropriate because these are the only E1 streetlights that the Company owns, operates, and maintains. Company witness Bellini also reported

that the Company is working toward development of an outage report, and provided an overview of the Company's new outage management system, which will help to streamline the process of developing the outage reports (Bellini, 6T 3116-17).

MI-MAUI witness Bunch proposed to adjust the Company's streetlighting sales forecast based on "the Night Patrol outage rate . . . [and] the number of HID fixtures remaining under the E1, Option I rate," resulting in a recommended "reduction of 3,308,045 kwh, equivalent to 4.06% of DTE's unadjusted forecast for E1, Option I streetlights" (Bunch, 6T 4312-13). The Company agrees with the proposal to adjust the sales forecast based on the 2023 Night Patrol outage rate; however, the Company has already reduced its sales forecast by 3.25% as the Commission ordered in Case No. U-21297. Therefore, the total adjustment should be 0.81% (4.06% based on night patrol outages minus 3.25% ordered in Case No. U-21297). Also, Night Patrols targeting communities experiencing higher-than-average outage events has the potential to skew the outage percentage. Therefore, the Company proposes to work with Staff and MI-MAUI to establish a methodology that provides for a long-term, sustainable approach to approximate system-wide outages (Bellini, 6T 3145-46, 3159).

Company witness Bellini supported the proposed allocation of costs reflected in the various E1 Option Rate Schedule luminaire charges (6T 3134-37), testifying: "The methodology utilized in the lighting model to allocate each of the individual cost of service components discretely, rather than in total, more accurately reflects the cost to provide lighting service to underground and overhead assets as well as the various lighting technologies. The usage of the eight separate asset subaccounts for allocation of the capital-related costs results in more accurate rate setting based upon both how the lights are fed as well as the lighting technology, wattage and luminaire investment" (Bellini, 6T 3137). He also explained how E1 Option II and Option III charges were developed, and supported the Company's proposed E1 rates as appropriately continuing the gradual

move to rates that are entirely based on cost of service (Bellini, 6T 3137-39). The Company's proposed D9 rates similarly allocate costs and continue the gradual movement toward cost-based rates (Bellini, 6T 3139-40). Mr. Bellini also explained and supported Rate Schedule E2 charges (6T 3140-41).

MI-MAUI witness Bunch supported the Company's recovery of outage restoration costs, but further proposed that the Commission "order the Company to provide a proposed reporting scheme within three months of its final order in this case, for review and discussion with Staff and intervenors. The proposal should provide a taxonomy of root outage causes, causes of delays in restoration, cost breakdowns and other data to be provided" (Bunch, 6T4322-23).

The Company appreciates MI-MAUI's support regarding cost recovery, but disagrees with its reporting proposal for two reasons. First, the proposal is based on an incorrect premise that the Company's outage performance continues to deteriorate, which it has not done.[144] Second, witness Bunch overstated the capabilities of the Company's new outage management (OMS) system, Kloudgin. Therefore, the Commission should reject MI-MAUI's reporting proposal. The Company instead proposes a Staff-facilitated workshop where the Company, Staff, and MI-MAUI can discuss the Company's OMS capabilities, the potential for enhancements, and whether such investments would be prudent relative to their benefits (Bellini, 6T 3103, 3111, 3110, 3147, 3166-70; Exhibit A-25, Schedule O1).

Ann Arbor witness Naheedy inaccurately suggested (apparently based on materials submitted by his predecessor two years ago in Case No. U-20836), that the Company's outage restoration performance is poor, with DTE Electric-owned streetlights in Ann Arbor having an outage rate of 26% compared to Ann Arbor's City-owned streetlights having an outage rate of 9%

[144] For example, despite challenges from COVID and catastrophic storms, the Company has decreased its outage duration from 5.22 days in 2021 to 4.16 in 2023 (Bellini, 6T 3166-67; Exhibit A-25, Schedule O1).

(Naheedy, 6T 4224). To the contrary, the Company conducted eight night patrols that canvassed all of Ann Arbor's Company-owned municipal streetlights between 2020 – 2023. The outage results from those eight patrols ranged from 2% to 8% (Bellini, 6T 3148, 3178).

H. Nuclear Surcharge

The nuclear surcharge recovers costs for Fermi 2 site security, radiation protection, nuclear decommissioning, and Low-Level Radioactive Waste (LLRW) disposal. These activities are required for Fermi 2's safe and secure operation. As in past cases, DTE Electric proposes to increase the nuclear surcharge only with respect to inflation for the Site Security and Radiation Protection portion of the surcharge. The Nuclear Decommissioning funding and LLRW disposal funding are unchanged. The resulting nuclear surcharge is $40.1 million for the projected test period (Exhibit A-20, Schedule J1, page 1, line 5, column (b)), which is an increase of approximately $1.2 million from the currently-authorized nuclear surcharge. The Company's proposed nuclear surcharge is reasonable and prudent, and therefore should be approved (Davis, 6T 1877-79. See also Willis, 6T 2585; Exhibit A-16, Schedule F6).

I. Distributed Generation (DG) Tariff (Rider 18)

The Commission previously approved the Staff's method to calculate the outflow credit for customers taking Distributed Generation (DG) service Rider 18 (November 18, 2022 Order in Case No. U-20836, p 444). Exhibit A-16, Schedule F7 calculates the outflow credits using the same methodology that the Commission again approved in Case No. U-21297. The PSCR factor is not included (for administrative convenience due to the frequent changes in the PSCR factor); however, when calculating the actual outflow credit applied to customer bills, the Company will add or subtract the current PSCR factor (Willis, 6T 2594-95).

XI. OTHER PROPOSALS[145]

A. Reliability Performance and Capital Investment

Ann Arbor witness Stults recommended that "the Commission use its authority to consider the value of DTE's service to better tie DTE's financial performance to its customers' experience in this case – through denying a large portion of DTE's requested rate increase and taking its performance into consideration when determining an appropriate rate of return ('ROE'). (Stults, 6T 4251-52).

Witness Stults made no specific recommendation, so it is unclear what she might have in mind. As a general response, however, the Company is committed to improving reliability by reducing power outages by 30%, and cutting outage time in half over the next five years (30% fewer…50% faster…by 2029). This would result in better than industry median performance by 2029 for Average System Availability Index and All-Weather System Average Interruption Duration Index (SAIDI). This commitment can be met only with significant investments in the Company's infrastructure supported by timely recovery of those investments. Therefore, "denying a large portion of DTE's requested rate increase" as witness Stults suggested would have a detrimental impact on reliability, which would be the opposite effect of what she claims to want. Ann Arbor is also participating in pending Case Nos. U-21400 (related to Performance Based Ratemaking (PBR)), where the Commission is already exploring how to strengthen the ties between the Company's reliability performance and its financial outcomes. Therefore, the Commission should reject Ann Arbor's recommendations in this case, and instead continue to address reliability

[145] See generally supra, Section II. History of Proceedings – *DTE Electric* – Foley, Kryscynski, Elliott Andahazy, Willis, Hill, Fix; *CUB-MN* – Denzler; *Attorney General* -- Coppola; *Ann Arbor* – Stults; *DAAO* – Koeppel; *GLREA* – Rafson; *MI-MAUI* – Bunch, Stewart; *CEO* - Tan

performance through Case No. U-21400 (Foley, 2T 72-72,143-44). See also, section VI. C (ROE) and VIII. A (IRM).

The Company further notes that based on the Interruption Cost Estimator (ICE) calculator, which was developed by the Lawrence Berkeley National Laboratory, the forecasted reliability improvements could generate more than $15 billion of positive economic impact (Foley, 2T 74). Ann Arbor witness Stults asserted that "the Company is planning to invest a total of $16 billion between 2024 and 2028, so an estimated $15 billion in positive economic impacts will result in a net loss of $1 billion" (Stults, 6T 4249). The comparison and resulting conclusion are incorrect. The $16 billion represents total Company 2024-2028 capital investment in both cleaner generation and distribution infrastructure. The more than $15 billion of positive economic impact estimated by the ICE calculator is driven by reliability benefits realized through only a portion of the investment (Foley, 2T 145).

B. Environmental Justice in System Reliability and Distribution Planning

Consistent with the Company's DGP and the Commission's guidance, DTE Electric developed reliability data by quartile for SAIFI and SAIDI by census tract across the Company's service territory (geographically represented at Kryscynski, 3T 374-77). The Company also determined vulnerable census tracts using the draft MiEJScreen tool score, at 5% gradations consistent with Commission guidance (December 1, 2023 Order in Case No. U -21297, p 93).[146] The 483 census tracts identified as vulnerable communities (composite draft MiEJScreen score at or above 80th percentile) had better reliability than the system average in SAIFI and SAIDI in both All-Weather and Non-MEDs. All-Weather and Non-MEDs SAIFI is lower than the system average

[146] Thus, it was inaccurate for DAAO witness Koeppel (at 6T 4411) to suggest that the Company's equity analysis is "flattened by a binary assessment of vulnerable vs. not vulnerable tracts" (Kryscynski, 3T 450).

in every year and every vulnerable community gradient. For Non-MED SAIDI, the vast majority of years and vulnerable community gradients are better than the system average. All-Weather shows more year-gradient combinations above the system average, but even for this metric, the majority of instances are better than the system average (Kryscynski, 3T 378-384)

The Company also evaluated some of its largest distribution investment projects and programs (4.8kV Hardening, 4.8kV Conversion, and tree trimming) and found that the investments are supporting vulnerable customers and communities. For example, nearly half a billion dollars has been invested in the 4.8kV hardening program since 2018, with 85% of the work occurring in vulnerable communities, resulting in safety and reliability improvements including reductions in the frequency and duration of outages and fewer downed wires, through the program's clearing of rights of way, equipment upgrades, and removal of arc wire (Kryscynski, 3T 385-86, 455; Elliott Andahazy, 4T 923, 927-29; Exhibit A-23, Schedule M8, 2023 DGP, section 12.2).

The Company's proposed 2024-2025 investments in conversions, hardening and tree trimming (61%, 90%, and 28% respectively) are similarly planned to benefit vulnerable communities. DTE Electric's continuing significant investments in vulnerable communities is further reflected by breakdown of investment by year at 5% EJ gradations (Kryscynski, 3T 386-92). These investments are consistent with the Company's commitment to improving reliability in vulnerable communities, which is further demonstrated by the Company including EJ scoring in the updated GPM so projects in more vulnerable areas will receive a higher score and have a better chance of being selected for investment (Kryscynski, 3T 392-93).

DAAO witness Koeppel suggested that the draft MiEJScreen tool is not "sufficiently granular" regarding "individual neighborhoods, households or customer subgroups within each tract" (6T 4410-11). He also suggested that the Company do more tracking and reporting of EJ-related metrics (Koeppel, 6T 4416), as did CEO witness Kenworthy (6T 3209). The Company

disagrees. The draft MiEJScreen tool is appropriate to use for distribution analysis because (1) it was developed with extensive input from Michigan stakeholders, including experts in the EJ Community, (2) it is maintained by the State of Michigan, and (3) it includes a breadth of socioeconomic and environmental factors in its EJ impact scoring. The census tract information is also granular enough for the Company to use in reliability planning. More granular breakdowns would not be particularly useful because grid solutions typically need to be addressed at the circuit or substation level. Additional EJ analysis is similarly not needed at this time. The Company already considers EJ with respect to investments, as indicated above. The Company will also continue to collaborate with stakeholders as EJ issues, data, tools, and analysis continue to evolve (Kryscynski, 3T 372, 449-50).

DAAO witness Koeppel also criticized CODI investments, and suggested that they somehow "count" in what he asserted was "binary bucketing" of vulnerable census tracts (6T 4411-12). Witness Koeppel's "binary" description is inaccurate as indicated above, and his description of CODI investments is similarly inaccurate and unsupported. Contrary to witness Koeppel's apparent misunderstandings, the Company's evaluates projects and programs through the GPM using multiple factors including reliability, safety, and EJ. This results in a diverse and balanced portfolio of investments that support multiple grid objectives for all customers, including those who are the most vulnerable. Also contrary to witness Koppel's suggestion that CODI investments are not sufficiently EJ focused, his own testimony includes a map (at Koeppel, 6T 4413) showing that the vast majority of the CODI area has an MiEJScreen tool score of over 80, and well over half of the area has a score over 90. The Company uses the description of "vulnerable" to describe customers in geographic areas with 80-100 MiEJ Screen scores and "non-vulnerable" to discuss those with scores less than 80. The highest possible score for an area is 100. (Kryscynski, 3T 450-52).

DAAO witness Koeppel further suggested that Table 14 ("Residential Customers by EJ Gradations") in Company witness Kryscynski's direct testimony (at Kryscynski, 3T 384) "indicates a strong potential that population density is a significant factor in reliability performance" (Koeppel, 6T 4413). Such a conclusion cannot accurately be drawn from Table 14 because it does not indicate the number of census tracts within each grouping, or the square miles associated with each grouping. Also, in any given area, population could be spread evenly or clustered in one location, adding further complexity to the density issue (Kryscynski, 3T 453).

GLREA witness Rafson asserted that "[a]ccording to the Center for Disease Control [CDC], a 1% drop in socioeconomic status results in waiting 170 minutes longer on average to restore power" (Rafson, 6T 4870). The Company first notes for accuracy that the asserted connection between socioeconomic status and power restoration was the work of authors Ji and Ganz, not the CDC. The CDC has a database similar to Michigan's MiEJScreen tool. The article referred to data for 15 million customers in 588 U.S. counties between 2017 and 2020. The Company's EJ analysis appropriately uses more recent data, the MiEJScreen tool, and data for the Company's specific customers instead of the broader U.S. population. The article also went on to suggest hypotheses for the longer restoration times, including that the referenced communities might be in predominately older neighborhoods where energy infrastructure might require more significant repairs. This is consistent with the discussions above (in section V. B. 4. viii) that the Conversion and Hardening programs are necessary to support improving reliability for areas served by the Company's oldest 4.8kV infrastructure (Kryscynski, 3T 454).

CEO witness Tan indicated that he provided an updated regression analysis with 2023 reliability data (Tan, 6T 3275-76).[147] Instead, the updated regression analysis is fundamentally

[147] In Case No. U-21297, CEO witness Tan proposed a regression analysis that met considerable criticism.

different and inherently flawed because witness Tan used municipal-level data as census tract data. Census tracts can include several municipalities, so many census tracts were included multiple times in the data set. Correcting and re-running the updated analysis (as well as running the old analysis with updated dated) reduces the statistical significance of results. The Company is actively working on EJ regression analysis with Witness Tan and Staff, and anticipates that it will be included in the 2025 DGP. The Company also continues to collaborate with all stakeholders to create a robust regression analysis that receives universal support (Kryscynski, 3T 455-57).

C. Contributions in Aid of Construction (CIAC) and Standard Allowance Table

The PFD in Case No. U-21297 relevantly stated:

> 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. [U-21297 PFD, p 793.]

The Commission agreed (Case No. U-21297 Order dated December 1, 2023, p 315). Accordingly, the Company proposes updates to the CIAC standard allowance table for customers with new or expanded load greater than 1,000 kW consistent with the method approved in Case No. U-20836, and consistent with the Order in Case No. U-21297 (Willis, 6T 2614; Hill, 6T 3056-58; Exhibit A-16, Schedule F8, Section C6.2).

The Company also proposes to eliminate Section C6.1(16) of the Company's rate book, which is the waiver of CIAC for certain customers participating in the Charging Forward program (Bennett, 6T 1968; Willis, 6T 2614-15).

CUB-MN witness Denzler recommended:

> To ensure that implemented CIAC accurately reflects the current costs of construction and desired connections, I recommend the Commission order a report in the next rate case proceeding detailing the impact of the CIAC changes. This should include a review of the new business construction costs and CIAC received,

> with comparison to historic and projections of future new business construction costs and CIAC received.
>
> Additionally, the Commission should ensure that CIAC sees regular updates in the future so that it does not drift so far from actual costs again. To this end, I recommend the Commission order a regular review of CIAC costs. I recommend a review cadence of at least once every two years, but certainly no more than once every five years. [Denzler, 6T 3777.]

The Company disagrees with the report recommendation because the information is already provided in the Company's publicly-available Exhibit A-12, Schedule B5.4 for each rate case. The Company agrees it is reasonable and prudent to have regular CIAC reviews, and believes a five-year cadence is appropriate (Hill, 6T 3091).

Ann Arbor witness Stults proposed to limit CIAC for customers on 4.8kV circuits, asserting:

> I recommend the CIAC be no more than it would be if the site were served by a 13.2kV system – that is the Company should cover the costs for increasing the capacity in the area by 2.5 times before any CIAC is charged to the developer for increased capacity. A developer should not have to pay the cost differential necessary to increase the capacity from that of a 4.8kV system to that of a 13.2 kV system. Requiring the developer to cover this cost differential is unreasonable because it unfairly favors projects in newer communities and discourages increasing development density in older cities like Ann Arbor, Detroit, Grosse Pointe, and Highland Park that have not yet been upgraded to a 13.2kV system. However, ratepayers as a whole benefit from increased density by reducing the infrastructure needed to serve the customer base. Thus, it is to everyone's benefit not to adopt a policy that effectively encourages urban sprawl. [Stults, 6T 4269.]

The Company disagrees, and is not aware of situations in which similarly-situated customers on the 4.8kV and 13.2kV systems have paid substantially different CIAC fees based on the voltage of the system to which they are connected. There are many factors such as existing circuit and/or substation conditions, as well as customer load characteristics, which contribute to the potential CIAC a developer is responsible for because of the impact that their load addition has on the system, and thus other customers. Not charging developers for their share of required system upgrades and extensions would shift that burden onto all customers, including the most vulnerable (Hill, 6T 3092. See also, Deol, 5T 1269-70).

D. Voluntary Separation Incentive Program (VSIP)

The AG proposed to reduce the Company's O&M expense by $10.1 million based on employee reductions in 2024, reasoning that this is half of the Company's projection of $20.3 million of estimated potential savings in 2025 (Coppola, 6T 3687-88). The Company disagrees. Company witness Fix explained that it would be premature to include any savings from the VSIP in the Company's revenue requirement:

> The purpose of the VSIP was to realign the workforce to support the changing nature of the Company's work and how the work is done, including an increased focus on infrastructure investments, cybersecurity, and the clean energy transition. Therefore, the Company continues to assess the need to fill key positions which will impact any actual savings that may potentially be realized in 2025. While the Company has made certain assumptions about the number of open positions as a result of the VSIP that will be filled in its estimated savings, these estimated savings will continue to evolve as decisions regarding the actual number of positions filled are made throughout the remainder of 2024. Rather than relying on an estimate of potential savings that may be created by the VSIP, it is more prudent to wait until any savings are actually realized which can then be reflected in the Company's future revenue requirements. [Fix, 6T 2911-12.]

The AG's proposal is also unreasonably and illegally one-sided in seeking a cost reduction for potential savings in 2025, where the Company has not sought to recover the $30.6 million in costs related to the separation payments in 2024 (Fix, 6T 2912).[148]

There is similarly no merit in CUB-MN witness Denzler's proposal to reduce the Company's O&M recovery by $32.2 million to reflect labor and related savings of the employees that departed under the VSIP, but not any costs of the employees who will be required to fill key positions (Denzler, 6T 3777-80). Any reduction would be premature, as discussed above. CUB-

[148] The Michigan Supreme Court has recognized that creating rates that recognize *reductions* in certain costs while ignoring the *increase* in other costs, violates the due process rights of utilities. The Court cited with approval the conclusions of a circuit court judge granting an injunction against such unlawful rates in *Michigan Consolidated Gas Company v Public Service Comm*, 389 Mich 624, 633; 209 NW2d 210 (1973) ("Certainly at first blush it would appear to anyone steeped in 'due process' considerations that it is grossly unfair to include certain items of decreased cost in rate determination while at the same time to exclude items of increased cost.")

MN's proposal is also even more one-sided (and therefore unreasonable and unlawful) than the AG's proposal (Fix, 6T 2913-14).

CUB-MN witness Denzler asserted that it would be unreasonable for "rate payers to bear the risk for the volatility of [the Company's] staffing levels" (Denzler, 6T 3779). This assertion apparently is based on the incorrect premise that the Company offered the VSIP solely to reduce costs, instead of to realign its workforce to meet changing needs, as discussed above. In April 2024, the Company expected that it would need to hire 184 new employees to fill positions consistent with the realignment of its workforce. Although the number and costs of employees required to meet the Company's changing workforce needs continues to evolve, it is patently unreasonable and contrary to the record to assume that the number of employees hired will be zero (Fix, 6T 2913-14).

Therefore, the proposals to reduce the Company's O&M recovery based on the VSIP should be rejected as premature, unreasonable, and unlawful.

E. Nanogrids and Microgrids

GLREA witness Rafson described several apparent benefits of microgrids and nanogrids, and recommended that the Commission "should specifically allow nanogrids and microgrids" (6T 4878).

With regard to nanogrids, all of the technologies described by witness Rafson are available to customers under current Company tariffs and require no changes to the Company's tariffs (Willis, 6T 2640).

There are legal and regulatory concerns, however, with witness Rafson's further suggestions that microgrids include service between multiple individual customers, islanded groups of customers, and "submeters" across neighborhoods (Willis, 6T 2640). A full examination is beyond

the scope of this discussion (and perhaps witness Rafson's intent), but the concerns generally relate to the concept of what is a "utility"[149] and the nature of Michigan utility regulation.[150]

Witness Rafson's proposal also impacts tariffs and involves operational and safety issues. Therefore, if the Commission decides to pursue the proposal, then it should be addressed in a separate interconnection rules forum (Kryscynski, 3T 468).

F. Community Coordination

The Commission previously ordered: "In its next general rate case, DTE Electric Company shall demonstrate its efforts to improve communication and coordination with local governments regarding construction activities, as described in this order" (December 1, 2023 Order in Case No. U-21297).

Accordingly, the Company outlined how it frequently, through a variety of methods, communicates and coordinates with municipalities to discuss the details of projects located within communities, benefits, and collaboration opportunities. The Company also outlined its ongoing efforts focused on improving communication and coordination with municipalities and county road commissions, including identifying preferred methods of receiving planning and construction efforts (Kryscynski, 394, 458).

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[149] For example, in *Panhandle Eastern Pipeline Co v Public Service Comm*, 328 Mich 650, 664; 44 NW2d 324 (1950), *aff'd* 341 US 329; 71 S Ct 777; 95 L Ed 993 (1951), Panhandle contracted to furnish gas directly from the pipeline's facilities to one Michigan customer (Ford Motor Company), but also indicated a willingness to provide gas to other industrial customers in the future. The Michigan Supreme Court affirmed the MPSC, which held that Panhandle was a public utility because it undertook the service of natural gas to ultimate customers in Michigan.

[150] For example, under 1929 PA 69 (MCL 460.501 *et seq*, "Act 69"), a public utility must obtain a certificate of public convenience and necessity from the MPSC before it may construct or operate any public utility plant or system or provide any public utility service in an area where another public utility is already engaged in rendering the same sort of service. Act 69 provides: "The term 'public utility,' when used in this act, means persons and corporations, other than municipal corporations, or their lessees, trustees and receivers now or hereafter owning or operating in Michigan equipment or facilities for producing, generating, transmitting, delivering or furnishing gas or electricity for the production of light, heat or power to or for the public for consumption." MCL 460.501

MI-MAUI witness Bunch suggested that the Company should have provided more detail regarding its coordination activities (6T 4357), and Ann Arbor witness Stults suggested that the Company should do more to coordinate (6T 4266).

In response, Company witness Kryscynski provided examples of the types of community coordination and outreach that the Company performs (3T 459-60), and discussed the Company's continuing efforts to improve community coordination, including Witness Stults' indicated concern about early-stage project coordination (3T 460-61). The Company also has processes to coordinate at a county and regional level, and at a statewide level (3T 461-64). Mr. Kryscynski also responded to related assertions by MI-MAUI witness Bunch and Ann Arbor witness Stewart (3T 466).

Therefore, the Company satisfied the Commission's directive to demonstrate its efforts to improve communication and coordination with local governments regarding construction activities, and criticisms of that response as well as the Company's efforts do not merit any further action by the Commission.

MI-MAUI witness Bunch further suggested that the Commission should "presume that 10% of the costs of electric infrastructure projects that involve excavation in the public right of way or easements are not recoverable unless the Company can show neither DTE Gas nor the government plans potential work in the same area, or the Company made reasonable attempts to coordinate work with such projects" (6T 4363-64).

The Company disagrees because the proposed presumption is unfounded as indicated above, as well as inconsistent with regulatory law including evidentiary burdens as indicated in section III. The same can be said for the proposed "reasonable attempts" standard, which would also be difficult to apply with subjective opinions adding to already-unwieldy rate cases. Moreover, although work coordination is preferable, there are many reasons why it might not be possible. For example, the Company's investment work might need to be done sequentially and might not be able to be aligned

perfectly with the municipality. There also might be regulatory requirements that do not allow for timeline adjustments. There also might be times due to unforeseen circumstances (for example, new business work) when a project needs to be built on a short timeline, which might not allow much time for coordination. Therefore witness Bunch's proposed presumption should be rejected (Kryscynski, 3T 465).

G. Miss Dig

Staff made recommendations on record keeping and meeting with Staff regarding Miss Dig in Case No. U-21297. The Company agreed, and the Commission ordered them (December 1, 2023 Order in Case No. U-21297, pp 355, 376). Accordingly, the Company updated the formatting and data in the Miss Dig damage report. The Company also continues to meet with Staff on a bi-monthly basis, and otherwise actively work on complying with the recommendations (Hill, 6T 3059-60).

XII. 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, and this Initial Brief (including Attachments A and B) approving rates that will recover the Company's revenue deficiency of approximately $446.1 million, based on a January 1, 2025 through December 31, 2025 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 January 28, 2025 in the manner described in the Company's Application, testimony, exhibits, and this Initial Brief (including Attachments A and B);

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 continuation, extension, and expansion of the IRM;

J. Approving the SRCSM as proposed by the Company;

K. Approving all proposed pilot programs as requested by the Company;

L. Approving all proposed regulatory accounting treatments as requested by the Company;

M. Approving the capacity charge calculated by the Company, which is based on the methodology utilized in Case No. U-21297, 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 and this Initial Brief (including Attachments A and B); and

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

Respectfully submitted,

DTE ELECTRIC COMPANY
Legal Department

Jon P. Christinidis Digitally signed by Jon P. Christinidis Date: 2024.10.03 15:40:12 -04'00'

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Dated: October 3, 2024

DTE Electric Company
Computation of Revenue Deficiency
Projected 12 Month Period Ending December 31, 2025
($000)

MPSC Case No. U-21534
Initial Brief
Attachment A

Line No.	(a) Description	(b) Company Position As Filed	(c) Adjustments	(d) Initial Brief Position	(e) MPSC Staff Position As Filed	(f) Difference
1	Rate Base (1)	$ 22,107,989	$ (40,470)	$ 22,067,519	$ 21,967,013	$ 100,506
2	Adjusted Net Operating Income (2)	1,087,100	5,111	1,092,211	1,174,574	(82,362)
3	Rate of Return (3)	5.9231%	-0.0008%	5.9223%	5.6598%	0.2625%
4	Income Requirements	1,309,478	(2,573)	1,306,905	1,243,299	63,606
5	Income Deficiency (Sufficiency)	222,378	(7,684)	214,694	68,725	145,968
6	Revenue Conversion Factor (4)	1.3496	-	1.3496	1.3496	-
7	**Rev Deficiency / (Sufficiency)**	**$ 300,129**	**$ (10,371)**	**$ 289,758**	**$ 92,754**	**$ 197,004**
8	Tree Trim Surge (5)	18,786	-	18,786	10,133	8,653
9	Monroe Regulatory Asset (5)	137,518	-	137,518	136,947	572
10	**Revenue Deficiency / (Sufficiency) - Total**	**$ 456,434**	**$ (10,371)**	**$ 446,063**	**$ 239,834**	**$ 206,229**

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

Line No.	(a) Description	(b) Company Position As Filed	(c) Adjustments	(d) Initial Brief Position	(e) MPSC Staff Position As Filed	(f) Difference
1	Plant in Service	$ 24,872,100	$ (27,152) (1)	$ 24,844,948	$ 24,728,561	$ 116,388
2	Plant Held for Future Use	22,532		22,532	22,532	-
3	Construction Work in Progress	2,450,590		2,450,590	2,450,590	-
4	Acquisition Adjustments	83,332		83,332	83,332	-
5	Total Utility Plant	27,428,555	(27,152)	27,401,403	27,285,015	116,388
6						
7	Less: Depreciation Reserve	6,777,289	(2,180) (2)	6,775,109	6,764,051	11,058
8						
9	Net Utility Plant	20,651,266	(24,972)	20,626,294	20,520,964	105,330
10						
11	Net Capital Lease Property	6,051		6,051	6,051	-
12	Net Nuclear Fuel Property	162,350		162,350	162,350	-
13						
14	Total Utility Property and Plant	20,819,666	(24,972)	20,794,695	20,689,365	105,330
15						
16	Less: Capital Lease Obligations	7,049		7,049	7,049	-
17						
18	Net Plant	20,812,617	(24,972)	20,787,646	20,682,316	105,330
19						
20	Allowance for Working Capital	1,295,372	(15,499) (3)	1,279,873	1,284,697	(4,824)
21						
22						
23	Rate Base	$ 22,107,989	$ (40,470)	$ 22,067,519	$ 21,967,013	$ 100,506

(1) (2) Capital adjustments to Plant and Depreciation Reserve:

	Net Cap Ex	Plant Adj. (1)	Accum. Depr. (2)	
DO: 2023 Underspend	$ (25,202)	$ (25,202)	$ (1,985)	6T 3087
IT: MIGP Scope 3 Billing/Enrollment	(3,900)	(1,950)	(195)	6T 2308
	$ (29,102)	$ (27,152)	$ (2,180)	

(3) Working Capital adjustment:

Operational Incentives Reg Asset	$ (106)	AGDE-3.128a
Non-Utility Other A/R	(6,111)	6T 4888, JJH-1.2
Deferred Incentive Compensation	(9,282)	6T 1574
	$ (15,499)	

DTE Electric Company | **MPSC Case No. U-21534**
Adjusted Net Operating Income | **Initial Brief**
Projected 12 Month Period Ending December 31, 2025 | **Attachment A**
($000) | **Page 3 of 4**

Line No.	(a) Description	(b) Company Position As Filed	(c) Adjustments	(d) Initial Brief Position	(e) MPSC Staff Position As Filed	(f) Difference
1	**Operating Revenues**					
2	Sales Revenues	$ 5,465,416	$ -	$ 5,465,416	$ 5,468,651	$ 3,235
3	Other Operating Revenue	-		-	-	-
4	Fuel and Purchased Power	1,354,105		1,354,105	1,354,105	-
5	Net Margin	4,111,311	-	4,111,311	4,114,546	3,235
6						
7	**Operating Expenses**					
8	Operations and Maintenance Expenses	1,266,950	(5,110) (1)	1,261,840	1,161,522	(105,429)
9	Depreciation and Amortizations	1,266,245	(1,426) (2)	1,264,819	1,253,974	(12,270)
10	Property Taxes	328,772	(677) (3)	328,095	328,656	(117)
11	Other Taxes	53,180		53,180	53,180	-
12	Total Operating Expenses	2,915,148	(7,213)	2,907,934	2,797,332	(117,816)
13						
14	**Operating Income**	1,196,164	7,213	1,203,377	1,317,214	121,051
15						
16	**Other Operating Income Adjustments**					
17	Allow. For Funds Used During Constr	55,969		55,969	55,969	-
18	Amortization of Loss on Reacquired Debt	(2,244)		(2,244)	(2,244)	-
19	Other Income	6,400		6,400	6,400	-
20	Total Operating Income Adjustments	60,126	-	60,126	60,126	-
21						
22	**PreTax Adjusted Net Operating Income**	$ 1,256,290	$ 7,213	$ 1,263,503	$ 1,377,340	$ 121,051
23						
24	State Income Taxes	61,413	504	61,917	69,462	8,049
25	Federal Income Taxes	107,776	1,598	109,374	133,304	25,528
26						
27	**Net Operating Income**	$ 1,087,100	$ 5,111	$ 1,092,211	$ 1,174,574	$ 87,474

(1) Operations and Maintenance

ACPP/TOD Amortization	$ (110)	AGDE-4.156b
Uncollectible Expense	(3,800)	6T 2383
Amortization of Deferred Incentive Comp.	(1,200)	6T 1574
	$ (5,110)	

(2) Depreciation and Amortization

DO: 2023 Underspend	$ (1,036)	6T 3087
IT: MIGP Scope 3 Billing and Enrollment project	(390)	6T 2308
	$ (1,426)	

(3) Property Taxes

DO: 2023 Underspend	(677)	6T 3087
IT: MIGP Scope 3 Billing and Enrollment project	-	6T 2308
	$ (677)	

DTE Electric Company
Rate of Return Summary
Projected 12 Month Period Ending December 31, 2025
Based on Average Rate Base
($000)

MPSC Case No. U-21534
Initial Brief
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
	Filed Position (Test Period Average Basis)								
1	Long-Term Debt	$ 8,663,922	50.00%	39.19%	4.24%	2.119%	1.66%	100.000%	1.660%
2	Preferred Stock	0		0.00%	0.00%	0.000%	0.00%	134.964%	0.000%
3	Common Shareholders' Equity	8,673,528	50.00%	39.23%	10.50%	5.250%	4.12%	134.964%	5.560%
4	Total	17,337,450	100.00%			7.369%			
5									
6	Short-Term Debt	509,454		2.30%	5.76%		0.13%	100.000%	0.133%
7									
8									
9									
10	Job Development - ITC - Debt	15,742		0.07%	4.24%		0.00%	100.000%	0.003%
11	Job Development - ITC Equity	15,742		0.07%	10.50%		0.01%	134.964%	0.010%
12	Total Job Development - ITC	31,485							
13									
14	Deferred Income Taxes (Net)	4,229,600		19.13%	0.00%		0.00%		0.000%
15									
16	Total	22,107,989		100.00%			5.92%		7.366%
	Initial Brief Position (Test Period Average Basis)								
17	Long-Term Debt	$ 8,663,922	49.97%	39.19%	4.24%	2.117%	1.66%	100.000%	1.660%
18	Preferred Stock	0			0.00%	0.000%	0.00%	134.964%	0.000%
19	Common Shareholders' Equity	8,673,528	50.03%	39.23%	10.50%	5.253%	4.12%	134.964%	5.560%
20	Total	17,337,450	100.00%			7.370%			
21									
22	Short-Term Debt	509,454		2.30%	5.73%		0.13%	100.000%	0.132%
23									
24									
25									
26	Job Development - ITC - Debt	15,742		0.07%	4.24%		0.00%	100.000%	0.003%
27	Job Development - ITC Equity	15,742		0.07%	10.50%		0.01%	134.964%	0.010%
28	Total Job Development - ITC	31,485							
29									
30	Deferred Income Taxes (Net)	4,229,600		19.13%	0.00%		0.00%		0.000%
31									
32	Total	22,107,989		100.00%			5.92%		7.365%

DTE Electric Company
Rate of Return Summary
Projected 12 Month Period Ending December 31, 2025
($000)

MPSC Case No. U-21534
Initial Brief
Attachment B

Line No.	(a) Description	(b) Source		(c) Revenue Deficiency
				(Pre Tax Amts)
1	**Company's Filed Position**	Exhibit A-11 Sch A-1		**$ 456,434**
2				
3	**Adjustments to Revenue Deficiency:**			
4				
5			Rate Base Changes	
6	**Rate Base (1)**			
7	Capital Expenditure, Increase/(Decrease)	Attachment A page 2	(24,972)	(1,839)
8				
9	Working Capital, Increase/(Decrease)	Attachment A page 2	(15,499)	(1,142)
10				
11	**Operating Expenses**			
12	O&M, Increase/(Decrease)	Attachment A page 3		(5,110)
13	Depreciation Expense, Increase/(Decrease)	Attachment A page 3		(1,426)
14	Property Taxes, Increase/(Decrease)	Attachment A page 3		(677)
15				
16	**Rate of Return**			
17	- Short-term Debt Adjustment	Attachment A page 4		(177)
18				
19	**Total Adjustments to Company's Position**	Line 7 through Line 17		$ (10,371)
20				
21	**Company's Initial Brief Position**	Line 1 + Line 19		**$ 446,063**

(1) Rate Base Change multiplied by pre-tax return 7.37% (Attachment A page 4)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	))))))	Case No. U-21534

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on October 3, 2024, she served a copy of DTE Electric Company's Initial Brief in the above captioned matter, via electronic mail upon the persons listed on the attached service list.

Estella R. Branson

Digitally signed by Estella R. Branson
Date: 2024.10.03 15:41:23 -04'00'

ESTELLA R. BRANSON

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