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August 15, 2023

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

RE: In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority
MPSC Case No. U-21297

Dear Ms. Felice:

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

Very truly yours,

Jon P. Christinidis

JPC/erb
Attachments
cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21297

DTE ELECTRIC COMPANY'S
INITIAL BRIEF

Dated: August 15, 2023

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I. INTRODUCTION AND SUMMARY OF MAJOR ISSUES

This case began on February 10, 2023, when DTE Electric Company (DTE Electric or the Company) filed its Application and supporting direct testimony and exhibits, requesting a jurisdictional rate increase of \$622 million (\$619 million if the investment recovery mechanism (IRM) proposed by the Company is accepted), and other forms of regulatory relief. The projected revenue deficiency spans the projected test year of December 1, 2023 through November 30, 2024 (Vangilder, 5T 2591, 2601; Exhibit A-11, Schedule A1, line 10).

The Company's requested revenue deficiency is largely driven by the Company's continued distribution infrastructure investments to improve customer power reliability and generation investments to bring cleaner energy faster to the state. A substantial amount of DTE Electric's revenue deficiency in this case is comprised of 1) prudent capital investments already made during the historic test year and the early part of the bridge period in this case, i.e., 2021 and 2022, which has resulted in material regulatory lag for the Company; and 2) sales that are significantly lower than the level set for rates in the Company's last general rate case (Case No. U-20836). Together, these items alone account for over \$200 million of the Company's request in this case. Rising inflation has also impacted the Company's operation and maintenance (O&M) and debt costs. The Company's inflation factors of 3.6% for 2022, 3.2% for 2023, and 2.66% for January 1 through November 30, 2024 (see Exhibit A-13, Schedule C5.15, line 15) reflect a conservative and reasonable increase to O&M expense in light of the sustained impacts of inflation.

In addition to recovering historic capital and adjusting for lowered sales and higher inflation, the Company needs to continue moving forward with important investments in generation that support cleaner energy goals, as well as its distribution infrastructure to modernize equipment, improve worker and public safety, reduce the frequency and duration of power outages, and add

capacity to the grid to support a growing demand for electric vehicles (EVs) and distributed energy resources (DERs). Key to the successful execution of the Company's distribution system upgrades is the proposed Investment Recovery Mechanism (IRM). The IRM provides sustained funding for the implementation of well defined, systematic, long-duration projects while also requiring transparency and accountability to customers through annual reporting and a credit for any unspent funding.

DTE Electric initially requested that the Commission authorize an adjustment of rates to provide an additional \$619 million (Vangilder, 5T 2591, 2601; Exhibit A-11, Schedule A1, line 10) based on \$22.611 billion in rate base, which consisted of \$21.351 billion of net plant, \$1.260 billion of working capital (Vangilder, 5T 2592; Exhibit A-12, Schedule B1, column (d)), and adjusted Net Operating Income (NOI) of \$836.8 million in the projected test period (Uzenski, 5T 1497, 1513; Exhibit A-13, Schedule C1, line 17). After reviewing Staff's and other intervenors' positions and the full record in this case, DTE Electric supports and requests a projected revenue deficiency of \$583 million. (See Company's Attachments A and B included with this Brief).

The Company's requested relief also includes investments in technology and customer service, changes to certain tariffs, various accounting proposals, and several proposed pilot programs associated with EV charging, distribution non-wires alternatives (NWA's), and demand response (DR). (Crozier, 5T 2175-83). The Company is seeking a return on equity (ROE) of 10.25% (Villadsen, 5T 2954-55, 2995, 2999).

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. Therefore, DTE Electric requests that the Commission authorize an adjustment of rates to provide \$583 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 November 18, 2022 Order in Case No. U-20836.

On March 7, 2023, a pre-hearing conference was held and intervention was granted to the Michigan Attorney General (AG); the Association of Businesses Advocating Tariff Equity (ABATE); Bloom Energy Corp (Bloom); City of Ann Arbor (Ann Arbor); ChargePoint, Inc. (ChargePoint); Energy Michigan, Inc. (Energy Michigan or EM); EVgo Services, LLC (EVgo); Foundry Association of Michigan (FAM); International Transmission Company (ITC); Michigan Cable Telecommunications Association (MCTA); Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United (collectively MEIBC/IEI/Untied); Local 223, Utility Workers Union of America, AFL-CIO (UWUA or UWL 223); Great Lakes Renewable Energy Association (GLREA); Residential Customer Group (RCG); Wal-Mart, Inc. (Wal-Mart); the Kroger Company (Kroger); Gerdau MacSteel, Inc. (Gerdau); the Michigan Environmental Council (MEC), Natural Resource Defense Council (NRDC), the Sierra Club (SC) and the Citizens Utility Board of Michigan (CUB) (collectively MNESC); the Environmental Law & Policy Center, Ecology Center, Vote Solar, and Union of Concerned Scientists (collectively the Clean Energy Organizations or CEO); Michigan Municipal Association for Utility Issues (MI-MAUI); Soulardarity and We Want Green, Too (collectively the Detroit Area Advocacy Organizations or DAAO); and Zeco Systems, Inc. (Zeco) (IT 13).

Along with its Application, DTE Electric provided direct testimony and exhibits of 34 witnesses in support of its request for a rate increase and other regulatory relief:

- Maheen Asghar is a Principal Financial Analyst – Regulatory Economics (qualifications and direct testimony at 5T 3162-72);
- Robert A. Bellini is the Manager of Community Lighting (qualifications and direct testimony at 5T 2611-46);
- 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 5T 2061-73);
- Michael S. Cooper is DTE Energy Corporate Services LLC’s Director of Compensation, Benefits & Wellness (qualifications and direct testimony at 5T 1344-1403);
- Adella F. Crozier is the Director of Regulatory Affairs for DTE Energy Corporate Services LLC (qualifications and direct testimony at 5T 2169-2208);
- Jeffrey C. Davis is DTE Electric’s Expert - Nuclear Strategic Business Operations (qualifications and direct testimony at 5T 2432-98);
- Satvir Deol is the Director of Substation Operations Electric Marketing and Electrification (qualifications and direct testimony at 2T 185-232);
- Morgan Elliott-Andahazy is the Director, Project Management Organization (PMO) in Electric Distribution Operations (DO) (qualifications and direct testimony at 3T 495-561);
- Keegan O. Farrell is the Manager of Demand Response (DR) (qualifications and direct testimony at 5T 1283-1326);

- Neal T. Foley is the Director of Regulatory Affairs for DTE Energy Corporate Services LLC (qualifications and direct testimony at 2T 47-80);
- Evette G. Griffie is the Acting VP – Customer & Community Engagement (qualifications and direct testimony at 5T 2080-2102);¹
- Shannen M. Hartwick is the Director of Tree Trim (qualifications and direct testimony at 5T 2112-59);
- Michael J. Hatsios is the Director – Customer Service Operations (qualifications and direct testimony at 5T 1587-1778);
- Brian L. Hill is the Director - Distribution Operations Scheduling and Construction (qualifications and direct testimony at 5T 2726-97);
- Allan J. Kryscynski is the Manager – Distribution Operations Regulatory Strategy and Grid Modernization (qualifications and direct testimony at 3T 381-420);
- Robert J. Lee is DTE Energy’s Manager of Environmental Strategy (qualifications and direct testimony at 5T 1248);
- 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 5T 3258-77);
- Markus B. Leuker is DTE Electric’s Manager of Corporate Energy Forecasting (qualifications and direct testimony at 5T 2501-37);

¹ Witness Griffie adopted the originally-filed direct testimony of Tamara D. Johnson.

- Habeeb J. Maroun is a Regulatory Strategy Consultant in the Regulatory Requirements department of the Regulatory Affairs organization (qualifications and direct testimony at 5T 3124-53);
- Bryant F. Miller is the Manager – Distribution Operation Support (qualifications and direct testimony at 5T 2835-60);
- 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 5T 2540-50);
- Justin L. Morren is DTE Electric’s Plant Director - Energy Supply (qualifications and direct testimony at 5T 2245-2373);
- Thac K. Nguyen is the Manager - Energy Waste Reduction (EWR) (qualifications and direct testimony at 5T 1267-77);
- Kelsey Peterson is the Manager – Strategic Marketing, Planning & Development (qualifications and direct testimony at 4T 693-789);
- Mathew Pollack is a Senior Strategist – Regulatory Affairs (qualifications and direct testimony at 5T 3103-16);
- Diane K. Reterstorf is a Manager of Operational Technology for Distribution Operations (qualifications and direct testimony at 5T 2889-2932);²
- Joseph E. Robinson is DTE Electric’s Director - Central Engineering for Electric Distribution Operations (qualifications and direct testimony at 5T 2674-2701);

² Witness Reterstorf adopted the originally-filed direct testimony of Phillip L. Smith.

- Pankaj Sharma is the Director – Information Officer in the Revenue Requirements group of DTE Energy Corporate Services LLC’s Information Technology Services (ITS) organization (qualifications and direct testimony at 5T 1816-2044);
- Jason E. Sparks is the Director - Customer Services Organizations for DTE Energy Corporate Services LLC (qualifications and direct testimony at 5T 1441-61);
- Theresa M. Uzenski is the Manager of Regulatory Accounting DTE Electric and DTE Gas Company (DTE Gas) (qualifications and direct testimony at 5T 1466-1562);
- Kirk M. Vangilder is a Principal Financial Analyst for Revenue Requirements in DTE Energy’s Regulatory Affairs organization (qualifications and direct testimony at 5T 2581-2602);
- Dr. Bente Villadsen is a Principal of The Brattle Group, which is an economic, environmental and management consulting firm (qualifications and direct testimony at 5T 2949-3040);
- Aaron Willis is Manager - Regulatory Economics (qualifications and direct testimony at 5T 3175-3217); and
- Sherri L. Wisniewski is DTE Energy’s Director of Tax Operations (qualifications and direct testimony at 5T 2560-77).

On June 13, 2023, the Commission Staff and Intervenors filed their testimony and exhibits. Staff provided the testimony of William Ah Tou (7T 4331-35), Paul R. Ausum (7T 4336-39), Tayler Becker (7T 4341-52), Jonathan J. DeCooman (7T 4354-76), Roger A. Doherty (7T 4378-85), Jessica Duell (7T 4394-4403), Nicholas M. Evans (7T 4404-21), Allan D. Freeman (7T 4422-34), Jay S. Gerken (7T 4436-43), Justin J. Hecht (7T 4444-49), David W. Isakson (7T 4452-86), Lisa

M. Kindschy (7T 4504-19), Brittney Klocke (7T 4544-58), Kevin S. Krause (7T 4520-30), Cody S. Mathews (7T 4559-70), Theresa McMillan-Sepkoski (7T 4572-81), Robert F. Nichols II, CPA (7T 4583-90), Mark J. Pung (7T 4592-4603), Nicholas M. Revere (7T 4608-20), Danielle R. Rogers (7T 4644-68), Shannon Rueckert (7T 4670-83), Jing Shi, P.E. (7T 4690-98), Michelle L. Schreur (7T 4684-88), Joseph E. Ufolla (7T 4699-4721), and Joy H. Wang, Ph.D. (7T 4723-92).

ABATE provided the testimony of Brian C. Andrews (4T 1079-99), James R. Dauphinais (4T 1052-78), Christopher C. Walters (4T 1151-1224), and Jessica A. York (4T 1107-1150). The AG provided the testimony of Sebastian Coppola (6T 3621-3805) and Richard Bunch (6T 3597-3618), and with MNSC, also Paul J. Alvarez (6T 3311-58), and Dennis Stephens (6T 3359-3412). Ann Arbor provided the testimony of Mike Kennedy (4T 839-45), Skye Stewart (4T 846-53), and Dr. Mellissa Stults (4T 854-78). Bloom provided the testimony of Douglas B. Jester (6T 4113-38) and Peter Morse (6T 4099-4112). CEO provided the testimony of Margarita Parra Cobaleda (6T 3940-53), William D. Kenworthy (6T 3836-76), Dr. Guillermo Pereira (6T 3878-3915), and Boratha Tan (6T 3917-38). DAAO provided the testimony of Jackson Koeppel (6T 3956-4056). Energy Michigan provided the testimony of Alexander J. Zakem (6T 4077-96). EVgo provided the testimony of Lindsey Stegall (43T 990-1015). ITC provided the testimony of Kwafo Adarkwa (6T 4304-10) and Michael Fleck (6T 4311-13). Kroger provided the testimony of Justin Bieber (6T 4284-4302). MIEBC/IEI/United provided the testimony of Justin R. Barnes (6T 4232-51), Jason W. Hoyle (6T 4205-31), Kenneth D. Schisler (6T 4252-69), and Dr. Laura S. Sherman (6T 4142-89). MNSC provided the testimony of Tyler Comings (6T 3516-37), Douglas B. Jester (6T 3416-75), Chris Neme (6T 3476-3515), and Robert G. Ozar, P.E. (6T 3538-92). MI-MAUI provided the testimony of Richard Breuckman (4T 883-92), Richard Bunch (4T 893-940), James Krizon (4T952-

58), Joseph H. Spiegel (4T 959-82), and Coy P. Vaughn (4T 983-87). Wal-Mart provided the testimony of Lisa V. Perry (4T 1018-48).

On July 7, 2023, DTE Electric filed the rebuttal testimony and exhibits of witnesses Bellini (5T 2647-71), Burgdorf (5T 2074-77), Cooper (5T 1404-38), Crozier (5T 2209-41), Deol (2T 233-85), Elliott-Andahazy (3T 562-608), Farrell (5T 1327-39), Foley (2T 81-110), Griffie (5T 2103-10), Hartwick (5T 2160-65), Hatsios (5T 1779-1813), Hill (5T 2798-2832), Kryscynski (3T 421-47), Maroun (5T 3154-60), Miller (5T 2861-86), Milo (5T 2551-57), Morren (5T 2374-2429), Nguyen (5T 1278-81), Peterson (4T 790-811), Pollack (5T 3117-21), Reterstorf (5T 2933-46), Robinson (5T 2702-23), Sharma (5T 2045-58), Uzenski (5T 1563-83), Vangilder (5T 2603-2606), Villadsen (5T 3041-3101), and Willis (5T 3218-56).

Staff filed the rebuttal testimony of witnesses Doherty (7T 4386-91), Isakson (7T 4487-4502), Krause (7T 4531-42), Pung (7T 4604-4607), and Revere (7T 4621-42).

ABATE filed the rebuttal testimony of witness Andrews (4T 1100-1106). DAAO filed the rebuttal testimony of witness Koepfel (6T 4058-4074). Kroger filed the rebuttal testimony of witness Bieber (6T 4272-83). MEIBC/IEI/United filed the rebuttal testimony of witness Sherman (6T 4190-4204). MI-MAUI filed the rebuttal testimony of witness Bunch (4T 941-51).

On July 19-21, 2023, and July 24, 2023, the parties conducted cross-examination and bound in testimony and exhibits. Administrative Law Judge (ALJ) Sharon Feldman presided over the hearing. The public record consists of 4,795 pages of public transcript and continues with a confidential record (8T 4796-5042), and a multitude of exhibits.

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 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” standard³ or the “beyond a reasonable doubt” standard that is only applicable to criminal proceedings.⁴ The “preponderance of the evidence” standard is generally defined as follows:

³ *In re Moss*, 301 Mich App 76, 89-90; 836 NW2d 182 (2013).

⁴ *Thangavelu v Dep’t of Licensing & Regulation*, 149 Mich App 546, 554-555; 386 NW2d 584 (1986).

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:

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.⁵

The ability to take official notice is limited under applicable rules.⁶ 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 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

⁵ *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002).

⁶ 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).

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.⁷

⁷ 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).

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.⁸ It is also axiomatic that utility rates are overall rates,⁹ and that (with certain limited exceptions) "the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class."¹⁰

Proposals that are contrary to the controlling law of ratemaking are unlawful and merit no consideration. For example, MNSC witness Jester suggested that the Company's residential rate increase should be limited to the rate of inflation, or otherwise set at some arbitrary level based on affordability concerns (e.g., 6T 3447, 3474). The Company disagrees based on the law and well-established regulatory practice, and since Mr. Jester presented no evidence that the Company's projected expenditures associated with a specific project or activity are unreasonable or imprudent.

⁸ 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).

⁹ *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).

¹⁰ MCL 460.11(1).

Instead, he recommended a “top-down approach [that] will force consideration of tradeoffs rather than just evaluating each component of spending independently” (Jester, 6T 3446). Such tradeoffs would render the Company unable to make all of the investments necessary to improve reliability and resilience, which would harm customers (Crozier, 5T 2212-15). There is similarly no merit in Mr. Jester’s suggestion that the Commission “could order DTE Electric to file a residential affordability plan with its next rate case, with the objective of limiting residential rate increases to the rate of inflation” (6T 3452). In addition to the flaws outlined above, this would be an unnecessary duplication of the existing rate case process, where the costs underlying rates are already evaluated (Crozier, 5T 2215-16).

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.¹¹ 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

¹¹ 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).

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 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

DTE Electric’s projected test year is December 1, 2023 through November 30, 2024. The Company normalized and adjusted actual results from the historical test year ended December 31, 2021 to arrive at its filed projected revenue deficiency of approximately \$622 million (\$619 million if the IRM proposed by the Company is accepted). (Crozier, 5T 2183-84; Vangilder, 5T 2591, 2601; Exhibit A-11, Schedule A1, line 10). That amount is adjusted to \$583 million in this Brief (See Attachments A and B).

The only disagreement was by ABATE witness Dauphinais, who echoed his arguments from Case No. U-20836 against projected test years and that the Commission is not required to set rates using a projected test year (e.g., 4T 1065-66). The Company again disagrees, noting that this ALJ found that it is reasonable to use a projected test year that follows the expected date of a Commission order, and the Commission agreed, approving the Company’s projected test year (Case No. U-20836, Order dated November 18, 2022, p. 8), in accordance with consistent practice utilizing projected test years (Crozier, 5T 2216-17).

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 December 1, 2023 – November 30, 2024 test year in this case is plainly a “consecutive 12-month period.” In addition to Case No. U-20836, the 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).¹²

ABATE witness Dauphinais further asserted that “the use of a projected test year allows DTE to begin recovery of costs before those costs have been verified as being real and prudently incurred” (4T 1061). 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 Commission¹³ must apply that plain language, regardless of ABATE’s disagreement with how our Legislature wrote it.

¹² 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).

¹³ *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”).

The Company also verified that its projected costs are real as demonstrated by the robust record in this case. Contrary to Mr. Dauphinais' contention that certain expenditures were not "known and measurable changes" to the historical test year (4T 1063), most of the 2022 bridge period capital expenditures were known, measurable and provided in direct testimony, while the remainder of actual expenditures for 2022 and several months of 2023 were provided in responses to discovery. Mr. Dauphinais' further proposition that the Company's projections should be "precisely quantified" by the "specific quarter" in which they occur (4T 1067) should be rejected because this would be an unnecessary waste of resources that would add further complexity (both for the Company, as well as the Commission and all parties) to an already voluminous and complex process, with no apparent benefit. Instead, ABATE complains that the proceedings are complex, and counter-intuitively suggests that they should therefore be made more complex (Crozier, 5T 2217-19).

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 additional thousands of responses to audit and discovery requests) verifying the Company's projected costs.

V. RATE BASE

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 \$22.611 billion, which consisted of \$21.351 billion of net plant, and \$1.260 billion of working capital (Vangilder, 5T 2592; Exhibit A-12, Schedule B1, column (d)).

There are small adjustments to the 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 \$22.344 billion, which consists of \$21.094 billion of net plant and \$1.251 billion of working capital.

A. Working Capital

As indicated above, DTE Electric supported a projected working capital amount of \$1.260 billion (See also, Uzenski, 5T 1535; Exhibit A-12, Schedule B4).

AG witness Coppola proposed removing \$38.9 million from working capital for a special investment fund with Energy Insurance Services (EIS) because the gains related to changes in market value are excluded from rates (6T 3761-62). The AG's proposal should be rejected because the Company's investment for funding insurance supports utility operations and is properly included in rate base. The investment fund is used to record DTE's interest in EIS, which is a Segregated Captive Cell Insurance (captive insurance) company, meaning that assets are held for insurance purposes that are for DTE only. The asset is marked to market quarterly, which results in the recognition of gains and losses. The gains and losses on the investment fund have been excluded from rates because they are related to changes in the market value of the fund and cannot be forecasted (Exhibit A-36, Schedule AA3 shows gains and losses over the last five years). Instead of removing the asset from rate base, the Company proposes to include a projection for gains and losses on the investment in future rate cases. This would be consistent with how gains and losses on DTE Gas' Grantor Trust fund are treated for ratemaking (Uzenski, 5T 1565, 1574-75).

The Company agrees with Staff's proposal to project working capital on a thirteen-month average basis. The Company accepts the \$1.7 million reduction to working capital. Therefore, AG witness Coppola's proposed \$20 million reduction to working capital related to fuel inventory based

on using a thirteen-month average instead of the simple average that the Company used (Coppola, 6T 3762-63) should not be approved because it would be duplicative (Uzenski, 5T 1565, 1575).

Staff proposed a reduction in working capital for non-utility accounts receivable balances of \$7.3 million (Hecht, 7T4447). The Company accepts this adjustment.

AG witness Coppola proposed to remove the \$5.6 million regulatory asset for deferred incentive compensation from working capital, arguing that it is premature to create a regulatory asset (6T 3765). The Company disagrees because accrual accounting allows the Company to record a regulatory asset when recovery is probable. Although the Company is not requesting recovery of the deferred costs in amortization expense in this case, it is appropriate to accrue the regulatory asset on the balance sheet because the Commission approved such treatment in Case No. U-20836 (Uzenski, 5T 1565, 1575-76).

Based on the acceptance of Staff's reduction to working capital of \$7.3 million for non-utility accounts receivable and \$1.7 million for the thirteen-month average, DTE Electric supports a \$1.251 billion working capital balance.

B. Capital Expenditures

DTE Electric has made or will make approximately \$7.6 billion of capital expenditures from the end of the historical test year to the end of the projected test year (January 1, 2022 through November 30, 2024) (Exhibit A-12, Schedule B5, line 13, columns (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 Morren explained and supported total Energy Supply¹⁴ capital expenditures of \$524.6 million for 2021, \$451.9 million for 2022, \$958.6 million for the 23 months ending November 30, 2023, and \$520.5 million for the projected test year (Exhibit A-12, Schedule B5.1, page 1, line 13, columns (b), (c), (e) and (f)). Energy Supply has a rigorous capital spending and approval process that is designed to identify the optimal allocation of capital resources to meet safety and environmental regulations, while maintaining overall reliability performance and reducing costs (Morren, 5T 2260, 2373).

Mr. Morren provided an overview of expenditures for routine and non-routine projects as reflected on Exhibit A-12, Schedule B5.1, page 1 (Morren, 5T 2266-69), and described the major non-routine capital projects (5T 2269-98; Exhibit A-12, Schedule B5.1, page 2), and the major routine capital projects (5T 2298-2340, 2349-60; Exhibit A-12, Schedule B5.1, pages 3-7). Mr. Lee further explained and supported the Company's actions to comply with Coal Combustion Residuals (CCR) Rule requirements at the Company's CCR sites (St. Clair Bottom Ash Basins, Belle River Bottom Ash Basins and Diversion Basin, Monroe Fly Ash Basin, River Rouge Bottom Ash Basin, Monroe Bottom Ash Basin, and Sibley Quarry Landfill). (Lee, 5T 1261-65).

MNSC witness Comings proposed a \$20.1 million disallowance (\$18.8 million in 2023, and \$1.3 million in 2024) to Monroe capital expenditures, claiming only that seven projects lack supporting documentation, and two projects lack supporting documentation for an updated 2023 spending forecast (6T 3536-37). This claim is incorrect and apparently based on a

¹⁴ In July 2021, the Company restructured some of its business units and combined Renewables Operations with the Fossil Generation business unit into a new integrated business unit called Energy Supply (Morren, 5T 2248).

misunderstanding.¹⁵ Some workpapers associated with capital projects, although uploaded, had not been “checked into” the Company SharePoint portal as of February 10, 2023. Those files were subsequently “checked in” and made visible to all parties on May 18, 2023, so all parties had access to the information weeks before intervenor testimony was filed. The workpapers are also in the record as Exhibit A-35, Schedule Z1. Table 1 (at Morren, 5T 2380) provides the supporting document titles in the workpapers, and identifies where the projects are discussed in Mr. Morren’s direct testimony for the nine projects at issue. The projects listed in Table 1 are required to maintain critical plant equipment and environmentally-compliant operations. Most of the projects are related to the Monroe Unit 1 periodic outage, which was completed in the spring of 2023, and the unit returned to service with the projects in service. At bottom, there was an administrative error and misunderstanding concerning limited additional project information (among thousands of pages of such information), the projects have always been supported in direct testimony and exhibits, and the projects (which involve ordinary maintenance activity and have been completed) should not be disallowed due solely to a technical issue in the timing of uploaded additional support documentation (Morren, 5T 2379-83).¹⁶

The Company further explained that projected capital expenditures could be significantly reduced based on Monroe Units 3 and 4 retiring in 2028 as the Company proposed in its Integrated

¹⁵ ABATE witness York initially proposed a similar disallowance but filed revised direct testimony removing the proposal (and the Company withdrew its corresponding rebuttal testimony) after the parties addressed the misunderstanding.

¹⁶ Mr. Comings also stated that many projects lacked any supporting internal rate of return (IRR) analysis documentation (6T 3534). He did not directly assert that this was a problem, but the comment suggests that he overlooked a discovery response (Exhibit A-35, Schedule Z2), which explains that IRR analyses are generally not performed for safety, environmental, and regulatory compliance projects, as well as for projects that are considered capitalized maintenance (pumps, motors, valves, and other equipment that is routinely replaced or overhauled to return the equipment to operational status). This is a proper application of the Company’s operational and engineering judgment in providing reasonable and prudent utility service (Morren, 5T 2382).

Resource Plan (IRP) case.¹⁷ This will allow several capital projects to be avoided or scaled back, lowering the required capital expenditures. The avoided or scaled back capital expenditures include over \$42 million of routine capital expenditures (Morren, 5T 2341-48 and Exhibit MEC-13 page 5), \$17 million of non-routine capital expenditures related to the Monroe Bottom Ash Conversion (ELG) project (Exhibit MEC-13, page 1), and \$21 million of non-routine capital expenditures related to the Monroe Flue Gas Desulfurization (FGD) wastewater project (further discussed in the next subsection).

Staff proposed a \$39.9 million adjustment (\$19,231,423 for the 11 months ending November 30, 2023; \$20,628,303 for the projected test year) based on the unsupported assumption that Monroe units 3 and 4 are responsible for half of the common costs for the Monroe Bottom Ash (ELG) project (Kindschy, 7T 4512). This assumption is incorrect because common system costs (such as the common feed from the high-pressure general service water system and the sump system) will remain regardless of whether two units or four units are operational. Common costs also include engineering costs, which are not reduced by half if Monroe Units 3 and 4 retire in 2028. The Company identified \$17.2 million of potential avoidable costs specific to Monroe Units 3 and 4 if the Company retires Units 3 and 4 in 2028 (Morren, 5T 2418-19; Exhibit A-35, Schedule Z13).

The Company identified \$6.5 million of avoidable costs for the Monroe Unit 3 Waterwall Tubes project (Morren, 5T 2343-44). Staff “agrees . . . and removes an additional \$2,250,000 for this project that equates to half of the 2024 costs . . .” (Kindschy, 7T 4514). This additional amount is incorrect. It is based on an unfounded assumption that the cost of a waterwall replacement project is directly proportional to the square footage being replaced. There are many parts of a waterwall project that are not reduced by half simply because the square footage being replaced is reduced by

¹⁷ On July 26, 2023 Order, the Commission issued an Order Approving Settlement Agreement in Case No. U-21193.

half (e.g., erecting staging areas, installing temporary power and lights, and other examples listed in Mr. Morren’s rebuttal testimony). These non-variable costs were considered by the Company in determining the \$6.5 million of avoidable costs. This is the correct amount that should be used (Morren, 5T 2419).

The Monroe Unit 3 DCS & Control Room project replaces DCS hardware that was last replaced over a decade ago and software that dates back to the 1980s and is no longer supported by the vendor. The Company identified \$750,000 of avoidable costs (Morren, 5T 2343-44). Staff proposed a full disallowance (\$1,176,000 for the 11 months ending November 30, 2023; \$3,858,314 for the projected test year), reasoning that “Staff confirmed through discovery that all of the expenditures for this project in 2023 and 2024 are now avoidable with a 2028 retirement date for Monroe Units 3 and 4” (Kindschy, 7T 4513). AG witness Coppola proposed a full (\$3.823 million) project disallowance for 2024, using similar reasoning (6T 3713). The Company disagrees, noting its discovery response explaining: “The current Monroe Unit 3 DCS could potentially operate through 2028. However, the DCS may require upgrades that the Company is reviewing. Additional analysis has to be performed before determining the extent of scope that could be avoidable” (Exhibit A-35, Schedule Z14). Therefore, portions of this project may still require completion in 2024, which can be reviewed in a future rate case (Morren, 5T 2419-20; Exhibit A-35, Schedule Z14 further reflecting how the Company has been keeping the equipment running to this point).

The Monroe Bottom Ash Conversion (ELG) project is to install an ELG-compliant bottom ash transport system that must be completed at Monroe by the December 31, 2025 deadline (Morren, 5T 2272-74; Exhibit A-12, Schedule B5.1, page 2, line 5). In Case No. U-20836, the Commission previously agreed with this ALJ’s recommended disallowance of recovery beyond 2021 expenditures based on a lack of corporate approval (November 18, 2022 Order in Case No.

U-20836, p 16-18). Subsequently, the Company's Board of Directors Finance Committee approved the funding and execution of this project in December 2022 so that objection has been fully addressed (Morren, 5T 2272).

ABATE witness York proposed disallowances of \$4.3 million for 2022, \$28.9 million for the 11 months ending November 30, 2023, and \$41.3 million for the projected test year, reasoning that there is uncertainty because the Company's direct testimony did not indicate if an RFP has been issued, or identify what material it will continue procuring in 2023 (4T 1124-25). The Company disagrees because it remains on track to release the RFP this fall, and the Company's direct testimony identified the systems being installed. The major components that are being procured include the submerged grind conveyors and enclosed belt conveyor systems. Witness York's suggestion to disallow 2022 expenditures also disregards that the Company provided actual monthly capital expenditures for 2022 in discovery (Exhibit A-35, Schedule Z4) showing that total actual annual capital expenditures were \$4.2 million, so there is no uncertainty on that score. Therefore, ABATE's proposed disallowance should be rejected (Morren, 5T 2421-2422).

AG witness Coppola proposed a complete (\$48.7 million) disallowance for five change orders relating to the construction of the Blue Water Energy Center (BWEC), asserting that they show increased project costs based on Company decisions that should have been handled differently (6T 3692-99). The Company disagrees because change orders are not written to increase project costs, but instead to authorize/assign work. Change orders on construction projects, especially on a project of this magnitude, are often vital and necessary to complete the work properly. In addition, the Commission has already approved BWEC construction costs. See generally, April 27, 2018 Order in Case No. U-18419, p 126 (authorizing recovery of up to \$951.8 million through rates); November 18, 2022 Order in Case No. U-20836, p 40-41 (approving recovery except for \$8.1

million of contingency).¹⁸ Mr. Coppola therefore suggests disallowances for capital costs already approved for inclusion in rate base. Moreover, the change orders largely relate to the Company managing the BWEC through the COVID-19 pandemic, so the suggested disallowances ignore the extraordinary context in which the work was successfully accomplished (Morren, 5T 2384-85).

Mr. Morren also presented detailed testimony supporting every change order. In general summary: (1) The first change order compensated Kiewit (the major engineering, procurement, and construction (EPC) contractor) for extended staff retention, incremental heavy equipment rental, and ongoing equipment care and maintenance during the six-week COVID-19 work suspension at Kiewit's cost without a profit component (5T 2385-86); (2) The second change order concerned necessary costs to increase staffing to make up for lost time, as well as offset productivity losses due to COVID-19 protocols and weather, in order to meet the BWEC's commercial operating date, and support the planned retirement of the St. Clair and Trenton Channel power plants (5T 2386-87; Exhibit A-35, Schedule Z4); (3) The third change order arose because the location of the required new ITC substation was not known when the original contract with Kiewit was developed, and represents the adjustment for building a longer transmission line from the BWEC to the new substation than was originally estimated (5T 2388); (4) The fourth change order concerns construction of a warehouse that is necessary to store parts, and arose because the space requirements were not fully known when the BWEC contract was executed with Kiewit, and the Company did not want to build more warehouse space than necessary (5T 2388-89); and (5) The fifth change order related to the installation of a non-odorized natural gas monitoring and alarm system. It arose because the original contract assumed that the plant's natural gas supply would be

¹⁸ Staff double-counted a contingency adjustment in this case, with recommended disallowances of \$8.1 million (DeCooman, 7T 4362) and \$6.8 million (Rogers, 7T 4666), which combine to \$14.9 million. The disallowances are related to the same thing, and should not exceed the \$8.1 million of contingency that the Commission did not include for recovery in Case No. U-20836 (Morren, 5T 2423-24).

odorized, but the Company then saw an opportunity to save costs by using non-odorized natural gas, which required the monitoring and alarm system for safety reasons. The decision to use non-odorized gas with gas detection provided the most value to customers and saved annual expense for mercaptan. Therefore, the change orders were reasonable and prudent, and Mr. Coppola's recommendation should be rejected (5T 2389).

ABATE witness York proposed disallowances of \$8.8 million for site security projects, and \$1.7 million for North American Reliability Corporation (NERC) compliance projects (reflected at Exhibit A-12, Schedule B5.1, page 2, lines 8-18), acknowledging that the Company supported its requests with testimony and PMP forms provided in workpapers, and offering no reason for any disallowance other than a reference (without discussion or analysis) to the Commission disallowing costs in Case No. U-20836 (4T 1126-27). Witness York's proposal should be rejected because the Company supported its requests here with testimony and PMP forms provided in workpapers. The record adequately supports the projects and reflects that they have Company approvals (Morren, 5T 2275-77, 2391).

The Company requests funding for three black start projects that support the NERC black start plan (Morren, 5T 2289-90; Exhibit A-12, Schedule B5.1, page 2, lines 47-49). Staff proposed a combined \$6.5 million reduction in the Company's requested funding for three black start projects, noting that the Commission did not approve funding in Case No. U-20836, but "[s]ince that time significant expenditures have been made for these projects. Therefore, Staff finds it reasonable to approve most of these capital expenditures, while still making modest adjustments to reflect the most up-to-date projections and account for uncertainty in future spend" (DeCooman, 7T 4366). The Company appreciates Staff only making what they consider to be "modest adjustments," but disagrees with the underlying assumption that because a project was underspent

(actual spending was less than forecast) in the past, that future projections should be reduced (Morren, 5T 2392).

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

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

AG witness Coppola and ABATE witness York proposed disallowances relating to the River Rouge, St. Clair, and Trenton Channel (frequently described as "Tier 2" plants) decommissioning projects (Exhibit A-12, Schedule B5.1, page 2, lines 32, 35, and 37). Mr. Coppola proposed a \$62.0 million reduction in the St. Clair project, based on the Company deciding to split the project into two projects subsequent to filing this case, with the first project included in this proceeding, and the second project postponed for consideration in the next rate case (6T 3690-91).

The Company generally agrees, but the correct calculation of the reduction should be \$56.6 million (Morren, 5T 2402).

ABATE witness York proposed a full (\$236.6 million) disallowance for all three Tier 2 power plant decommissioning projects. Regarding St. Clair (originally \$96.731 million), she indicated various concerns, including that the Company had not received all necessary internal approvals (4T 1128). As indicated above, the Company split the project in two, and only seeks recovery for the first project in the instant case. The first project has full internal approval, and the Company provided the related project approval forms in discovery and those approval forms were admitted as an exhibit (Exhibit A-35, Schedule Z7). Witness York also indicated a concern about contractual bids and vendor information concerning St. Clair, but this is irrelevant here because the selection of the demolition contractor will be part of the second project. Witness York's proposed disallowance also includes 2022 capital expenditures. The Company provided the actual amounts incurred in 2022 (\$9.9 million) so there is no uncertainty about this cost (Exhibit A-35, Schedule Z5). Witness York also did not offer any specific criticism regarding reasonableness or prudence. For all of these reasons, witness York's proposed disallowance (to the extent that it exceeds \$56.6 million as the correct reduction based on the project split as discussed above) should be rejected (Morren, 5T 2403-2404).

Regarding the River Rouge (\$55.072 million) and Trenton Channel (\$84.842 million) decommissioning projects, witness York indicated uncertainties including whether the Company received all necessary internal approvals (4T 11130-32). However, ABATE overlooked information. The Company provided the Capital Appropriation Request Forms (CARFs) that approved the complete River Rouge and Trenton Channel decommissioning projects in Mr. Morren's workpapers which were admitted as an exhibit (Exhibit A-35, Schedule Z8). Regarding

witness York's indicated concern about RFP information, Mr. Morren's direct testimony indicated that the Company issued a demolition RFP, evaluated the bids, and selected a vendor in 2022 for the River Rouge project (5T 2283), and that the Company completed a demolition RFP and chose a vendor for the Trenton Channel project (5T 2286). Witness York's indicated concern that project costs are higher in this case than in Case No. U-20836 neglects that this case concerns a different time period with projections beyond the prior case's timeframe. Witness York's proposed disallowances also improperly includes 2022 capital expenditures. The Company provided the *actual* amounts incurred in 2022 (\$13.0 million for River Rouge; \$9.7 million for Trenton Channel) so there is no uncertainty regarding these expenditures (See Exhibit A-35, Schedule Z5). Witness York also did not offer any specific criticism regarding reasonableness or prudence. Therefore, the proposed disallowances should be rejected (Morren, 5T 2405-2407).

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

To the contrary, the Company explained in discovery (included in Exhibit A-35, Schedule Z9) that the FGD systems were designed with back-up power to be provided by adjacent unit system service transformers in the event of a system service transformer or auxiliary transformer failure. The existing design is sufficient if adjacent generation units are available, but in the event of a site blackout in which all generating assets are unavailable, that system would not allow for stabilization of critical FGD equipment, resulting in severe damage (examples included in Exhibit A-35, Schedule Z9). This actually happened, requiring an extended outage to manually remove limestone

slurry that had hardened. Mr. Coppola's suggestion that there could be less costly options "including temporarily obtaining power from the grid" (6T 3710) similarly reflects a lack of appreciation of the need to prevent system damage in the event of a site blackout, and that a site blackout might be part of a larger grid blackout. Mr. Coppola also suggested that the project is wasteful due to the early retirement of Monroe units indicated in the Company's IRP (6T 3710). The Company disagrees because the backup generators will provide valuable protection from extensive FGD equipment damage through the remaining operational years. Therefore, the generators, which are already installed and expected to be operational by the end of this year, should be approved (Morren, 5T 2408-10).

The Monroe Wastewater Discharge System requires enhancements to process wastewater flows more efficiently, and sustain compliance with environmental permit requirements (Morren, 5T 2327; Exhibit A-12, Schedule B5.1, page 6, line 161). Mr. Coppola recommended disallowances totaling \$7,007,000, suggesting that there is "uncertainty and conflicting information," because a discovery response "seems to refer to effectiveness and efficiencies and not to environmental risks" (6T 3711-12). To the contrary, the discovery response (included in Exhibit A-35, Schedule Z10) makes no mention of any efficiency improvement. Mr. Coppola also suggested that it is uncertain whether the upgrade is necessary because the Company's IRP contemplates that Monroe Units 3 and 4 will retire in 2028 (6T 3712). The Company disagrees because Monroe Units 1 and 2 would continue to use this common coal pile runoff system into the 2030s. Therefore, the Company's requested recovery should be approved (Morren, 5T 2410-11).

The Blue Water Energy Center (BWEC) Conference Room Building project involves \$5 million to construct a new building at the BWEC site to provide a safe location away from plant operations to accommodate large work crews for outages, site-wide meetings, and visitors (Morren,

5T 2359-60; Exhibit A-12, Schedule B5.1, page 7, line 234). AG witness Coppola proposed a full disallowance, reasoning that “the Company provided only minimal information that makes it impossible to assess the need for the new building” (6T 3717). The Company disagrees because it provided discovery responses (included in Exhibit A-35, Schedule Z11) that show a good faith effort to provide as much detail as possible, and Mr. Coppola did not indicate how additional (often security sensitive) information would be relevant to determine whether the project is justified (Morren, 5T 2412-13).

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

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. Further details are presented below in the context of specific topics.

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

Company witnesses Morren 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. (Lee, 5T 1253-54; Morren, 5T 2262-63).

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, 5T 1254-55).

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, 5T 1255).

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. 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 (Lee, 5T 1255-57; Morren, 5T 2263).

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 \$55 million of new ELG-compliant bottom ash technology by the end of 2025 (Morren, 5T 2263).¹⁹

The Company is proceeding with FATW, BATW, and FGD wastewater projects at the Monroe Power Plant to meet the fast-approaching ELG compliance deadlines. In summary, the Company is currently implementing projects for FATW ELG compliance according to the 2015 Rule, which will allow the plant to continue operating beyond 2023.²⁰ The Company will achieve BATW wastewater ELG compliance by the end of 2025.²¹ The Company has chosen a VIP technology to achieve FGD wastewater compliance by December 31, 2028. Monroe Power Plant Units 3 and 4 are expected to retire by the end of 2028 under the Company's most recent IRP.²² These retirements will eliminate the units' production of FGD wastewater, and thereby eliminate the need (including a \$21 million expense) to install FGD wastewater treatment systems on those

¹⁹ 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, 5T 1258).

²⁰ The FATW portion of the ELG Rule requires companies to cease water discharges related to the transport of fly ash by the end of 2023. The project to install piping, silos, and other infrastructure for the dry transport of fly ash from Monroe Power Plant boilers to a storage area was approved by the Company's Board of Directors in 2020, is fully underway, and will meet the required compliance date (Morren, 5T 2264).

²¹ 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's Board of Directors Finance Committee in 2022, is fully underway, and will meet the required compliance date (Morren, 5T 2264).

²² On July 26, 2023, the Commission issued an Order Approving Settlement Agreement in Case No. U-21193.

units. Monroe Units 1 and 2 will necessarily meet the FGD wastewater revised stringent guidelines by utilizing an evaporator dryer system to eliminate FGD liquid discharges to the environment (Lee, 5T 1258-59; Morren, 5T 2264-65, 2271-74).

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, 5T 1260). The law has not changed, and one can only speculate that it might change at some time in the future.²³ 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, 5T 1260).

The Belle River Fuel Conversion project is to convert Belle River's fuel source from coal to natural gas, consistent with the commitment to cease coal-fired operations indicated above, and the Company's most recent IRP (Morren, 5T 2269-70; Exhibit A-12, Schedule B5.1, page 2, line 2). ABATE witness York proposed a full (\$38.763 million) disallowance. She acknowledged ABATE's support for the project, and the Company's testimony regarding completed engineering studies to confirm that the conversion is feasible, issuing an RFP to select an engineering, procurement, and construction (EPC) contractor, and that major design phases will be materially completed and long lead material will be procured in 2023; however, she asserted that "it is uncertain whether DTE will actually select an EPC in 2023, and whether the EPC will meet DTE's

²³ 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).

intended timelines” (York, 4T 1123). The indicated concern is unwarranted because in April the Company responded in discovery that “EPC bids for the Belle River natural gas conversion project are due back to the Company in mid-May 2023”. The Company did receive EPC bids in May. (Exhibit A-35, Schedule Z12; 5T 2414-16).

Witness York further suggested that recovery should be disallowed because the actual conversions will not occur until 2025 and 2026 (4T 1123). This suggestion neglects that expenditures in the bridge period and projected test year are for contracted work necessary to achieve successful and timely fuel conversion (Morren, 5T 2414). ABATE’s suggestion that the Company should be disallowed rate recovery for projects with in-service dates outside the test year is also inconsistent with legal and regulatory practice. Project costs can be included in rate base if they are deemed reasonable and prudent regardless of whether they will be in service in the projected test year.²⁴ Under well-established accounting practice, and in compliance with the Commission’s May 10, 1976 Order in Case No. U-4771, utilities may include construction work in progress (CWIP) in rate base because the revenue requirement is generally offset by an Allowance for Funds Used During Construction (AFUDC). AFUDC is applied to projects greater than \$50,000 and lasting more than six months, with an exception for environmental and other specifically ordered projects. (Uzenski, 5T 1541, 1572-73).²⁵

²⁴ 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).

²⁵ If the Commission were to accept ABATE’s proposition, then then the impact could be material, and the Commission should order a corresponding adjustment (reduction) in pre-tax AFUDC in projected net operating income to offset the removal of projects from approved rate base (Uzenski, 5T 1573).

ii. Slocum BESS Pilot

The Slocum Battery Pilot (Exhibit A-12, Schedule B5.1, page 2, line 51) is a pilot to replace the diesel-fueled peakers at the Company's Slocum peaker site located in the City of Trenton with a 14MW / 56 MWhr lithium-ion (Li-ion) Battery Energy Storage System (BESS) that will store excess energy that is generated on the grid during off-peak hours. This energy will then be available for dispatch during higher-priced peak hours (Morren, 5T 2291). The Company presented this pilot in its previous rate case, where the Commission ordered partial recovery and noted its expectation for a further discussion in this case, relevantly stating:

[T]he Commission finds the Staff's confidence in the reasonableness of the project persuasive and adopts the Staff's partial disallowance for the bridge period and full disallowance for the test year to address the company's lack of support for changing and fluid project costs [citing record and noting that the proper disallowance amount was \$28.187 million]. The Commission expects the company to present actual plans for the remainder of the project in its next rate case. [November 18, 2022 Order in Case No. U-20836, p 51.]

Accordingly, Mr. Morren sponsored Exhibit A-12, Schedule B5.1.1 (an update of Exhibit A-12, Schedule B5.1.3 from Case No. U-20836), which details the need, goals, design, expected pilot costs, stakeholder engagement process, and how the project is in the best interest of the public (Morren, 5T 2293). Mr. Morren also provided additional testimony on the substantial progress that the Company made on the project in 2022, and the Company's specific plans for 2023 and 2024, with BESS commercial operations starting in November 2024 (Morren, 5T 2291-93).

AG witness Coppola proposed a total (\$34,643,000) disallowance, essentially repeating his arguments from Case No. U-20836 that the Company did not make a convincing case that the project can create sufficient value for customers relative to the investment required (6T 3706-3707). The Company disagrees because the Attorney General's position disregards the results of Case No. U-20836, as well as the additional information in the instant case, as indicated above. Mr. Coppola also suggested that the BESS' 4 hours of energy capacity would not satisfy "the Company's own

Time of Day rate design schedules [which] assume a five-hour period, from 2 pm to 7 pm” (6T 3704). This suggestion is incorrect because the Company’s Time of Day rate design schedule uses a four hour on-peak window from 3 PM to 7 PM. Therefore, Mr. Coppola’s proposal should be rejected (Morren, 5T 2396-98).

Staff continues to support the pilot, and generally found that the Company’s additional information satisfies the Commission’s directives from Case No. U-20836 (DeCooman, 7T 4368-69), but “recommends partial disallowances of \$932,000 and \$975,000 in projected capital expenditures in the 2022 and 2023 bridge period, respectively, and a partial disallowance of \$1,633,000 in projected capital expenditures in the 2024 test year” (DeCooman, 7T 4370). The Company appreciates Staff’s continuing general support, but disagrees with Staff’s calculation of a partial disallowance by applying the percentage of expenditures underspent (rate case forecast vs. actual) on the project in 2022 to the Company’s projections. As discussed previously, it is inappropriate to assume that because a project is underspent in a year, the projection for future years should be adjusted downward by the percentage underspent in the prior year. The methodology is also unjustly asymmetrical, since Staff does not apply an upward adjustment where actual spending is greater than the rate case forecast (as reflected, for example, in Exhibit A-35, Schedule Z5, for the Monroe Dry Fly Ash Conversion (ELG) project). Therefore, Staff’s proposed disallowances based on this methodology should not be adopted (Morren, 5T 2398-99).

iii. Trenton Channel BESS Project

This request (2025/2026 Battery, at Exhibit A-12, Schedule B5.1, page 2, line 52) reflects expenditures needed for engineering and long lead material procurement to support 46 MW of build in 2025, and 60 MW of build in 2026, at the recently-retired Tier 2 Trenton Channel Power Plant, consistent with the Company’s proposed course of action (PCA) in its most recent IRP, Case No.

U-21193 (Morren, 5T 2295). The project was later expanded and accelerated to be a 220 MW lithium-ion BESS with a target COD in 2025, as reflected in Case No. U-21193.

AG witness Coppola recommended a full (\$81.2 million) disallowance, reasoning that the project was premature, largely because the Commission had not yet rendered a decision in Case No. U-21193. (6T 3708). The Company disagrees because the project in the instant case is consistent with the Company's IRP (Morren, 5T 2400) and whether a decision has been made does not negate that fact.²⁶

ABATE witness York similarly proposed a full disallowance, essentially reasoning that the Company did not support its request with enough detail. (4T 1132). In addition to the discussion above, the Company disagrees because it supported the project, and it had sufficient project and timeline detail to bid the project earlier this year (as reflected in discovery responses, which are consolidated as Exhibit A-35, Schedule Z6). The Company further notes that the project will allow the Company to take advantage of economies of scale during material procurement and site construction. This is the preferred location for the near-term battery deployment due to the large amount of land available, and the ability to repurpose the Trenton Channel Unit 9's transmission interconnection rights using MISO's generating facility replacement process. The Company has three years from the time Trenton Channel Unit 9 retired in 2022 to re-use interconnection rights. The ability to reuse an existing generator interconnection has several benefits including a significant time reduction as compared to a new generator interconnection, and avoiding the need to pay for land acquisition, engineering study costs, electrical tie-in infrastructure, and network upgrades (transmission projects). Therefore, full cost recovery should be approved (Morren, 5T 2295-97, 2400-2401).

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

2. Fuel Supply and Midwest Energy Resources Company

Mr. Milo supported DTE Electric's Fuel Supply and Midwest Energy Resources Company (MERC) capital expenditures for 2021 through the projected period ending November 30, 2024. The capital expenditures of \$2.8 million for 2021, \$4.6 million for January 2022 through November 2023, and \$2.5 million for the projected test year (as shown on Exhibit A-12, Schedule B5.2), relate to improving safety, meeting environmental requirements, reliable operations, and/or replacement of end-of-life equipment. The capital expenditures are reasonable and prudent, and necessary to extend and/or improve Fuel Supply operations and MERC's coal transshipment capabilities (Milo, 5T 2544, 2546-49; Exhibit A-12, Schedule B5.2, columns (b), (e) and (f)). Therefore, the expenditures should be approved.

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

MNSC's proposal to disallow MERC capital expenditures (\$1.5 million in the projected test year) should be rejected because MERC is a critical transshipment source of coal for Belle River, which is designed to primarily receive coal deliveries by vessel. MERC is also crucial in supplying a significant portion of the western coal used at Monroe, so MERC's continued safe operation is indispensable in providing reliable electricity to customers through the projected test year and beyond. In addition to Mr. Jester failing to suggest any alternative, Mr. Milo explained that no other transshipment facilities could perform the required services at the cost MERC provides, and providing for deliveries by rail to Belle River would require significant and costly

modifications to the coal unloading system, which would be operational for only a short period of time until the conversion.²⁷ Moreover, MERC continues to provide a reduction in DTE Electric's (and its customers') PSCR expense through third-party revenues (Milo, 5T 2553-54, 2556-57).

MNSC's proposal to disallow capital expenditures on railcars (\$1.0 million in the projected test year) should similarly be rejected because DTE Electric maintains the railcar fleet not only to control coal deliveries to its power plants, but also to optimize the cost savings associated with rail transportation by using private equipment. It is critical to rebuild railcar trucks on the 1997-1999 vintage cars to extend the truck's useful life and operability consistent with expected operations, so that these railcars remain in safe and reliable operating condition to support DTE Electric's coal transportation needs through the projected test year and beyond (Milo, 5T 2548-49, 2554-57).

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

²⁷ Mr. Jester also inaccurately asserted that MERC's "[c]apital expenditures per ton are increasing from \$0.18 in 2022 to \$0.49 in 2024" (6T 3461). He incorrectly computed 2024 capital costs as \$2,643,000 based on the 23-month bridge period. Using \$1.5 million from the projected test year would result in \$0.28 per ton. The whole exercise of calculating cost per ton is also unsound because capital expenditures for replacing end-of-life equipment, operating the facility in a safe and reliable manner, and maintaining environmental compliance do not change based on the volume of coal transshipped. Moreover, Mr. Jester's own Exhibit MEC-6 also reflects that MERC's annual capital expenditures have decreased since 2013, demonstrating that MERC has taken prudent steps to reduce its capital costs (Milo, 5T 2555-56).

3. Nuclear - Fermi 2

Mr. Davis described the operation of the Fermi 2 Nuclear Power Plant (Fermi 2) and supported Fermi 2's 2021 actual, as well as projected, capital expenditures through November 30, 2024. The Nuclear Regulatory Commission (NRC) has licensed Fermi 2 to operate through 2045. The capital expenditures (and O&M expenses discussed elsewhere) that Mr. Davis discussed throughout his testimony reflect reasonable and prudent measures to ensure the safe and reliable extended operation of Fermi 2 (Davis, 5T 2436, 2438-43).

The Company's 2021 nuclear capital expenditures totaled \$269.8 million, as listed on Exhibit A-12, Schedule B5.3, page 1, line 11, column (b). The projected capital expenditures are \$543.9 million for the bridge period ending November 30, 2023, and \$204.2 million for the projected test year (Davis, 5T 2437-2438; 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, 5T 2443-44, 2455-61. 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, 5T 2461). For example, the Visual Annunciator System (VAS) Replacement project was necessary to address component aging and obsolescence and support the replacement of the FERMI 2 VAS completed in RF21. (Davis, 5T 2460-61; Exhibit A-12, Schedule B5.3, page 4, line 4). Mr. Davis also discussed additional projects and emphasized that none of the capital expenditures for the projects include contingencies (Davis, 5T 2465-78; Exhibit A-12, Schedule B5.3, page 4, lines 3, 4, 5, 6, 8, 9, 10, 11, 13, 4, 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. He supported the expenditures as reasonable and prudent (Davis, 5T 2480; Exhibit A-12, Schedule B5.3, page 1, line 10).

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.²⁸ 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, 5T 2483). Therefore, the nuclear capital expenditures should be approved.

4. Distribution Operations (DO)

i. Overview

The Company's Distribution Operations (DO) organization focuses on the safe and reliable design, construction, maintenance and operation of the Company's electrical distribution system and subtransmission system, which are often referenced collectively as "the distribution system" (Robinson, 5T 2679).²⁹ DTE Electric's distribution system is aging, and, in many cases, equipment is operating near or beyond typical design life (Robinson, 5T 2686-87). Aging infrastructure combined with more frequent and intense weather require grid upgrades and modernization changes. These changes are necessary and foundational to support growth in distributed energy

²⁸ DTE Electric has changed the projected installation date of the Main Unit Generator project (depicted on page 4, line 2 of Exhibit A-12, Schedule B5.3) to the next refueling outage (RF23) (Exhibit S-25). See also Attachments A and B.

²⁹ DO consists of eleven suborganizations: (1) Central Engineering; (2) Regulatory Strategy and Grid Modernization; (3) Scheduling & Construction; (4) Project Management Office; (5) Operational technology; (6) Advanced Distribution Management System (ADMS) project team; (7) Regional Customer Operations; (8) System Operation; (9) Emergency Preparedness & Response; (10) Tree Trimming; and (11) Substation Operations (Robinson, 5T 2679-82).

resources (DER) and load growth associated with electric vehicle (EV) penetration, and expanding regional economic activity requires a more robust, resilient, and modern grid infrastructure. The capital investments (discussed here) and O&M expenses (discussed in section VII. C. 5) are necessary to achieve the Company's goals of providing safe and reliable electricity to customers at reasonable rates. These investments also lay the foundation for grid modernization, which customers require to support their evolving needs for greater resiliency in the face of increasingly frequent and intense storms, electrification including EVs, and integration of DER (Miller, 5T 2840).

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

The Company has two broad categories of 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: (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 (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 7, with more detail in Exhibit A-23, Schedule M3. (Hill, 5T 2736; Miller, 5T 2840-41).

The Commission previously "direct[ed] DTE Electric, in its next electric rate case filing, to provide a detailed description of each type of expenditures assigned to the emergent replacements

category” (May 8, 2020 Order in Case No. U-20561, pp 86-87). Accordingly, Mr. Hill explained that the Company tracks Emergent Replacements in three major categories: (1) Storm (investments required to restore the overhead and underground distribution systems, the subtransmission system, and substations from damage that occurs during storms);³⁰ (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); and (3) Substation Reactive (investments required to perform emergency replacements for substation equipment). (Hill, 5T 2737, 2742, 2752).

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) Single Customer Problem (Hill, 5T 2756). Table 4 (at Hill, 5T 2757-58) provides examples for each category.

The Company forecasts Storm expenditures of \$177 million for 2022, \$221 million for 2023, and \$227 million for 2024 (Hill, 5T 2737-38; Exhibit A-12, Schedule B5.4, page 2, line 3, columns (e), (f), and (g)). The 2023 and 2024 forecasts are based on a five-year (2017-2021) inflation-adjusted historical average, consistent with the methodology approved in the Commission’s orders in Case Nos. U-20162, U-20561, and U-20836. The 2022 storm forecast is less than the five-year inflation-adjusted average (\$206 million) based on actual 2022 weather (Hill, 5T 2737-38).

³⁰ A storm is declared when the number of outages exceeds 340 and the number of circuits impacted exceeds 125 (typically equivalent to 25,000 customers) (Hill, 5T 2737).

Non-storm investments are tracked in four categories: Emergent, Reactive, Corrective, and Environmental. Table 7 (at Hill, 5T 2743) provides descriptions and examples of each subcategory. The Company forecasts non-storm investments of \$265 million for 2022, \$183 million for 2023, and \$188 million for 2024 (Hill, 5T 2743-44; Exhibit A-12, Schedule B5.4, page 2, line 4, columns (e), (f), and (g)). The 2023 and 2024 forecasts are based on a five-year (2017-2021) inflation-adjusted historic average, consistent with the methodology approved in the Commission's orders in Case Nos. U-20162, U-20561, and U-20836. The 2022 non-storm forecast is higher than the five-year inflation-adjusted average (\$177 million) due to several factors driving higher actual costs. In summary: (1) global supply chain issues and raw material shortages 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) approximately a 6% increase in non-storm emergent events compared to the historical average that produced the forecast in Case No. U-20836; (5) an increase in significant non-storm events (for example, two underground cable lines failed while in service within a four-hour period in July when the system experienced peak loading, making it impossible to shift the customer load to other cables, so the Company activated its Incident Command team and worked around the clock to restore power); (6) proactive storm preparation and resource ramp-up in anticipation of extreme weather; and (7) increased use of higher-cost contractor labor (Hill, 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 and these costs should therefore be approved. This important work cannot be overstated because deferral of costs 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 conditions³¹ (Hill, 5T 2752).

AG witness Coppola recommended that the Commission “remove \$18,779,000 for the 11 months ending November 2023 and \$21,975,000 for the 12 months ending November 2024, for a total removal of \$40,754,000” from the Company’s forecasted emergent capital expenditures (Coppola 6T 3644), reasoning that the Company’s normalization adjustment “is simply compounding inflationary increases on top of inflationary increases” in a “brazen attempt to inflate forecasted capital expenditures” (Coppola 6T 3642). To the contrary, prior years’ expenditures must be expressed in a constant-dollar denomination (in this case, 2021 dollars) because the value of a dollar changes over time due to inflation (Miller, 5T 2864-65). The Commission previously approved the Company’s normalization practice (Case No. U-20561, 5/8/2020 Order, p 86) and most recently 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” (Case No. U-20836, 11/18/2022, p 63).

AG witness Coppola proposed reductions in capital expenditures of \$13,383,000 for the 11 months ending November 2023, and \$28,808,000 for the projected test year due to tree trimming

³¹ Abnormal conditions means the system is not in its designed configuration. For example, temporarily securing a broken pole until a new pole can be installed, or jumpering load from one circuit to an adjacent circuit due to a failure at a substation where the adjacent circuit was not designed to carry the additional load for an extended period of time.

reducing power outages caused by trees (6T 3689). The Company disagrees because the proposal is duplicative. The Company included cost avoidance associated with reduced equipment failures from the tree trimming surge in Exhibit A-12, Schedule B5.4, page 1, line 6, in accordance with past practice (Miller, 5T 2866-67).

ABATE witness York proposed a \$119.459 million disallowance (not broken out by period) for emergent replacements based on a four-year (2017-2020) average, 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” (4T 1138). The Company disagrees because the point of using a five-year average is to normalize the variable weather data. The Company notes that even if witness York’s proposal had any merit, the 2021 storms would only affect emergent storm capital expenditures, but witness York also applied her four-year average to non-storm and substation reactive capital expenditures, without offering any justification. Therefore, ABATE’s proposed four-year average should be rejected, and the Commission should continue to use a five-year average (Miller, 5T 2868-70).

iii. Substation Reactive

Substation Reactive investments are tracked in four subcategories: Major Equipment, Minor Equipment, Transformers & Regulators, and Non-Electrical Equipment. Table 3 (at Hill, 5T 2753) provides descriptions and examples of each subcategory. The Company forecasts expenditures of \$45 million for 2022 (consistent with the five-year (2017-2021) inflation adjusted average of \$43 million), and \$46 million for 2023, and \$47 million for 2024, based on the five-year inflation-adjusted average (Hill, 5T 2753; Exhibit A-12, Schedule B5.4, page 2, line 5, columns (e), (f), and (g)). As an example of this critical category of work, Mr. Hill discussed the work required due to the failure at the Twelve

Mile substation in 2022 and emphasized that it would not be reasonable or prudent to defer Substation Reactive work to replace critical grid equipment that has failed (Hill, 5T 2754-56).

The Commission previously ordered that “DTE Electric Company shall begin tracking equipment identified as imminent failure (near failure but has not failed) and exclude those costs from the emergent replacements’ capital program” (November 18, 2022 Order in Case No. U-20836, p 485). The Company believes that it can comply with this directive in the Substation Reactive category, where the Company performs predictive and preventive maintenance on equipment such as transformers, 120kV disconnects, 24kV/40kV breakers, distribution breakers, and regulators. The process of identifying these expenditures and tracking them will begin in 2023. The Company is not able to strictly comply with this directive in the Storm and Non-Storm categories, however, because the Company is not able to track, in all circumstances and for all equipment classes, equipment deemed to be at risk of imminent failure separate from equipment that has already failed. For example, a lineman dispatched to fix one problem, such as a broken insulator, at a location might observe a second problem, such as a rotting cross arm, after arriving at the location. The linemen would then replace the two pieces of defective equipment. This type of work is not formally planned and decisions are made in the field. It would be highly inefficient and nearly impossible for the lineman to separately track these replacements and their associated work (Hill, 5T 2758-59).

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 (Hill, 5T 2760). Further sub-subcategories and other details are discussed at Hill, 5T 2760-66.

AG witness Coppola proposed that “[g]iven the variability” in Small Load Growth projects, Customer Connections, and Relocation projects, the best approach is to use a historical average to forecast capital expenditures (6T 3645, 3650). The Company disagrees, first noting that Mr. Coppola did not propose the same treatment for all line items in this category. The Company forecasted most of the capital expenditures using prior years investments plus inflation, consistent with approaches utilized in Case Nos. U-20162, U-20561, and U-20836, with only specific projects that were not forecasted this way. Mr. Coppola proposed a five-year average for certain line items in Case No. U-20836, but now proposes a three-year average (and even then, not the same years) to different line items here, without explanation for either the different methodology or different line items. Mr. Coppola altered his methodology despite the fact that the historic values used in his calculations did not change between U-20836 and U-21297 for the projects he selected in U-20836. It is difficult to understand why Mr. Coppola changed his proposed method for forecasting expenditures/investments from U-20836 to U-21297, when the historical investments did not change. Notably, using Mr. Coppola’s prior methodology would increase the capital expenditures forecast (Miller, 5T 2858-59, 2870-72; Exhibit A-39, Schedule DD2).

Customer Connections, Relocations, and other investments, driven by customer requests, have shown consistent year-over-year growth (Exhibit A-39, Schedule DD3). The Company has consistently used the prior-year-plus-inflation forecasting method which has resulted in reasonable and accurate projections of capital actually spent (in fact, it has often been understated). In contrast, Mr. Coppola’s inconsistent use of unique averaging methods for different sub-categories of expense would not allow the Company to consistently plan its capital investments between rate cases. The

methodology that Mr. Coppola crafted for this case would also significantly under-forecast the cost that the Company is likely to incur to provide these services to its customers. Therefore, the Commission should reject the AG's proposed disallowance, and approve the funding levels requested by the Company (Miller, 5T 2873-74).

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

Regarding Customer Connections projects, Mr. Coppola recommended that the Commission "remove \$24,645,000 for the 11 months ending November 2023 and \$20,507,000 for the 12 months ending November 2024 for a total amount of \$45,132,000 from the Company's forecasted capital expenditures" (6T 3649), reasoning that "[a]s a result of the higher interest rates, new housing starts have declined significantly in 2023 and will likely continue into early 2024 before rebounding. As a result, customer connections will decline from the high level seen in 2021" (6T 3648).

The Company disagrees with Mr. Coppola's methodology as indicated above, further noting that he switched from 2020 to 2022 for Small Load Growth projects (6T 3645), to 2019 to 2021 for Customer Connections (Net of CIAC) (6T 4648). He then considered the single variable of housing starts as a proxy for forecasting Customer Connections, which is not a relevant consideration because this category of customer requested investments includes many types of customer needs, not just those reflected in the number of housing starts (Hill, 5T 2760; Miller, 5T 2877-78). Based on Mr. Coppola's methodology, the Company would have experienced a decline in category expenditures in 2022 (corresponding to the decline in housing starts), but actual expenditures increased from \$93.3 million in 2021 to \$106.7 million in 2022, which is a 13.7% increase rather than the 8.7% decrease Mr. Coppola used in his calculations to forecast 2023 and 2024 housing starts and expenditures (Exhibit A-39, Schedule DD3, line 5). Therefore, the Commission should reject the AG's proposed disallowance and approve the Company's forecasted amount (Miller, 5T 2878-79).

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

v. Tree Trimming Capital

MNSC witness Ozar proposed that the Commission “order that all projected tree trimming (that will not be a first clearing of ROW [right of way] for new lines) be moved out of capital accounts, and into O&M” (6T 3568). The Company disagrees because this proposal is based on flawed interpretations of the Uniform System of Accounts (USoA) and the Commission’s December 11, 2015 Order in Case No. U-17767 (Uzenski, 5T 1566, 1578). More specifically, Mr. Ozar 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, 5T 1579).

Mr. Ozar 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 account 364 (Poles, Towers and Fixtures) does not mention tree trimming. He then assumed that since tree trimming is not listed under account 364, it only applies to the first installation of electric lines, but not to the poles to which those lines are attached (Ozar, 6T 3563). 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 appear 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, 5T 1579).

Mr. Ozar 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 then incorrectly concluded that any succeeding clearing is maintenance expense, even if the clearing is done to enable construction work (Ozar, 6T 3563).

Mr. Ozar 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. Ozar’s accounting interpretation is not supported by a full and accurate reading of the USoA, and should be rejected (Uzenski, 5T 1580).

Mr. Ozar also referenced Case No. U-17767, where 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). Mr. Ozar suggested that the Commission’s Order should apply to all tree trimming work, “[i]rrespective of to [sic] which programs tree trimming has been assigned” (6T 3565). Again, his reasoning is faulty because 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. Ozar’s argument should be rejected. (Uzenski, 5T 1581).

vi. Strategic Capital

Strategic Capital projects and programs include work that the Company performs to improve safety, reliability and operability, and grid modernization. These investments are subcategorized into three areas or investment pillars:

1. *Infrastructure Resilience and Hardening.* These projects and programs focus on replacing aging infrastructure at risk of failure, hardening the system, and addressing areas of the system with known poor customer reliability. Exhibit A-12, Schedule B5.4, page 8 provides details, with additional details at Exhibit A-23, Schedule M4.
2. *Infrastructure Redesign and Modernization.* These projects and programs make more fundamental changes to the electrical system, such as conversion of the 4.8kV system and upgrades to the subtransmission system. Exhibit A-12, Schedule B5.4, pages 9-11 provide details, with additional details at Exhibit A-23, Schedule M5.
3. *Technology & Automation.* These projects and programs are tightly linked to the grid modernization process and include investments that develop capabilities in observability, analytics and computing, controls, and communications. Exhibit A-12, Schedule B5.4, page 12 provides details, with additional details at Exhibit A-23, Schedule M6 (Miller, 5T 2841,2846-47, 2853, 2855, 2857-59).

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

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

ABATE witness York stated that DTE has a history of underspending on Strategic Capital Programs relative to its forecasts, as these funds have historically been diverted to emergent replacements. In addition, he argues that DTE's proposed spending on these programs includes significant levels of capital expenditures for projects that are not expected to be placed in service until after the end of the projected test year and recommends that the Commission allow only the projected capital expenditures associated with projects that are expected to be in service during the bridge period and projected test year. This results in a reduction of \$1.109 billion relative to the amount proposed by the Company. (York, 4T 1139-40).

The Company disagrees with ABATE here because the Company has demonstrated its ability to execute spending consistent with its forecasting, as discussed above in response to Staff's proposed 10% reduction. ABATE's suggestion that the Company should be disallowed rate recovery for projects with in-service dates outside the test year is also inconsistent with legal and regulatory practice. Project costs can be included in rate base if they are deemed reasonable and

prudent regardless of whether they will be in service in the projected test year.³² Under well-established accounting practice, and in compliance with the Commission’s May 10, 1976 Order in Case No. U-4771, utilities may include construction work in progress (CWIP) in rate base because the revenue requirement is generally offset by an Allowance for Funds Used During Construction (AFUDC). AFUDC is applied to projects greater than \$50,000 and lasting more than six months, with an exception for environmental and other specifically ordered projects.³³ Also, project completion dates are often based on the final steps of a project, and customers receive the benefits of the work done before these final steps. For example, in conversion work customers benefit from reduced trouble events, wire downs, and improved reliability long before the final step of decommissioning an old substation. Therefore, the Commission should reject ABATE’s proposed disallowance (Deol, 2T 200; Uzenski, 5T 1512-13, 1572-73; Miller, 5T 2884-86).

MI-MAUI witness Bunch proposed that the “Commission should make approval of DTE’s plans, and recovery of costs, contingent on improved coordination with local units of government” (4T 902). This proposal should be rejected as unnecessary because the Company has worked with, and will continue to work with, local leaders to discuss and plan for major infrastructure and reliability improvements that will benefit the community (Crozier, 5T 2240; Robinson, 5T 2691-93). The proposal also raises legal and regulatory concerns because it ignores the impacts on customers if the Company’s investments were not approved (as MI-MAUI suggests), and that the Company is entitled to recover its costs of investments to provide utility service (See generally,

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

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

section IV above and the additional discussion below). The suggested assertion of local authority over utility rates also neglects that state interests prevail over local interests in utility regulation.³⁴

vii. 2021 Actual Expenditures versus U-20836 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.³⁵ 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.³⁶

³⁴ See generally, *City of Taylor v Detroit Edison Co*, 475 Mich 109; 715 NW2d 28 (2006).

³⁵ 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).

³⁶ 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).

Overall, the Company invested \$40.1 million more in 2021 than was forecasted in Case No. U-20836 (approximately 3%).³⁷ The difference was driven by increased investments in strategic capital of \$3.6 million, and higher-than-projected Emergent Replacements of \$38.5 million, including restoration of customer outages due to storm or equipment failure, where 2021 was one of the worst storm years in the Company's history, and two major substation failures were caused by a 100-year flooding event. These expenditures were necessary to restore safe and reliable service to customers, and were reasonably and prudently incurred; as such they should be approved. Also, despite the increased storm activity, the Company was still able to invest all of the projected strategic capital (Miller, 5T 2847-49; Hill, 5T 2739-41)

viii. The Company's Projected DO Capital Expenditures

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

³⁷ The Order from Case No. U-20836 included \$1,204.3 million of distribution plant expenditures in rate base, which was \$69.6 million less than the actual amount that was reasonably and prudently incurred in 2021 (Miller, 5T 2849; Exhibit A-12, Schedule B5, line 7).

AG/MNSC witness Alvarez asserted that “distribution investment plans should be presented and evaluated in litigated proceedings” (6T 3345). The Company disagrees because the DGP outlines the Company’s goals for safety and reliability in the longer term, and the investments that are planned in the shorter (5 year) term to achieve its goals. There is no need for this type of planning to be subject to a litigated case. Moreover, a non-litigated plan is what the Commission envisioned (January 31, 2017, Order in Case No. U-18014, pp 40-41), and there is no evidence that the DGP process has limited the Commission’s ability to review proposed investments for reasonableness and prudence in rate cases. The current DGP process also provides for stakeholder feedback, and the Company incorporated appropriate feedback. There is similarly no sound basis for witness Alvarez’s proposal to establish a series of workgroups to develop distribution plan requirements (6T 3343) because that has already happened. The current distribution plan requirements, which the 2021 DGP met, were developed through a series of workgroups led by Staff and included participation by the Company and stakeholders. Therefore, witness Alvarez’s proposals should be rejected (Robinson, 5T 2716-18).³⁸

A similar response applies to Staff’s suggestion that the Company “does not understand what ‘customer concerns’ are” (Wang, 7T 4778) and that the Commission should “require the Company engage interested and affected customers/communities in stakeholder meetings in future distribution plans, so their needs, wants, and concerns can be considered” (Wang, 7T 4787-88). The Company values customer and stakeholder input and has many existing touchpoints and communication channels with customers where their needs, wants, and concerns are gathered

³⁸ Various intervenors also suggested a series of conceptual proposals relating to distribution infrastructure that are incorrect or problematic on their face, or lack sufficient detail to be even thoroughly considered. Therefore, these proposals (presented in table form) should be rejected (Robinson, 5T 2721-23).

(examples of customer outreach efforts are outlined in Ms. Crozier’s testimony, 5T 2228-30). Therefore, it is unnecessary to order the Company to hold additional forms of outreach.

In addition to customer outreach, the Company’s capital investments in this case, as in previous cases, are based on long-term distribution planning processes that identify customer needs and develop and prioritize projects that provide customer benefits of improved safety and reliability in the near term, and lay the foundation for the long-term changes of increased electrification and DER adoption (Robinson, 5T 2693; Exhibit A-23, Schedule M7).³⁹ In 2022, the Company continued to focus on strategic investments, and was able to successfully invest over \$700 million of strategic capital, exceeding the \$696 million forecast in Case No. U-20836. For 2023, the Company forecasts \$811 million of strategic capital, which is \$5 million less than the \$816 million forecast in Case No. U-20836. The change is driven by the increased focus on the need to increase the project portfolio in the Infrastructure Redesign and Modernization pillar, as well as increased investments in the 4.8kV Circuit Automation program, and a reduction in Infrastructure Resilience and Hardening (Miller, 5T 2850-51; Exhibit A-23, Schedule M2).

Mr. Kryscynski explained that strategic investment programs are evaluated against seven impact dimensions in the Company’s Global Prioritization Model (GPM), which is a “best fit, most-reasonable cost” framework that the Company developed to assess the impact that strategic investment programs and projects are expected to have on the grid in order to meet customer needs (Kryscynski, 3T 385-90). Table 4 at Kryscynski, 3T 392, shows the top 50 Strategic Capital investments (Kryscynski, 3T 390-92).⁴⁰

³⁹ The Company intends to file another plan in September 2023, as directed by the Commission, and that updated plan will discuss progress on grid modernization and reflect the investments discussed in this case. (5T 2695-96).

⁴⁰ Tree trimming is a high-priority strategic program, but it is not in the table because the costs are O&M, and not capital (Kryscynski, 3T 390). See section VII. C. 5. ii for a further discussion regarding tree trimming.

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

AG/MNSC witness Alvarez asserted that the Commission should order "risk-informed benefit-cost analyses," which he described as "[i]n most respects . . . the same as benefit-cost analyses: a simple comparison of the benefits of a project or program to customers over an investment's expected lifetime (depreciation period) to the costs of a project or program to customers (defined as the present value of associated revenue benefits over time)." (6T 3346) He further proposed a formula for a "risk-informed benefit calculation," that purportedly can be used to estimate the value of risk reduction to customers and asserted that the "calculation is simple and intuitive." *Id.* To estimate the benefit (in dollars) of a reduction in the likelihood of an adverse event (i.e., a risk) delivered by an investment (let's call it investment 'a'), one need only multiply the reduction delivered by investment (a) in the likelihood (percent) of an adverse event (b) by the consequence (in dollars) associated with adverse event (b) if it occurs." (Alvarez, 6T 3346).⁴¹ He further recommended that the Commission "order that risk-informed benefit-cost analyses be completed on any distribution investment plan project or program with capital spending in excess

⁴¹ Mr. Alvarez offered support for his proposed formula that does not include the formula, but instead only presents steps to build a cost-benefit approach to identify and assess risks (Kryscynski, 3T 424-25; Exhibit A-44, Schedule III).

of \$100,000, and to include those analyses in plan workpapers . . . [and] that risk-informed decision support be used to select the projects and programs for a distribution investment plan from a portfolio of potential investments” (Alvarez, 6T 3353).

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

Mr. Alvarez attempted to support his equation by asserting that “benefits” are “not always easy to calculate” (6T 3346). That is true, at least to some extent (for example, regarding improvements to public safety), but Mr. Alvarez’s proposed formula does not improve the situation, and he does not suggest a method for converting benefits to monetary amounts. Moreover, attempting to provide a monetary amount for each impact dimension would create more ambiguity by introducing a new variable that is inherently subjective. For example, reducing wire downs is a safety improvement, but there is no method or industry best practice for assigning a dollar value to reduced wire downs. The Company could assign a value (as could others and we could argue about them), but ultimately there is no hard data to conclusively establish that any assigned dollar amount is correct. Thus, there would be no value to the Company or its customers, and the Commission

would simply waste its resources chasing something that is inherently indeterminate (Kryscynski, 3T 427-28).

ix. 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 increasingly frequent and more severe weather including high winds and storms, addressing frequent outage circuits, and replacing aging infrastructure. The Company projects capital costs associated with these projects of \$692.3 million for 23 months ending November 30, 2023, and \$244.5 million for the projected test year (Elliott Andahazy, 3T 506; Exhibit A-12, Schedule B5.4, page 8; Exhibit A-23, Schedule M4). The Company plans to invest in 30 different programs in this category. Seven warrant particular discussion: (1) Substation Risk, (2) Breaker Replacement, (3) Cable Replacement, (4) Underground Residential Distribution (URD) Replacement; (5) 4.8 kV Hardening, (6) Pole and Pole Top Maintenance and Modernization (PTMM), and (7) Frequent Outage Programs (CEMI), as discussed below.

As a preliminary matter, AG/MNSC witness Stephens suggested that he performed a "risk-informed benefit cost analysis" based on AG/MNSC witness Alvarez's formula (Stephens, 6T 3387). As indicated above, the Company disagrees with Mr. Alvarez's proposed formula and

related propositions, in part because putting a monetary value on certain benefits like safety is inherently subjective.

Mr. Stephens indicated a belief that Occupational Safety and Health Administration (OSHA) recordable incidents are the driver to measure the success of capital investments associated with safety (e.g., Stephens, 6T 3396). The Company disagrees because OSHA recordable incidents are a metric used for employee injuries that meet a certain threshold. They are not a measure of public safety risk reduction. OSHA recordables are also a lagging metric that measures safety incidents after they happened, instead of a leading metric to proactively prevent accidents and injuries. The Company strives to proactively improve the safety of its infrastructure for both the public and its employees, including investments for safety not related to OSHA recordable incidents. Examples include the Port Huron project, which had exposed energized equipment that caused a safety and operating concern (Exhibit A-23, Schedule M4), and the Pontiac Vaults, which “[d]ue to the confined space in the vaults, there is also a shock hazard to personnel entering the vaults” (Exhibit A-23, Schedule M7, section 8.19, page 210). The Company considers customer and employee safety to be a high priority and will continue to proactively invest to improve safety. Requiring OSHA recordable incidents to have occurred prior to implementing safety investments (as Mr. Stephens suggests) would not be prudent. In addition to failing to be proactive, using the proposed measure in Mr. Alvarez’s formula (as Mr. Stephens suggests) would also understate the benefits of improvements, and the use of that formula (as Mr. Alvarez suggests) would lead to safety improvements not being made (Elliott Andahazy, 3T 566-68, 589).

1. Substation Risk.

The Company’s Distribution Grid Plan (DGP; Exhibit A-23, Schedule M7) proposes to replace equipment with high potential stranded load and substation asset condition. Mr. Stephens

asserted that: “Unless and until the Company produces a risk-informed benefit-cost analysis for every substation risk reduction project, or for its various substation equipment replacement programs, I recommend recovery of substation risk cost be disallowed in full and removed from future capital spending plans” (Stephens, 6T 3391).

The Company disagrees because it already did a risk-informed benefit analysis for Substation Risk projects using the GPM, as discussed above. There are also additional errors and deficiencies in Mr. Stephens’ application of Mr. Alvarez’s formula. For example, Mr. Stephens suggested that he performed a robust suite of analyses. (6T 3387)(“Every time I have completed this analysis, the premature replacement of equipment operating safely and reliably, just because it is old, is not cost effective.”) Yet, his testimony only shows one attempt at completing the analysis on circuit breakers, as further discussed below. He also acknowledged that “Time constraints prohibited me from evaluating all these projects in the instant Application in detail” (Stephens, 6T 3386). Mr. Stephens also did not support his speculation that the Company replaces equipment “just because it is old,” and the record shows he is incorrect. The DGP lays out specific replacement factors for various pieces of substation equipment. For example, there are four criteria for replacing circuit breakers (Interrupting medium, High O&M costs, Unavailable Parts, and Known Performance Issues), none of which just depend on the age of the equipment (Exhibit A-23, Schedule M7, page 168). (Elliott Andahazy, 3T 569-70, 574).

Mr. Stephens suggested that substation risk projects are not worth their costs because “[he] completed a risk-informed benefit cost analysis of the type Mr. Alvarez describes in his testimony on the breaker replacement program in the Company’s DGP.” (Stephens, 6T 3386-87). His analysis is incomplete, however, because there is more to the substation risk project than breaker replacement, as indicated above. In addition, Mr. Stephens admits that the program “replac[es] a

variety of equipment types in ‘high risk’ substations, including disconnect switches, circuit switchers, circuit breakers, and voltage regulators.” (Stephens, 6T 3386). Mr. Stephens also did not offer any support for the parameters that he used in Mr. Alvarez’s formula, nor did he fully consider all relevant factors. For example, failure of a breaker with no available spare parts could lengthen customer outages and result in significant additional costs for the deployment of generators or portable substations to restore customers. Mr. Stephens also failed to consider the maintenance cost savings over time by replacing an obsolete oil-breaker with a modern breaker (Elliott Andahazy, 3T 571-72, 577).

Mr. Stephens asserted that, “Risk-informed cost benefit analyses are completely data-driven driven, and represent the most objective foundation for decision-making available” (6T 3388-89). The Company agrees in principle with the use of risk-informed data-driven analysis, which is why the Company uses the GPM, with factors including safety risk, avoided costs, load relief, and reliability improvements. In contrast, Mr. Stephens’ analysis is incomplete and incorrect. He did not attempt to quantify any benefit other than reliability improvements, and other measures (such as safety improvements) cannot be objectively monetized. Therefore Mr. Alvarez’s formula, and Mr. Stephens’ application of it, are not “completely data driven.” Mr. Stephens’ application of the formula is entitled to no weight and should be rejected. There is no sound basis to disallow substation risk capital just because the Company did not perform the AG/MNSC’s flawed analysis (Elliott Andahazy, 3T 572-73, 575, 577).

Mr. Stephens also failed to address the details regarding each project, how substations are selected and the impact on customer reliability of those that have failed, and potential failures (reflected in Exhibit A-23, Schedule M4, pages 6-41; Exhibit A-23, Schedule M7, pages 232-40). He instead superficially mischaracterized the program as simply “premature equipment

replacement” (Stephens, 6T 3385). In addition to the discussion above, replacing equipment that has already failed such as the Drexel project and McGraw project, and eliminating equipment that is a safety hazard such as the Port Huron project, is not “premature equipment replacement.” (Elliott Andahazy, 3T 575-77). As stated on page 237 of Exhibit A-23, Schedule M7 (in describing the historic flooding events in 2021 which impacted thousands of southeast Michigan residents as well as electric service and other infrastructure, “Two DTEE substations in Detroit, McGraw and Scotten, flooded as a result of this storm. The damage that resulted from multiple electrical faults caused by the flood left much of the equipment, including breakers, and buses unrepairable at McGraw.” This is a clear indication that the equipment did, in fact, fail at McGraw and the Company was unable to repair said equipment.

In summary, Mr. Stephens did not evaluate substation risk projects, nor did he propose to disallow any specific project, nor did he dispute the Company’s supporting documentation. Instead, he mischaracterized the program as a “premature replacement” program and broadly proposed to disallow all of it based on his flawed application of Mr. Alvarez’s flawed formula, failing to even recognize (let alone quantify for a “data-driven” analysis) benefits such as safety improvements and the replacement of failed equipment. Therefore, Mr. Stephens’ proposed disallowance should be rejected (Elliott Andahazy, 3T 577-78).

2. Breaker Replacement.

This program replaces obsolete circuit breakers,⁴² 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

⁴² A circuit breaker is an electrical switch designed to isolate faults that occur on substation equipment, buses, or circuit positions, and thereby minimize equipment damage (Elliott Andahazy, 3T 542).

benefits include enhanced safety, reduction of substation outage risk caused by breaker failures, improved reliability, reduction in reactive expenditures due to breaker failures, added ability to use SCADA controls, and the reduction of outage duration provided by SCADA capability. Breakers are prioritized for replacement based on criteria that maximize these benefits. The Company plans to replace 35 breakers in 2023, and 36 breakers in 2024, consistent with past years (Elliott Andahazy, 3T 542-44).

AG/MNSC witness Stephens did not propose a specific disallowance for this program, but it is unclear what he proposes. As indicated above, Mr. Stephens indicated that he performed an analysis of circuit breaker replacement in connection with his proposal for a Substation Risk disallowance. He proposed disallowances of \$47,788,000 in the bridge period, and \$13,412,000 for the projected test year (6T 3401), which match the Company's requests for the Substation Risk projects, but he cited Exhibit A-33, Schedule X1, which relates to the Breaker Replacement program.

To the extent that Mr. Stephens suggests a further disallowance for the Breaker Replacement program, it should be rejected as unsupported. The Company also incorporates its prior discussion demonstrating that Mr. Stephens' application of Mr. Alvarez's suggested risk-informed benefit cost analysis has numerous flaws and is entitled to no weight, so any recommendation based on it should be rejected (Elliott Andahazy, 3T 579-80).

3. 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 cable type, vintage, failure history, system impacts, and cable loading. The Company replaced 4.9 miles of system cable in 2022, and is targeting approximately 17 miles in 2023, and 19 miles in 2024. This ramp-up of cable replacement efforts will benefit customers through reduced risk of lengthy outages, improved reliability, and lower reactive costs (Elliott Andahazy, 3T 535-37, 580-81).

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. The URD program prioritizes and replaces URD cable based on multiple factors including vintage, number of failures, and number of customers affected by those failures. There are approximately 11,000 miles of URD cable on the system, with approximately 2,100 miles (19%) being pre-1985 (non-tree-retardant).⁴³ The program also replaces live-front transformers with dead-front transformers (Elliott Andahazy, 3T 537-39, 581).⁴⁴

The Company has successfully ramped up its underground replacement program in recent years and is confident that it will be able to execute the URD Replacement program presented in this case (45 miles in 2022; 80 miles in 2023; and 87 miles in 2024). Customers benefit from improved reliability because the program will reduce the number and length of customer interruptions due to URD cable failures. Customers also benefit from a reduced risk of multiple failures and long-duration outages (Elliott Andahazy, 3T 540-42).

⁴³ "Treeing" refers to the tree-like pattern of insulation breakdown. The breakdown typically originates at an impurity or defect in the solid insulation and grows gradually over time to resemble the branches of a tree, ultimately leading to a cable failure (Elliott Andahazy, 3T 537-38).

⁴⁴ Live-front transformers have no protective coverings over energized equipment, and therefore pose a potential safety risk to crews performing work once the external transformer covering is removed (Elliott Andahazy, 3T 539).

AG/MNSC witness Stephens recommended disallowance of capital expenditures for both programs, asserting “unless and until the Company produces a risk-informed cost-benefit analysis that indicates its cable replacement programs are cost effective, I recommend recovery of cable replacement costs be disallowed in full, and removed from future capital spending plans” (6T 3394). The Company disagrees because, as indicated above, (1) the Company already uses risk-informed decision making as part of the GPM, (2) witnesses Alvarez and Stephens do not offer any evidence to show that their methodology is better (or even that it is “data driven” as it purports to be rather than subjective), and (3) considerable evidence indicates that it would be worse because it fails to consider all relevant criteria, such as safety improvements (Elliott Andahazy, 3T 581-82).

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

The quote was part of a discovery response (Exhibit A-42, Schedule GG3) regarding how the Company selects URD cable replacement. Mr. Stephens neglected (1) the significance of “treeing” (insulation breakdown on pre-1985 URD cable), (2) the significance of “same cable type” in the quote from the discovery response, and (3) non-tree retardant XLPE URD cable is one of the

replacement factors for the program. Treeing of cable insulation is a well-known failure in URD cable throughout the industry. If an area is experiencing multiple failures, then in the Company's SMEs' experience that means that the adjacent cable is likely to have the same type of insulation and will likely experience additional failures. System cable has a similar insulation reliability concern relating to "treeing" for pre-1990 cable with XLPE insulation, and there are four cable types with known limitations or defects that are included in the Company's replacement criteria (Elliott Andahazy, 3T 583-84; Exhibit A-23, Schedule M7).

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

4. 4.8 kV Hardening.

The 4.8 kV Hardening program was developed as a cost-effective way of providing improvements in safety and reliability in areas of Detroit that have abandoned Detroit Public Lighting Department (DPLD) arc. The Hardening program is a near term program, which can be constructed at a faster pace than the longer-term plan to convert the entire 4.8 kV system in the city of Detroit, which is estimated to cost over \$4 billion and take more than a decade to complete. Primary components of the program include replacing or reinforcing poles as necessary, replacing wooden cross-arms with fiberglass cross-arms, removing DPLD arc wire (consistent with the

Commission’s Order in Case No. U-18484) and DPLD distribution wire from DTE Electric-owned equipment, removing service lines to abandoned properties, and trimming trees to support construction activities (Elliott Andahazy, 3T 506-509). The Commission previously agreed with the ALJ, who “agreed with DTE Electric that the 4.8 kV hardening proposal is economically efficient and that a more complete conversion of the system to 13.2 kV would be expensive and provide limited incremental benefit” (May 2, 2019 Order in Case No. U-20162, pp 31, 33).

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

The Company hardened 475 line-miles in 2022, and expects to harden 346 miles in 2023, and approximately 1,464 miles total from 2018-2023. Through year-end 2023, the Company also expects to have removed approximately 50% of the arc wire that is co-located with Company-owned assets.⁴⁵ Customers have benefitted because the program has proven very effective in

⁴⁵ The remainder of arc wire co-located with Company-owned assets is intended to be removed through the 4.8kV Conversion Program (Elliot Andahazy, 3T 512).

improving the safety, reliability, and resiliency of circuits. Circuits that were hardened experienced a 26% reduction in wire downs vs an increase of 20% in the control group; a 46% reduction in All-Weather SAIFI vs an increase of 26% in the control group, and a 73% reduction in SAIDI ex-MEDs vs a 5% reduction in the control group. Going forward, the Company will be ramping up work capacity for converting circuits to higher voltages, thus decreasing the investment in the 4.8kV Hardening Program and increasing the investment in the 4.8kV Conversion Program (Elliott Andahazy, 3T 510-15).

AG/MNSC witness Stephens proposed that “the costs of this program be disallowed in full and removed from future capital spending plans” (6T 3397), based on his use of Mr. Alvarez’s risk-informed benefit cost formula to claim that “the 4.8kV hardening program is not a remotely cost-effective way to improve reliability,” plus various unsupported and speculative assertions about safety. (6T 3396).

The Commission should reject this argument because, as indicated above, (1) the Company already uses risk-informed decision making as part of the GPM, (2) witnesses Alvarez and Stephens do not offer any evidence to show that their methodology is better (or even that it is “data driven” as it purports to be rather than subjective), and (3) considerable evidence indicates Mr. Alvarez’s methodology would be worse because it fails to consider all relevant criteria, such as safety improvements (Elliott Andahazy, 3T 586).

Mr. Stephens’ analysis is also flawed in this context because it does not capture all benefits of the 4.8kV Hardening program. The analysis focuses only on reliability improvements, but the program also provides additional benefits including safety improvements (measured by wire down reductions), avoided O&M and reactive capital costs (e.g., reduced reactive costs due to reduced

events requiring the dispatch of a line crew), and regulatory compliance (Elliott Andahazy, 3T 512-14, 587-88; Exhibit A-23, Schedule M7, page 243; Exhibit A-23, Schedule M4, p 44).

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

The Company disagrees with Mr. Stephens on this point for three primary reasons, First, Mr. Stephens assertion is dangerous as it gives the false impression that downed arc wire is safe. It is incorrect to assume that all DPLD wire downs are non-electrified. Instead, they might become energized either directly or through contact with energized wires. Indeed, the Commission also requested that the Company remove arc wire because downed DPLD wires present a safety hazard (Elliott Andahazy, 3T 588).

Second, Mr. Stephen's assertion that "the Company indicates it does not track safety incidents on its 4.8kV system" is in reference to a discovery response asking the Company to, "[p]rovide the count of OSHA-reportable safety incidents that occurred on the 4.8KV system from 2018-2022." As discussed above, the Company disagrees that OSHA recordable incidents are appropriate to measure the success of capital investments associated with safety because OSHA recordable incidents are a lagging metric used for employee injuries that meet a certain threshold. OSHA incidents do not capture hazards associated with the public (Elliott Andahazy, 3T 567-68, 589).

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

Mr. Stephens’ assertion that “the 4.8kV hardening program is not a remotely cost-effective way to improve reliability” (6T 3396) also misses the mark because the program was created first and foremost as a *safety* program. The program aligns with the Commission’s expectation that the Company remove arc wire, as reflected for example in the November 18, 2022 Order in Case No. U-20836, p 94. With that said, however, the program also provides significant reliability benefits as a secondary benefit to safety (Elliott Andahazy, 3T 506-507, 512-14, 590-91).

Mr. Stephens continues, that “[i]t appears that a more cost-effective way to reduce wire down events would be to remove the DPLD wire, and not take on the capital cost of hardening” (6T 3396). In addition to the discussion above regarding the flawed bases for that assertion, Mr. Stephens also neglected to consider that just removing the arc wire without doing additional work on the pole tops would leave the cross arms unbalanced, which could increase wire downs, with corresponding increases in outages and reactive costs (Elliott Andahazy, 3T 509, 591).

Therefore, the Commission should reject Mr. Stephens’ proposed disallowance 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.

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

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

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

Accordingly, Ms. Elliott Andahazy explained that in 2019 the Company added enhanced specifications, including changes to the poles and pole-top hardware used, and to testing and inspection processes, based on benchmarking and other learnings (Elliott Andahazy, 3T 517-20; Exhibit A-23, Schedules M8 (Wood Pole Maintenance Specification) and M9 (Pole Top Maintenance Specification)). The more robust specifications have resulted in increased PTMM investments, since the amount of work required per circuit mile increased (Elliott Andahazy, 3T 521-23).

The Company inspects poles on a 10- to 12-year cycle, and historically has achieved this target by using various inspection processes. In 2022, the Company discontinued using Joint Use inspections⁴⁶ for this purpose, and began exclusively using the PTMM, 4.8kV Hardening, and 4.8kV Conversion programs for pole and pole top hardware inspections. This has resulted in a greater number of inspections performed by the PTMM program, at the enhanced specifications discussed above (Elliott Andahazy, 3T 524-25).

The Commission previously directed:

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

The Company has supplied the cost breakdown, and the issue has otherwise become moot. Company witnesses Elliott Andahazy and Uzenski explained that pole inspection and testing costs are reflected on Exhibit A-12, Schedule B5.4, page 8, line 12 (4.8 kV Hardening, which is discussed in the section above) and line 13 (PTMM, which is discussed in this section). Exhibit A-12, Schedule B5.4.8 provides a breakdown of those costs at lines 1 - 5 (4.8kV Hardening) and 6 – 11 (PTMM). Inspection and testing costs are shown at line 2 (4.8kV Hardening) and 7 (PTMM). Inspections for the 4.8kV Hardening program were concluded in 2022. The Company changed its accounting policy, effective January 1, 2023, to shift inspection costs associated with the PTMM program to O&M (Elliott Andahazy, 3T 530-31; Uzenski, 5T 1506-1507).

⁴⁶ 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, 3T 525).

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

MNSC witness Ozar proposed that “the projected PTMM capital expenditure be set at a level of \$63.445 million, which is the same level projected in the 2023 bridge period” (6T 3560). This indicates a disagreement with the Company’s reasons for increasing investments (6T 3545-60). The Company maintains that its reasons are valid and fully support its proposed level of funding, as indicated above and further discussed below.

Mr. Ozar indicated that the enhanced standards were adopted years ago, so they are not “new” and therefore are not contributing to recent investment increases (e.g., 6T 3547). This is inaccurate for two primary reasons: (1) Although the enhanced standards were formally adopted in the second half of 2019, their full implementation required extensive retraining of the Company’s workforce, which did not begin until 2020; and (2) The COVID-19 pandemic significantly hampered the Company’s ability to perform inspections in 2020. Therefore, the full effects of the new standards and inspection practices did not begin to generate significant additional work volume until 2021 and were not fully realized until 2022. The enhanced standards have identified more poles and pole top equipment locations to be replaced per circuit mile inspected, with corresponding increases in the overall scope of work and associated investment levels. Mr. Ozar’s further

suggestion that the Company's inspection cycle is only "marginally shorter" than past years (6T 3547) also neglects that the Company relied on Joint Use inspections prior to 2022 to reach its target of a 10-12 year inspection cycle. The expenditures for these Joint Use inspections were not captured under the PTMM program, and these Joint use inspections identified significantly fewer defects per circuit mile, since they were focused on maintaining proper clearance between utility and telecommunication lines rather than the condition of pole top equipment (Elliott Andahazy, 3T 522-25, 594-96).

Mr. Ozar suggested that the enhanced standards would decrease failure rates through earlier detection of pole decay and remediation before failure, and that increased PTMM is not being driven by the backlog of distribution assets that failed recent inspections and were not previously remediated (e.g., 6T 3547-49). These suggestions conflate two different categories of work that are separate regarding how they are managed and where expenditures are captured: (1) in-service failures of pole and pole top equipment, which are captured in the Non-Storm and Storm categories and do not appear in the Pole/PTMM program; and (2) poles and pole top equipment that fail PTMM visual and physical inspections, which are remedied under the PTMM program. The PTMM program includes expenditures for inspections and for remediating poles and pole top equipment that fail those inspections. The existence of a PTMM backlog means that not all of the work identified in prior years was performed in those years (because the Company is identifying more defect locations per circuit mile than it identified historically) and supports the Company's argument that the PTMM program needs increased investment to accomplish its scope of work under the enhanced standards and inspection practices (Elliott Andahazy, 3T 522-23, 593-94, 598-600).

Mr. Ozar further asserted that “the persistent backlogs, exceptionally large variance in inspections from year to year, and unreasonable level of modernization, demonstrate substantial mismanagement of the program.” (6T 3547-48). The Company disagrees. Addressing the criticisms in order, the Company incorporates the discussion above regarding backlogs. Inspection totals were 74,000 to 114,000 from 2017-2022, which is not an “exceptionally large variance in inspections from year to year,” particularly since the only year with a significant variance was 2020 and was due to the COVID-19 pandemic. Also as indicated above, the Company made changes to the PTMM program specifications in the second half of 2019, which were fully implemented after some delay due to COVID-19. Mr. Ozar’s assertion of an “unreasonable level of modernization” is similarly unfounded. The PTMM program only replaces poles and pole top equipment that fail inspections or are known to have manufacturing defects that lead to elevated failure rates. The modernization aspect of PTMM means that when wooden poles, wooden crossarms, porcelain cutouts, and porcelain insulators fail inspections and are replaced, they are done so to current, more resilient standards, which include stronger poles, fiberglass crossarms, and polymer cutouts and insulators. Mr. Ozar also “acknowledge[d] that for those poles that are inspected and deemed in need of replacement, that the stronger and taller poles meeting the new engineering standards may cost more than poles meeting the previous standards” (6T 3549). Therefore, there is no sound basis for Mr. Ozar’s criticisms (Elliott Andahazy, 3T 600-601).

Mr. Ozar further suggested “that DTE move to a risk-based pole and pole top maintenance program” (6T 3557). The Company disagrees because the current PTMM program already accounts for risk, as only assets that fail inspection and are deemed to be at high risk of failure are replaced. The Company also benchmarked other utilities in the Midwest and Northeast and determined that it is common practice for utilities to manage their PTMM programs on a 5 to 10-year cycle. A 10-

year inspection cycle also comports with Staff's November 20, 2009 Utility Pole Inspection Program Investigation Staff Report. (Elliott Andahazy, 3T 603-604).

Therefore, and as further discussed on the record, MNSC's criticisms of the PTMM program and proposed investment cap should be rejected, and the Pole/PTMM program should be fully funded.

6. Frequent Outage Programs.

There are three primary programs under Frequent Outage programs: (1) Customer Excellence (CE), which provides rapid solutions to small pockets of customers experiencing poor reliability; (2) Frequent Outage (a/k/a Customers Experiencing Multiple Interruptions, or CEMI), which performs improvements to either portions of a circuit (customer pockets) or entire circuits as appropriate; and (3) Strategic Reliability Improvement Program (SRIP), which is a new program that began as an outcome of the Pre-Storm Season Strengthening process (Elliott Andahazy, 3T 544-46).

The level of investment in Frequent Outage programs increased in 2022 primarily due to the new Pre-Storm Season Strengthening process identifying additional work. Following 2021's historic storm season, impacting a significant number of customers, this new process identified 527 circuits that required some type of work to improve reliability. Based on the scope of work needed, 262 of these circuits were assigned to the CE program and were completed before the 2022 storm season, driving the more than 40% increase in total CE circuits completed from 2021 to 2022 (Elliott Andahazy, 3T 546; Hill, 5T 2741).

This work continues, so the level of investment in Frequent Outage Programs remains elevated in 2023 and 2024. The 2022-2023 Pre-Storm Season Strengthening plan includes 385

distribution circuits and 13 subtransmission circuits, divided between the CE and SRIP programs. The 2023-2024 plan includes 427 circuits (Elliott Andahazy, 3T 546-47; Hill, 5T 2741).

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. Circuits that were identified in the 2022 Pre-Storm Season Strengthening process and assigned to Frequent Outage programs saw a 69% reduction in all-weather SAIFI, as compared to 2021 during the peak storm months of June through September (Elliott Andahazy, 3T 548; Hill, 5T 2741).

b. Infrastructure Redesign and Modernization.

Infrastructure Redesign and Modernization projects and programs fundamentally upgrade the electrical system and fall into three primary areas: (1) Subtransmission Redesign and Rebuild; (2) Conversion to higher voltage (City of Detroit Infrastructure (CODI) and Conversions); and (3) System Loading (Deol, 2T 195-96); Exhibit A-12, Schedule B5.4, pp 9-11 (listing projects); Exhibit A-23, Schedule M5). The Company projects capital expense associated with these projects of \$475.4 million in the 23-month bridge period ending November 30, 2023, and \$526.4 million in the projected test year (Exhibit A-12, Schedule B5.4, p 11, line 111, columns (b), (f), and (g)). Significant programs include Subtransmission Redesign & Rebuild, 4.8kV Conversion (including 4.8kV ISO Conversion) and 8.3kV CC: Pontiac Conversion, City of Detroit Infrastructure (CODI), Strategic Undergrounding, Primary Deconductoring, and System Loading, as discussed below.

As a preliminary matter, AG/MNSC witness Stephens asserted that “DTE appears to be basing its need to convert all its circuits to 13.2kV within 15 years on EV growth,” referencing the Company’s 2021 Distribution Grid Plan (DGP, Exhibit A-23, Schedule M7) and the Company’s directionally-plausible forecast for EV growth (6T 3373).

There are many concerns with Mr. Stephens' assertion. First, the Company does not assert any need to convert all of its circuits in 15 years. Exhibit A-23, Schedule M7, page 319 reflects that the conversion is likely to take decades, but the Company has an aspirational goal to convert in 15 years. In any event, this case involves shorter-term investments projects that support current capacity and reliability needs, not future electrification needs as a driver, as further discussed below (Deol, 2T 241).

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

Mr. Stephens further asserted that "[i]t appears to me that the Company's Area Load Analysis, completed in 2020, artificially de-rated the capabilities of circuits and substations" (6T 3375) and "[i]t wasn't until I reviewed the EV loading workpapers [i.e., the directionally-plausible forecast discussed above] late in discovery that I realized the capabilities the Company was assigning to its substations were subjectively determined rather than based on the manufacturers' nameplate capacity ratings" (6T 3381).

To the contrary, the Company's substation ratings are *not* subjectively determined or artificially de-rated. The Company bases its substation ratings on defined equipment ratings. Mr. Stephens definition of substation capacity (6T 3380) is similar to the Company's definition, as both use equipment rating to determine capacity. The only difference is that the Company includes single

contingency consideration⁴⁷ in its planning. This is prudent and otherwise appropriate because if the Company did not rate substations on a single contingency, then the Company would experience additional failures as adjacent equipment would quickly become overloaded, causing cascading failures resulting in customer outages (Deol, 2T 229, 239-40, 243, 366, Exhibit A-47, page 1).

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

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

The Company disagrees because it provided detailed analysis for each of its capital projects, including how they are developed, vetted, and ranked (See, e.g., Kryscynski, 3T 385-95, 426-27; Miller, 5T 2840-44; Exhibit A-23, Schedules M3-M6). In contrast, Mr. Stephens did not offer any support for why a multi-program 50% disallowance would be correct, or how a 50% reduction

⁴⁷ A single contingency condition is one in which a piece of equipment fails, and an adjacent piece of equipment is required to pick up the load normally handled by the failed equipment in order to maintain uninterrupted power for customers (Deol, 2T 240).

allegedly “will be much more than adequate.” Mr. Stephens also did not assess the safety, reliability, or other impacts that a 50% disallowance would have on any project, nor did he directly dispute the purpose, necessity, reasonableness or prudence of the projects, or the Company’s ability to execute them. Therefore, Mr. Stephens’ arbitrary across-the-board 50% disallowance merits no weight and should be rejected (Deol, 2T 245-47).⁴⁸

1. 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. Benefits include safety improvements, improved reliability and operability, and increased capacity (Deol, 2T 216-24, 248-50; Exhibit A-23, Schedule M7 DGP, pp 294-95).

AG/MNSC witness Stephens proposed a 50% disallowance, essentially reasoning that capital investment in subtransmission projects could be slowed down dramatically at low risk, based on his misuse of the EV loading workpapers (as he calls them) and misperceptions that the Company subjectively determined, and de-rated, its substations (6T 3379-84). The Company disagrees, incorporating the discussion regarding preliminary matters above. Company witness Deol further discussed the nature of the subtransmission system and why the program is necessary,

⁴⁸ Mr. Stephens’ reference to a “new and improved distribution planning process” referred to the risk-informed benefit-cost analysis suggested by AG/MNSC witness Alvarez. The Company incorporates its prior discussion explaining why the suggested analysis is unnecessary and otherwise lacks merit, particularly as applied by Mr. Stephens.

including the need to address planning criteria violations, and reliability and safety benefits (2T 248-51).

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

Mr. Stephens also neglected the fact that planning criteria violations are a measure of reliability because they relate directly to the subtransmission system’s availability to serve customers.⁴⁹ Mitigating these planning criteria violations through substation investment projects is required to continue to serve customers’ growing loads during normal system configurations, and to provide the necessary system redundancy to avoid the risk of large customer outages when contingency scenarios occur. The Company also provided a list of circuits in discovery that shows over one-third of the system violates planning criteria, and what planning criteria are violated. Mr. Stephens did not dispute the merits of using planning criteria violations as a measure of reliability.

⁴⁹ Planning criteria violations are areas of the system that are not in specification. They have thermal overloads or low voltage during normal or contingency conditions. Thermal overloads can lead to the reduced life of electrical equipment and potentially catastrophic failure. As Company witness Deol explains, low voltage could damage customer equipment and ultimately lead to an outage for parts of or entire substations (2T 253).

Instead, he misused the EV “loading workpapers” in an attempt to disprove the validity of the violations themselves, asserting that the Company subjectively rates substations (6T 3382). As discussed above, the Company’s substation capacity ratings are not subjective, but instead are based on equipment ratings, and the Company must consider contingency when planning. Mr. Stephens also did not address the specific purpose, necessity, reasonableness, prudence, or investment for any specific project, or the Company’s ability to execute the associated work. Therefore, Mr. Stephens’ proposed 50% disallowance should be rejected. (Deol, 2T 253-55).

2. 4.8 kV and 8.3kV Conversion Projects.

The 4.8kV conversion project is aimed at upgrading the aged 4.8 kV system to higher grid voltage by building new substations and upgrading circuits to add capacity to serve growing load, address safety issues on the 4.8kV system, and to address deteriorating reliability performance due to aging electrical infrastructure (2T 197-201). Converting all of the 4.8kV substations and circuits will be a significant long-term investment. The near-term (five year) projects reflect investments that address current loading constraints and safety considerations on the system (Deol, 2T 197-201, 258; See also Exhibit A-23, Schedule M7, section 11.3.2). Company witness Deol provided additional details on two representative projects for a deeper understanding of the drivers, scope, and benefits of 4.8kV conversion: (1) I-94 Substation and Circuit Conversion (Promenade) (2T 202-203), and (2) Lapeer – Elba Expansion and Circuit Conversion (Apollo) (2T 204-205).

The 4.8kV ISO Conversion program relates to the Company operating some circuits at 4.8kV that are fed from a 13.2 kV substation, which are known as isolation down areas (ISO down). The program for converting ISO down areas is aimed at upgrading portions of the circuits to a higher voltage, thus adding capacity to serve existing load, improve safety by reducing wire downs,

improve jumpering capability to adjacent 13.2kV circuits, and to address deteriorating reliability performance due to aging electrical infrastructure. (Deol, 2T 205-208).

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

AG/MNSC witness Stephens proposed a 50% disallowance, recommending that, "going forward, 4.8kV and 8.2kV [sic, 8.3kV] capital spending be cut by ½, at least until a more complete and rigorous forecast of EV adoption and its impacts on circuit- and substation-specific loads at circuit- and substation-specific peaks can be completed, and until accurate substation-specific capacity ratings can be developed" (6T 3376).

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

reasonableness of replacing the 4.8kV and 8.3kV systems at this time due to their age and other shortcomings including safety and reliability issues, as indicated above and further detailed on the record. (Deol, 2T 24-27, 2T 265-266).

Mr. Stephens also acknowledged that “capacity must be upgraded over time as load grows on a circuit-by-circuit, substation-by-substation basis (6T 3370), and “[l]oad growth, that is, circuit overloading, is indeed a good reason to convert a 4.8kV or 8.2kV [sic, 8.3kV] circuit to 13.2kV; in fact, in my opinion, it is one of the only valid reasons to convert” (6T 3373). Company witness Deol discussed examples of projects where load growth is one of the factors for conversion (2T 29-30). Mr. Deol also provided examples other than loading of valid drivers for the 4.8CC projects (2T 28).⁵⁰

There are three additional concerns with Mr. Stephens’ testimony in this area. First, the Company consistently identifies the reduction of wire downs as a key safety benefit. Mr. Stephens did not address safety relating to conversion projects. Mr. Stephens’ use of OSHA recordable incidents as a metric in other categories of investments is also improper as discussed above (Deol, 2T 30-31).

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

Third, Mr. Stephens incorrectly asserted that “the reliability of DTE’s 4.8 and 8.2kV [sic, 8.3 kV] circuits is significantly better than the Company’s 13.2kV circuits, as the Table 1 below

⁵⁰ A CC (conversion/consolidation) project could convert an area to higher voltage or consolidate underutilized assets, and in some cases could decommission equipment no longer carrying load (Deol, 2T 258).

indicates” (6T 3376). Mr. Stephens’s assertion is incorrect, and it is unclear how he derived the values in his table (Deol, 2T 264-65). Mr. Stephens’s calculation was based on an average of the 4.8kV/8.3kV and 13.2kV circuit level SAIDI ex-MEDs. SAIDI ex-MEDs are calculated as customer minutes of interruption on a circuit (excluding MEDs) divided by customers on a circuit (See Exhibit A-47, page 4). As each circuit has a different number of customers (denominator), the calculation Mr. Stephens performed is mathematically incorrect; fractions cannot be averaged together with different denominators. The correct calculation should have been made by adding all the customer minutes of interruption for each system divided by the total number of customers each system serves. As such, any conclusions or implications Mr. Stephens has made using his reliability calculations have no merit and should be discarded. Additionally, the Company provided a comparison of 4.8kV and 13.2kV system reliability in the March 22, 2023 Technical Conference (See Ex MEC-81 page 7).

In summary, Mr. Stephens’ proposed 50% disallowance lacks any valid evidentiary basis. The record further reflects that the 4.8kV/8.3kV conversion projects will improve safety and reliability for customers and are otherwise reasonable and prudent. Therefore, cost recovery should be fully approved.

3. CODI.

This program converts some of the oldest sections of the Company’s grid from 4.8kV to 13.2kV through cable replacements, breaker replacements, and other work to address aging infrastructure. This program is needed to address the significant portions of the electrical infrastructure in the downtown area of the City of Detroit including healthcare facilities, stadiums, and universities, which were placed in service in the early part of the 20th century. Redevelopment in the City of Detroit is stressing this aging infrastructure, and the Company cannot serve new

customer load with existing capacity. The Company is focusing on ten CODI projects between 2021 and 2024, as shown on Table 4 at Deol, 2T 211-12 (Deol, 2T 208-13, 268-71; see also Exhibit A-23, Schedule M5 and M7).⁵¹

AG/MNSC witness Stephens asserted, “As with the 4.8kV and 8.2kV [sic, 8.3kV] conversion programs, I recommend spending going forward be cut by 50%, thus spreading the program out over a longer time period, at least until improvements to distribution planning in Michigan such as those recommended by AG-MNSC Witness Alvarez can be developed and put to work” (6T 3378), reasoning: “As with 4.8kV conversions generally, load growth, that is overloading, is a reason to convert, although I do not recommend buying into the Company’s claims that loads are growing wholesale, or that capacity ratings are accurately stated. Circuit- and substation-specific load growth forecasts relative to nameplate (not assessed or subjectively determined) substation capacity ratings should be required before any specific projects are authorized by the Commission” (6T 3377).

The Company disagrees with Mr. Stephen’s assessment, and again asserts it does not subjectively rate substations. The Company rates substation capacity similar to Mr. Stephens, except the Company prudently plans for contingency (Deol, 2T 229). There is also no basis for his comment that the Company “claims that loads are growing wholesale.” The Company provided a purpose and necessity for each CODI project in Exhibit A-23, Schedule M5. Through discovery,

⁵¹ Approximately 14% of the Company’s customers are in the city of Detroit, but the Company is investing over 30% of its 2022-2024 strategic capital in the city. These projects address aging infrastructure and improve safety and reliability of the distribution system. The CODI and conversion projects in this case will convert the system serving more than 50,000 residential Detroit customers from 4.8kV to 13.2kV (Deol, 2T 213).

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

the Company also provided the circuit capacity, historic loading, and forecasting loading for each CODI circuit (Exhibit A-41, Schedule FF4) and additional load-growth information (Exhibit A-41, Schedule FF6). Mr. Stephens also acknowledged that: “All infrastructure must be replaced over time, and capacity must be upgraded over time as load grows on a circuit-by-circuit, substation-by-substation basis.” (6T 3370). As the record demonstrates, now is the time to replace the aging CODI assets. Moreover, Mr. Stephens did not analyze the reasonableness and prudence of any CODI project or its corresponding investment. He simply recommended an across-the-board disallowance based on unfounded and disproven assertions. Because Mr. Stephen’s claims lack a sound evidentiary basis, among other reasons, the Commission should reject them. (Deol, 2T 267-71).

Staff proposed disallowances of \$56.4 million for the 11 months ending November 30, 2023, and \$115.9 million for the projected test year based on a historical calculation, essentially using the 8% increase in CODI spending from 2021 to 2022 as the basis for a 10% annual escalation rate that Staff applied to 2022 costs to get projected 2023 and 2024 costs (Shi, 7T 4697). The Company understands Staff’s concerns regarding historic investment levels being lower than projected levels, but the historic numbers do not tell the whole story. The 2021 and 2022 CODI investments were primarily for building and upgrading substations. Now that this work is complete, the investments for 2023 and 2024 will focus on overhead (OH) and underground conversions, which will require more construction work and be more capital-intensive. The Company has also increased its resources to complete the increased level of work. For example, regarding OH conversion work, the Company has increased its OH workforce from 293 to 659 average daily by month contractors. Additionally, the Company has created a focused Project Management Organization (PMO) to manage and ensure project execution. The Company contends that Staff’s

concerns have been addressed, and Staff's reliance on historic costs is misplaced in light of the evidence showing that the investments are necessary, reasonably and prudently planned and supported, and will benefit customers. Therefore, the Company's requested recovery for CODI investments should be fully approved. (Deol, 2T 273-75; Miller, 5T 2851-53).

4. Strategic Undergrounding (SUG) Program.

The Company's strategic undergrounding pilots seek to understand the viability of undergrounding in different technical scenarios to address grid resiliency challenges. In Case No. U-20836, Staff proposed disallowances⁵² reasoning that "capital expenditures for new undergrounding pilots should not be put into rates until the Appoline DC 1346 pilot is completed, and the results known and analyzed" (Case No. U-20836, 8T 5430, dk#754). The Commission agreed that this was reasonable and prudent "until the Appoline pilot is complete and a full report is available, and until a more robust analysis of the benefit/cost of strategic undergrounding is available" (November 18, 2022 Order in Case No. U-20836, pp 111-12).

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

The Company further proposes a second pilot, Fairmont DC 1593, which would differ from the Appoline pilot by relocating rear-lot overhead assets to front-lot URD in a two-block area served by Fairmount DC 1593 in Detroit. The Company has leveraged lessons learned from the Appoline

⁵² These disallowances included \$15,100,000 of \$17,248,000 for the ten months ending October 31, 2022 and the entire \$36,783,000 for the test year. Case No. U-20836, 8T 5430, dk #754.

pilot, and when the Fairmount pilot is done, the Company will have a more larger data set to perform a benefit-cost analysis for undergrounding projects (Deol, 2T 225-27).

Staff recommended “a full disallowance of the \$1,925,000 projected for the 11 months ending 11/30/2023 and \$1,917,000 projected for the test year” (Evans, 7T 4415), reasoning that the Company did not comply with the U-20836 Order because “neither Mr. Deol’s testimony nor any exhibits provide a benefit/cost analysis of the proposed Fairmount pilot, so the Company cannot and does not compare it to the benefit/cost analysis of other solutions, such as grid hardening, grid conversion, or tree trimming” (Evans, 7T 4414). AG witness Coppola similarly proposed a disallowance for the Fairmount pilot, asserting that “the Company has not made a compelling and convincing case that another strategic undergrounding pilot is needed at this time to prepare a cost/benefit analysis of comparable solutions” (Coppola, 6T 3688).

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

Staff further proposed that “[d]ue to the number of down service drops that occurred in the late February and early March 2023 storms, Staff recommends that the Company provide a cost-benefit analysis of undergrounding residential service drops in its next rate case. Reliability

improvements should be one of the benefits discussed, and the methodology for calculating, estimating, or measuring such benefits should be described in the analysis.” (Evans, 7T 4415).

The Company does not have enough information to complete the suggested analysis at this time. As indicated above, the Commission denied an undergrounding pilot in Case No. U-20836, and the Company now proposes a second pilot that Staff opposes. Until the Company attempts to execute undergrounding work at scale and in different locations, it cannot provide a robust cost-benefit analysis. Therefore, Staff’s proposal for an analysis of undergrounding service drops alone should not be adopted, however, the Company is willing to have discussions with Staff regarding the potential for proposing another undergrounding pilot. (Deol, 2T 284)

5. Primary Deconductoring.

Primary Deconductoring includes the removal of underutilized infrastructure such as small-sized primary wire, arc wire, overhead (OH) transformers, and other pole top equipment. 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 a pilot involving projects on two circuits, and is presently performing deconductoring in the 4.8kV Hardening program. The Company will also consider deconductoring where appropriate in the 4.8vV Conversion program, and whether a standalone Primary Deconductoring program is needed. (Deol, 2T 227-28)

6. System Loading.

System overloads occur when there is not enough capacity to meet customer demands and still maintain equipment operating ratings. 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, 2T 228-32, 277-78).

AG/MNSC witness Stephens proposed a 50% disallowance (6T 3384), after discussing System Loading collectively with Substation Redesign and Rebuild (6T 3379-84). The Company incorporates its discussions above regarding preliminary matters and Substation Redesign and Rebuild, explaining that Mr. Stephens misused the EV “loading workpapers” and failed to address that the Company subjectively determined and de-rated its substations. The Company’s substation capacity ratings are based on equipment ratings, and the Company must consider contingency when planning. The Company also provided the overloads being addressed for each project (Exhibit A-23, Schedule M5, pp 418-501). Mr. Stephens also did not address the specific purpose, necessity, reasonableness, prudence, or investment for any specific project. Instead, he simply proposed an across-the-board disallowance. Mr. Stephens’ proposal should be rejected, and full cost recovery for the Company’s investments should be approved. (Deol, 2T 277-79).

c. Technology & Automation.

Technology & Automation projects and programs are tightly linked to the grid modernization and include investments that develop capabilities in grid observability, analytics and computing, controls, and communications. They meet current grid needs and provide immediate benefits to customers. They also lay the foundation for grid modernization and are necessary to support increased adoption of distributed energy resources (DERs) and electric vehicles (EVs). See

Exhibit A-12, Schedule B5.4, p 12; Exhibit A-23, Schedule M6; (Hill, 5T 2766. Significant investments include 4.8kV Circuit Automation, Grid Automation Telecommunications, Distribution Automation, Non-Wires Alternatives (NWA) pilots, and Conservation Voltage Reduction (CVR)/Volt-Var Optimization (VVO), as discussed below.

1. 4.8kV Circuit Automation.

The 4.8kV Circuit Automation project will install remote-operating reclosers at, or as close as possible to, the beginning of 4.8kV circuits. This project will address safety and reliability issues with the 4.8kV system. When the system operation center (SOC) receives an alarm that a wire is down, the SOC will be able to remotely isolate the ground beyond the recloser. This will enable the Company to mobilize crews faster to downed wires and reduce customer outage times. The Company plans to install remote-operating reclosers on all 4.8kV circuits, except for circuits that are scheduled for conversion over the next five years, and those having existing SCADA technology. (Hill, 5T 2767-69).

2. Grid Automation Telecommunications.

Robust and secure communications channels are foundational for a modern and advanced grid. Telecommunications is so critical that the Department of Energy has included it as a foundational infrastructure investment in their Modern Distribution Grid report which is known in the industry as the DSPx. Participants in the development of the DSPx included public regulators, utilities and industry experts such as IEEE, EPRI, and EEI. The Company's Subject Matter Experts (SME's) are following these industry guidelines in developing and deploying grid telecommunications investments (Exhibit A-38, Schedule CC2). Many devices on DTE Electric's system, however, are either not connected for remote monitoring and control, or are connected

through a communication network that is not fully integrated. The Grid Automation Telecommunications program includes installation of a more modern telecommunications system with sufficient bandwidth to support all anticipated usage and growth discussed in the Company's DGP, providing improved reliability and increased cybersecurity for a modern electrical system. (Hill, 5T 2769-74).

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

The Company disagrees with Mr. Stephens because it presented ample evidence supporting the need for these telecommunications upgrades. The Company's SMEs have also performed extensive analysis on the use of fiber optic versus wireless communications options and demonstrated the value of the upgrade. (Hill, 5T 2801, 2806; Exhibit A-38, Schedules CC1 and CC2).

Wireless carriers do not offer full coverage for data across portions of the Company's service territory and have different levels of service quality and bandwidth inside the areas that they do serve. Wireless carriers also typically have a cost to build out their network infrastructure, so the Company would have to pay an upfront cost for network extension, and then continue to pay costs for leased services. (Hill, 5T 2802).

Even when wireless service is available, it is not as reliable as fiber optic cable because wireless communications are subject to dead zones or poor reception inside of buildings. Wireless

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

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

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

Mr. Stephens' indication that wireless is good enough for police and fire departments, and by extension it is "good enough" for the Company, neglects that police and fire departments have

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

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

3. Distribution Automation, including Substation Automation.

DTE Electric's efforts on Distribution Automation⁵³ have unfolded over the past several years. Today, roughly 32% of general-purpose substations and 25% of the distribution circuits in DTE Electric's territory have SCADA monitoring and control. Approximately 5% of the distribution circuits have automatic loop schemes, which can automatically transfer sections of the circuits onto adjacent circuits when an outage is detected. The Company is strategically implementing Distribution Automation to maximize customer benefits. The scope of work for 2022 included the design of full SCADA control and monitoring of one substation and development of standards and processes that can be utilized to accelerate the installation of distribution automation

⁵³ The Department of Energy (DOE) report "Distribution Automation: Results from the Smart Grid Investment Program," published in September of 2016, states: "Distribution Automation (DA) uses digital sensors and switches with advanced control and communication technologies to automate feeder switching, voltage and equipment health monitoring; and outage, voltage and reactive power management. Automation can improve the speed, cost, accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers" (Hill, 5T 2774).

equipment across the electrical system. These new standards will be applied in 2023 and 2024 to upgrade substations and rebuild circuits. (Hill, 5T 2774-77).

Substation automation involves control panel replacements with upgraded, standardized relays, installation of Remote Terminal Units (RTU), incorporation of the RTUs and automation controls into the same substation network, and breaker replacements as needed. The automation technologies installed on substations will also be linked to the ADMS for enhanced applications. (Hill, 5T 2776). AG witness Coppola proposed that the Commission “remove a total amount of \$27,916,000 from the Company’s forecasted capital expenditures with \$4,583,000 (\$5,000,000 x 11/12) for the 11 months ending November 2023, and \$23,333,000 for the 12 months ending November 2024 (45), suggesting that it is “not possible . . . to connect work to be performed in 2023 and 2024 to the \$30 million forecasted to be spent in those two years” (Coppola, 6T 3656).

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

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

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

The Company has supported its funding request, including how and when the funds will be used, and benefits to customers. This demonstrates that the investments are reasonable and prudent, and should be approved.

4. Non-Wires Alternatives (NWA) Pilots.

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

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

The Commission further advised that it “expects to be presented with ‘a robust suite of NWAs that may be evaluated for prudence 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 to address circuit or substation overload concerns to help delay or offset traditional grid upgrades. The Commission’s November 18, 2022 Order in Case No. U-20836 provided feedback on each pilot (summarized in Exhibit A-12, Schedule B5.4.9, with the Company’s response)

There are nine NWA pilots as shown in Table 5 of Mr. Hill’s direct testimony (at 5T 2781). This includes the first NWA pilot at Hancock substation (which was completed as discussed in Case No. U-20836), and the remaining pilots as described in Exhibit A-12, Schedules B5.4.1 to 5.4.7;

Exhibit A-23, Schedule M6; Exhibit A-23, Schedule M7 (DGP, section 12.7, starting at page 400)). The pilots the Company are currently pursuing are building blocks, which will form a foundation for future NWA projects. (Hill, 5T 2779-80).

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

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

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

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

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

Turning to the specific pilots, the 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. In response to Staff’s concerns expressed in Case No. U-20836, the Company provided more detailed support for labor costs, and an update on progress that has been made on the pilot (Hill, 5T 2782-83; Exhibit A-12, Schedule B5.4.1, pp. 2-3; Exhibit A-12, Schedule B5.4.9, p 1). No further issues were raised by Staff in this case.

Mr. Coppola proposed a \$2,513,000 disallowance based on his views about Alternatives, Scalability, and Guidelines, and the further contention that the Company has not stated lessons learned (6T 3670). The Company disagrees, incorporating the discussion above, and further noting that lessons learned are included in Exhibit A-12, Schedule B5.4.1, section 1, subpart b, and alternatives considered for this pilot are in Exhibit A-12, Schedule B5.4.1, section 3, subpart c (Hill, 5T 2813).

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

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

The Omega Load Relief pilot involves placing mobile storage equipment (the same equipment described above for the Mobile Battery Trailer pilot) at the Omega substation. The substation is fed by two subtransmission lines that are both overloaded. Projects to address these conditions will require shutdowns and contingency plans to mitigate the risk of long-duration and wide-scale outages. The equipment will facilitate the shutdowns and contingency plans. The Company has provided detailed support for labor costs, and an update on progress that has been made on the pilot. (Hill, 5T 2784-86; Exhibit A-12, Schedule B5.4.3, pp. 2-3; Exhibit A-12, Schedule B5.4.9, p 2).

Mr. Coppola proposed an \$8,442,000 disallowance based on his views regarding Alternatives, Scalability, and Guidelines (6T 3673-74). The Company disagrees, incorporating the discussion above, and further noting that it evaluated and compared the pilot against possible alternatives presented in Exhibit A-12, Schedule B5.4.3, section 3, subpart c (Hill, 5T 2815).

Mr. Coppola further asserted that “[a] temporary solution at a cost of \$8.4 million that provides only 4 hours of back-up power at full draw seems to be an excessive cost for the limited use” (6T 3673). The Company disagrees because the use of this technology at peak load times, even for durations less than 4 hours, is critical to preventing overloads that cause equipment failures resulting in customer outages. This flexible solution is also a viable reliability option that can be deployed elsewhere while the Company converts to higher voltage. The use of battery trailers can provide enormous benefits to the Company’s customers through reduced and eliminated power outages (Hill, 5T 2815).

The Fisher Load Relief pilot includes geo-targeted deployment of Demand Response (DR) and Energy Waste Reduction (EWR) to relieve a portion of the load concerns at the Fisher substation (Hill, 5T 2786-87; Exhibit A-12 Schedule B5.4.4). The Company provided detailed support and an update on progress that has been made on the pilot (Hill, 5T 2786-89; Exhibit A-12, Schedule B5.4.4 and Schedule B5.4.9, p 2). No party proposed a disallowance for this pilot.

The Port Austin Load Relief pilot involves solar and storage to address concerns with the Port Austin substation being above its firm rating. The Company has provided detailed support, and an update on progress that has been made on the pilot (Hill, 5T 2789-90; Exhibit A-12, Schedule B5.4.5; Exhibit A-12, Schedule B5.4.9, p 3).

The Company is also exploring opportunities for federal funding from the Infrastructure Investment and Jobs Act (IIJA) to expand NWA deployments at O’Shea and Port Austin by incorporating innovative new technologies like adaptive networked microgrids to increase customer benefits from the deployed assets (Hill, 5T 2794-95; see also Kryscynski, 3T 396-99, regarding future opportunities for IIJA grants to fund infrastructure investments).

Mr. Coppola proposed a \$5,591,000 disallowance, stating that “[a]lthough on the surface it would appear that the microgrid solution at \$5.7 million would be a better economic solution, the Company has stated that it eventually needs to proceed with the conversion to the 13.2kV system and will need to spend the additional \$15 million. Therefore, the microgrid cost is an additional cost *above* the \$15 million that eventually needs to be incurred” (6T 3675). The AG’s focus on only long-term costs neglects to consider that the project is necessary to provide *immediate* relief for existing substation overloads (Hill, 5T 2789). The project also addresses reliability and resiliency needs of customers at the most distant part of the Company’s distribution system, including an area that has experienced two tornados in recent years. The overloads alone have the potential to leave customers without power in the event of a substation failure. The longer-term solution would not take place soon enough to mitigate this immediate risk. The NWA solution mitigates the risk, which enables the Company to defer the more costly conversion to a later date (Hill, 5T 2816).

The Veridian pilot has three aspects (Underground Residential Distribution (URD) Loop; System Upgrades; and Microgrid) to accommodate load growth for the Veridian all-electric residential development in Ann Arbor. The Commission previously approved cost recovery but indicated that it would continue to monitor costs as the project proceeds and additional details are available (Case No. U-20836 Order dated November 18, 2022, p. 156). The Company has provided details, and an update on progress that has been made on the pilot (Hill, 5T 2790-92; Exhibit A-12, Schedule B5.4.6; Exhibit A-12, Schedule B5.4.9, p 4).

Mr. Coppola proposed a \$7,935,000 disallowance, indicating doubts about the need for system upgrades (6T 3677-79). On the contrary, there is a very real need for the system upgrade. Although the Regent substation itself is not currently overloaded, the specific circuits feeding the Veridian development cannot support the requested service. Also, although the solar and storage

assets paid for by the developer will offset the development's electric demand, the Company must be able to provide service in the event of low to nonexistent solar generation or storage availability. The larger wires also provide voltage support in the event of high solar output, where customer generation supplies energy to the grid.⁵⁴ The system upgrades also do not benefit only the Verizon development, because all customers on each upgraded Regent circuit will experience a reliability improvement via upgraded poles, wires, and associated equipment. The work will also prepare the area for future conversion to 13.2kV by pre-converting the area to current design standards. Thus, the circuit upgrades (\$4.3 million of the Veridian pilot investment) are not only necessary for the Veridian pilot, but also for the Regent area conversion (Hill, 5T 2817).

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

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

The EV Charging Demonstration at ACM (American Center for Mobility) concerns the Company's support for implementing the Delta Power Electronics DC Xtreme 400KV fast charger

⁵⁴ The same response generally applies to Mr. Coppola's assertions that these customers would be "electric power self-sufficient with only temporary use of power from the electric grid. Therefore, any additional power draw from the substation should be limited and intermittent" (6T 3677). These generalized assertions lack support and do not consider the impact of the load under various scenarios, such as reverse power flow from the customer DER, low state of charge of customer-owned storage, and solar availability. The assertions also do not indicate any consideration for the need for controls to coordinate the resources. (Hill, 5T 2818-19).

and understanding the impacts of high-powered charging on power quality. The Company has provided detailed information and an update on progress that has been made on the pilot, (Hill, 5T 2792-94; Exhibit A-12, Schedule B5.4.7).

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

The Company disagrees with this disallowance because the Company provided significant evidence showing how the funding will be invested, and how the investment will benefit the Company and its customers. (Hill, 5T 2792-94, 2820; Exhibit A-12, Schedule B5.4.7; Exhibit A-23, Schedule M6, pp 71-74; Exhibit A-23, Schedule M7, pp 415-416; Exhibit A-38, Schedule CC3). In summary, the ACM is a multi-partner facility to test the grid component needed to support DC fast charging, autonomous vehicles, and other mobile technology. Specific investments include a utility gateway and communications portal to enable charge management, a control algorithm for the Delta Extreme fast charger, cyber security interfaces and controls, sensing and monitoring devices, and monitoring and control algorithms for in-road inductive charging. Benefits of the investment include learning about the technology that will be needed in the future for electrification, while being supported by DOE funding. Specific benefits include the development of the delta charging hardware that provides extreme fast charging capabilities, and a solid-state transformer technology that allows direct connection of these high-power chargers to distribution lines. (Hill, 5T 2821).

Staff made four recommendations for NWA pilots. (Matthews, 7T 4568-70). The Company agrees with Staff’s recommendation that the Company meet with Staff prior to implementing future

NWA pilots and at a set frequency through the pilot's term. The Company is open to discussions with Staff to understand the full intent of the other three (mobile battery) recommendations. As indicated above, the Company is looking at mobile battery pilots to support a variety of potential grid needs. There is no need for a directive from the Commission (Hill, 5T 2822-23).

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

5. 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-20471.⁵⁵ The Company continues to implement and evaluate CVR/VVO because it is a reasonable and prudent cost-effective way to offset peak generation. The Company installed CVR/VVO on two substation transformers and 12 circuits in 2022, and has identified 14 substation transformer locations and 93 circuit locations for 2024 (the Company temporarily halted the program in 2023 to ramp up the 4.8kV Circuit Automation program). The Commission previously adopted Staff's proposed disallowance for 2023, and sought additional information (Case No. U-

⁵⁵ VVO manages system-wide voltage levels and reactive power flow to achieve one or more specific operating objectives, which can include reducing losses, managing voltage volatility due to intermittent renewable generation, optimizing operating parameters, and/or optimizing power factors. CVR, as one of the VVO options, is designed to maintain customer voltage levels in the lower portion of the allowable voltage ranges, thus reducing system losses, peak demand, or energy consumption (Hill, 5T 2795).

20836 Order dated November 18, 2022, p. 143). Additional yearly data and details on CVR/VVO benefits are provided in the IRP Annual report that the Company files in April in Case No. U-20471. The Company's most recent IRP case (U-21193) provided forecasted benefits of the CVR/VVO programs (Hill, 5T 2795-96).

6. Distributed Energy Resources Management System (DERMS).

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

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

7. Work Management and Scheduling.

AG witness Coppola proposed that the Commission “remove \$16,281,000 from the Company’s forecasted capital expenditures with \$6,160,000 from 2022, \$6,736,000 from the 11 months ending November 2023, and \$3,385,000 from the 12 months ending November 2024,” stating that “[i]t appears that no Company witness filed testimony justifying the business reasons for the project,” and “[f]rom the brief information provided, it is not possible to establish the need to undertake the upgrades and whether they are justified” (6T 3682-83).

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

8. Load Forecasting and Analytics.

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

The Company disagrees because the business reason for the project is stated on page 435 of Exhibit A-23, Schedule M7 DGP. Additional detail is provided by Exhibit A-23, Schedule M7, section 4.2 Forecasting, beginning on page 65. After quoting the business reason, Company witness Hill further quoted Exhibit A-23, Schedule M7 DGP, pages 435-36, which explains why the Company's current load forecasting system cannot handle new forecasting needs. The project is reasonable, prudent, and supported, so cost recovery should be approved (Hill, 5T 2829-30).

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

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

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

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

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

The Company now seeks recovery of \$1.292 million for 2021; \$3.986 million for the 23-month bridge period ending November 30, 2023; and \$2.9 million for the projected test year (Reterstorf, 5T 2913; Exhibit A-12, Schedule B5.4, page 12, line 3). Ms. Reterstorf provided the current status of implementing the NMS investments in the each of four focus areas and explained that investments to date have improved the Company’s operational ability to generate maps from

GIS, improved the Company's load analysis ability, and enabled more accurate preventative maintenance planning. Combined with the remaining work in 2023, this investment will continue to improve data quality as reflected by specific metrics in each focus area (Reterstorf, 5T 2913-16).

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

The Company disagrees with the AG because the additional NMS investment provides benefits of more accurate load and planning analysis, improved responsiveness to customer adoption of new technologies such as DERs and EVs, improved reliability, and improved preventative maintenance processes. These benefits demonstrate that the costs are reasonable and prudent (Reterstorf, 5T 2909-12, 2944).

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

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

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

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

Based on the Company's successful prior implementations with OSI and the vendor's experience in the utility industry, DTE Electric originally made the decision to proceed with the DMS/OMS implementations without a system integrator. DTE Electric worked successfully with OSI during 2018 and 2019 to implement the GMS and EMS on budget and ahead of schedule

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

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

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

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

DTEE has launched ADMS including the early success with EMS, GMS, and NMS and the February 2023 launch of OMS and DMS, which included the complex integration of other customer and workforce systems. DTE Electric exercised caution and diligence in designing and launching the OMS and DMS project given its critical importance to the Company's operations. The Company acted responsibly in its project management and oversight of the vendor, including the negotiation of remedies to limit costs borne by ratepayers. And in response to the Commission's questions in Case No. U-20836 regarding the timing of the System Integrator, my testimony reinforces the prudence of DTE Electric's timing and approach to engage the System Integrator in mid-2020 to support the OMS and DMS implementation following the launch of EMS and GMS on budget and ahead of schedule. Upon initial indications that the System Integrator would be needed, DTE Electric moved quickly to engage the System Integrator to guide the project. DTE Electric's established project oversight processes allowed for such timely decision-making and actions to mitigate additional risks.

Throughout this process, DTE Electric prioritized the quality and integrity of the new ADMS system, including extensive pre-launch testing and system integration efforts to replace a large number of legacy systems. Guided by the System Integrator who was enlisted early in the OMS and DMS project, DTE Electric made the correct decisions to avoid a premature system deployment that could have harmed reliability, work management processes, or customer service. [Reterstorf, 5T 2931-32.]

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

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

The Company believes that Mr. Coppola's characterization of the factors that influenced the delays and cost overruns is inaccurate. Instead, the COVID-19 pandemic, delay of the next version of the

Compass mobile tool and maintaining the improvements in customer outage communications were the primary drivers (Reterstorf, 5T 2921-23, 2937-38).

Mr. Coppola also recounted his testimony from Case No. U-20162 criticizing new technology (6T 3655), but the ALJ in that case noted that the ADMS projects will help address systems “that have reached end-of-life” (Case No. U-20162, PFD, p. 83). The Commission adopted the ALJ’s findings, further noting that “Simply because technology is new does not mean that it should be ignored, or that it will not provide a benefit to ratepayers” (Case No. U-20162 Order dated May 2, 2019, p. 28).

Mr. Coppola’s continuing criticism of the project as “premature” also neglects to consider that the OMS had reached its end-of-life and needed to be replaced, a fact he does not dispute. The Company therefore was faced with two options: (1) replace the end-of-life OMS as part of the ADMS project, or (2) implement a stand-alone OMS that was not part of a larger ADMS platform. The second option would have been more costly to customers and otherwise imprudent, so the Company did not pursue it. Nor does Mr. Coppola argue that this option would have any benefits. He simply continues to criticize the Company for pursuing what was effectively the only viable option (Reterstorf, 5T 2939).

Mr. Coppola also criticized the Company for selecting OSI as the vendor, implying (without support) that OSI might be unsuccessful in implementing systems (Coppola, 6T 3655). To the contrary, OSI has successfully implemented ADMS at numerous utilities. (Retersdorf, 5T 2941-42). The Company’s ADMS implementation also met the project’s success criteria and proved itself less than one month into implementation when the Company experienced one of the largest catastrophic storms in its history. The new ADMS implementation performed beyond expected

service levels under the extreme outage load. OSI considers DTE's overall implementation to be a benchmark for utilities implementing the platform (Reterstorf, 5T 2941).

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

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

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

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

proposed capital expenditures to complete the ESOC project to meet NERC certification requirements” (Case No. U-20836 Order dated November 18, 2022, p. 137).

The Company now requests approximately \$1.6 million for investments in 2022 and 2023, which are primarily used to support the development of the IT systems supporting the ESOC. Construction of the ESOC is complete, all personnel have moved into the new facility for day-to-day operations, and the record reflects numerous examples of expected benefits being realized. The Company acknowledges the Commission’s indicated expectation that there would be no further capital investment in the ESOC, but it is a critical operational resource that will require incremental investments to maintain and evolve to meet future needs (Elliott Andahazy, 3T 553-57; Exhibit A-12, Schedule B5.4, page 12, line 4).

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

Both the ESOC and ASOC facilities are well justified and should be fully funded. Due to the essential nature of the ESOC in operating the electric grid, a backup facility is required in the

event the primary facility is inoperable, and the ASOC's location (approximately 25 miles from the new ESOC) will allow the Company to safely operate the grid in the case of a major adverse event at the ESOC (Elliott Andahazy, 3T 557-58). Customers will benefit in numerous ways from the SOC Modernization project, as Ms. Elliott Andahazy testified:

Customers will benefit from the improved communications paths between resources that will be co-located in the new facilities, which will facilitate quicker and improved coordination to create and implement restoration strategies more efficiently. Plus, customers will benefit from reduced risk in disruption in operations during outage events, and faster restoration times regardless of the facility from which the System Operations organization is forced to operate. The ability to understand system conditions and dispatch resources to address issues will be greatly enhanced by the technology available in the new facilities and the co-location of the system Operators, Power Dispatchers, and support personnel. In addition, ESOC is more resilient and hardened to withstand adverse natural and man-made disasters, allowing electric grid operations to recover much more quickly in the event of a major catastrophe. These benefits have already started to materialize due to the utilization of the ESOC, as discussed earlier in my testimony, and will be fully realized once the ASOC is complete. [Elliott Andahazy, 3T 560.]

AG witness Coppola proposed that, for the ESOC, "additional costs of \$2,048,000 above the previously approved amount of \$98.5 million should not be included in rate base" and recommended that the Commission "remove \$428,000 for 2021, \$1,420,000 for 2022, and \$200,000 for 2023 from the Company's proposed capital expenditures" (6T 3662). It appears that Mr. Coppola only calculated that the amount requested exceeds the amount that was approved, so therefore any additional amount should be disallowed. This is an oversimplification, and the Company disagrees.

Based on the Commission's direction in Case No. U-20836, the Company investigated methods to keep the investment at \$98.5 million. However, the Company was unable to properly operate the ESOC without the additional investments to support the development of the IT systems supporting the ESOC as a whole, and the new ADMS. The Company made these additional reasonable and prudent investments in good faith, as were necessary to operate the ESOC as

intended. Because this additional investment was reasonably and prudently spent, its cost recovery should be approved (Elliott Andahazy, 3T 553, 605-606).⁵⁶

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

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

xi. Advanced Metering Infrastructure (AMI)

Advanced Metering Infrastructure (AMI) meters (also known as smart meters) increase reliability, reduce outage time, and provide other benefits as compared to obsolete

⁵⁶ Mr. Coppola further suggested that the Company just presented a “rundown of activities” that were performed during events, rather than a showing of the ESOC’s benefits (Coppola, 6T 3662). This is false. The Company presented examples of the benefits that it was able to obtain due to the ESOC during specific events. These benefits included improved communication and collaboration, response times to coordinate field resources required, and faster decision-making that reduced unneeded field resources being sent to specific locations. (Elliot Andahazy, 3T 555-57, 606).

electromechanical (analog) meters. AMI meters are automatically read, monitored and controlled, instead of relying on manual actions (such as meter readers).⁵⁷ As of December 31, 2019, the Company's AMI program is considered fully implemented. Analog meters remain only at sites where the Company has no access, and the Company continues to support the ability of customers to opt-out as long as they pay the extra costs of manual reading so that other customers do not have to subsidize those costs (Reterstorf, 5T 2894).⁵⁸

Company witness Ms. Reterstorf discussed AMI's core benefits to utility customers (5T 2894-95), and how DTE Electric is also leveraging AMI technology to enhance customer benefits and improve service quality in new ways (5T 2895-98).

Ms. Reterstorf supported \$2.156 million of capital investments (\$1.53 million in 2021; \$626,000 for the 2022 bridge period) for AMI: Meter Communications Upgrade. This investment was required due to public cellular wireless carriers phasing out 3G⁵⁹ service so all meters previously deployed using 3G technology would no longer be capable of remote communications. The Company purchased and installed 5,029 4G-enabled meters in 2021 and 2022 to complete the necessary meter replacements for large commercial customers. This effort concluded the required

⁵⁷ The Commission reviewed DTE Electric's AMI program and approved incremental funding for the Company's AMI investments in successive general rate cases, beginning with the December 23, 2008 Order in Case U-15244, p 62, which was not appealed. More recently, the Commission has declined to revisit the AMI issues and arguments that it thoroughly reviewed and addressed in past cases, and the Court of Appeals has affirmed. December 11, 2015 Order in Case No. U-17767, p 34, aff'd *In re Application of DTE Electric Company to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued February 13, 2018 (Docket Nos. 331599, 331868, and 332159); January 31, 2017 Order in Case No. U-18014, p 129, aff'd *In re Application of DTE Electric Company to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued October 25, 2018 (Docket No. 338378).

⁵⁸ See Case No. U-20837. The Commission originally approved the cost-based rates for DTE Electric's opt-out program in Case No. U-17053. The Court of Appeals affirmed, and the Supreme Court declined to grant leave or to reconsider that denial. *Application of Detroit Edison to Implement Opt-Out Program*, unpublished opinion per curiam of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728 and 316781), *lv den* 499 Mich 868 (2016), *recon den* 499 Mich 972 (2016).

⁵⁹ 3G is the third generation of cellular telecommunications technology, which is being succeeded by 4G (and by 5G in some instances).

3G-to-4G technology upgrade (5T 2898-99; Exhibit A-12, Schedule B5.4, page 12, line 30). No party disputed full recovery of these costs.

5. Community Lighting

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

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

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

Turning to wattage selection, Mr. Bellini further explained that it is important to select the appropriate luminaire because the purpose of street lighting is to provide adequate light levels,

uniformity, and target contrast depending on the road classification. To ensure that luminaire output for new (not existing) roadway installations, achieves the proper level of illumination, the Company performs an in-depth photometric evaluation based on the effectiveness of a roadway luminaire achieving pre-established, application-based photometric requirements. The outcome determines whether a new LED luminaire can achieve minimum roadway luminance and illuminance target values that comply with ANSI/IES RP-8 standards (Bellini, 5T 2633-35).⁶⁰

MI-MAUI witness Bunch asserted both that the Company spends too much on LED luminaires and that the Company “claims to” observe ANSI/IES RP-8 standards, but “in practice it does not” based on an incorrect application of a vendor marketing and sales chart (4T 915). The criticism improperly conflates the evaluation process for new installations (where Mr. Bunch apparently has no issue) with the process for conversions of HID’s to LED’s on existing roadways. Witness Bunch also incorrectly asserted that “the Company assumes, without basis, that the current lights meet today’s ANSI/IES RP-8 standard” (4T 916).

The LED luminaires that the Company selects to replace HPS luminaires through its analysis can sometimes deviate from those suggested by a manufacturer, particularly with the Company’s primary luminaire vendor, Leotek, which has published a cross-over chart (Exhibit A-25, Schedule O3) for customers to use as a starting point in evaluating the appropriate LED when converting from an HPS luminaire. The chart’s objective is to match new Leotek LED luminaires with their initial light levels to existing HPS luminaires in the field for several years. In other words, the conversion table is designed to replace a HPS luminaire at its current (degraded) lumen output, not its original lumen output. To replace a HPS luminaire at its degraded lumen output is

⁶⁰ ANSI/IES RP-8 is the benchmark in roadway lighting design practices used in street lighting to evaluate and select new roadway luminaire products (Bellini, 5T 2635).

inappropriate – like replacing old tires with new tires having as little tread as the old tires being replaced. The Company’s objective is to restore equivalent “out of the box” lumen output of the luminaire being replaced to match the intended lighting design of the original streetlighting system (Bellini, 5T 2635-36, 2659-60; Exhibit A-40, Schedule EE4).

Mr. Bunch suggested that the Company should follow Leotek’s HID to LED crossover chart (4T 918). In addition to the discussion above, the Company disagrees with this recommendation because the chart is intended to be used as a starting point in evaluating appropriate luminaire selection. It is closer to a marketing and sales tool rather than authoritative guidance or a technical standard, as reflected by a series of footnotes in the chart (Exhibit A-40, Schedule EEE5). Further, all customers also have the option to deviate from the Company’s recommended LEDs.⁶¹ Municipalities could choose to deviate for various reasons, such as local ordinances, financial considerations, and residents’ feedback. The suggestion that the Leotek chart should be accepted as authoritative guidance would impact municipalities and the Company’s ability to work with them. Not having the ability to propose lighting solutions in a manner that restores converted lights to their original output would also increase the risk for an underlit roadway and set dangerous precedent of essentially forcing the Company to adhere to a de facto standard based on a marketing/sales tool. Therefore, the suggestion that the Company adopt Leoteks crossover chart as authoritative guidance in replacing existing HIDs with LEDs should be rejected (Bellini, 5T 2636, 2660-62).

Mr. Bunch concluded that “DTE has overspent on unnecessarily bright LED luminaires in the amount of \$5,835,192” (4T 919) and recommended that the Commission “reduce DTE’s

⁶¹ For new installations, the customer will acknowledge in their contract that the design does not conform with ANSI/IES RP-8 (Exhibit A-40, Schedule EE6).

required revenue for E1 streetlighting by \$332,524” (4T 920). The Company disagrees because there is no sound basis for these proposals, as discussed above Witness Bunch’s reliance on the Leotek crossover chart is unsound. (Bellini, 5T 2662-63).

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

Mr. Bunch further proposed that the Commission “should order the Company to stop charging CIAC for HID-LED conversions” (4T 914). The Company disagrees for two reasons. First, municipalities who decided to convert their lighting systems to LED and have paid for this conversion would be subsidizing other municipalities’ LED conversions. Second, LED conversions benefit the municipalities that make them. Therefore, the proposal should be rejected. (Bellini, 5T 2657-58).

Witness Bunch also proposes an unjustified and time consuming process to manage outage credits through a streetlight bill credits proposal:(1) begin “tolling 24 hours after the outage is first reported...” but (2) will be provided an exception if the outages are “attributable to the customer”, (3) DTE can then “...apply periodically to recover credits” for root causes beyond its control, (4) but then only “...be allowed recovery for credits related to outages with root causes that are not equipment-based for up to 14 days after the initial report”, unless (5) those outages reported in the previous step are “Beyond 14 days, no recovery of bill credits should be assumed,” but that (6)

“DTE should be able to file an annual report detailing longer-duration outages for which it believes recovery of credits is appropriate.” (4T 936-938).

All of these proposed steps require creation of multiple new reports for which data simply doesn’t exist, nor does Witness Bunch suggest who will be responsible for reviewing and approving such reports. By contrast, should a municipality contact DTE with an outage credit for which the Company is not impeded from making a timely repair, an outage credit is issued generally within the next billing cycle. (5T 2669-2670).

The system proposed by Witness Bunch is unnecessary. First, DTE’s outage performance does not merit such an onerous set of criteria. As shown in Exhibit A-40, Schedule EE3, in 2022, standard duration for outage events was 4.7 days meaning that events on average were completed in less than 5 days from the time they were reported. This is in spite of almost 3,000 events or approximately 17% of reported outages that were either “ok on arrival” (the light was working when the crew arrived or the pole and/or light was damaged by a 3rd party). As such, theoretically, responding to these events created a less efficient restoration process. Second, not all outages are the result of failed Company equipment. (5T 2670). In fact, when the Company is impeded from making a repair, these additional 1,931 “follow-up” events in 2022, added over 2.5 days (over 50%) to the Company’s restoration time for a total of 7.24 days (Exhibit AA-40, Schedule EE3, line 9). Therefore, the Commission should reject MAUI’s streetlight bill credits proposal.

6. Demand Response (DR) Programs and DTE Insight

DTE Electric spent \$9.3 million in capital expenditures for its Demand Response (DR) portfolio in 2022, including the Interruptible Space Conditioning (CoolCurrents), Programmable Controllable Thermostats (PCT or SmartCurrents), and Other DR Programs and Pilots (Farrell, 5T 1291; Exhibit A-12, Schedule B5.6, p 1, column (c)). DTE Electric also plans to invest \$18.6 million for that portfolio for the bridge period of January 2022 through November 2023, and \$5.6

million in the projected test year (Farrell, 5T 1292, Exhibit A-12, Schedule B5.6, page 1, columns (e) and (f)).⁶²

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 (Nguyen, 5T 1271; Farrell, 5T 1294). Total DR and DTE Insight capital spending was \$15.7 million in 2021 and is planned to be \$20.7 million in the 23-month bridge period ending November 30, 2023, with spending of \$6.2 million in the projected test year (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 (5T 188-94, 1304-1305).

The Interruptible Space Conditioning program (CoolCurrents) was first approved in the December 11, 2015, Order in Case No. U-17767, pp 35-36. 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. The Company replaced a cumulative total of 170,047 units as of December 31, 2022. DTE Electric is forecasting to spend \$4.2 million during the bridge period of January 2022 through November 30, 2023, and \$0.6 million for the projected test year on this program. The investment plan supports the continuation and final year of mass replacements of the existing CoolCurrents replacement program, as previously approved

⁶² 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, 5T 1292).

by the Commission ⁶³, and supports the focused expansion of the program to whole-home air source heat pump customers. (Farrell, 5T 1294-97; Exhibit A-12, Schedule B5.6, page 1, line 5, columns (e) and (f)).

The PCT program (SmartCurrents) is a direct-install DR program. By enrolling in the program, the customer receives a Wi-Fi enabled PCT and allows the Company to adjust the thermostat during DR events. The Company had 21,134 enrolled customers in the PCT program as of December 31, 2022, and is committed to growing the program through recruitment and changes in the program to provide greater flexibility and other value to customers. For example, beginning in 2023, the program will be separated from the Dynamic Peak Pricing (DPP) tariff (D1.8 rate), so customers will be able to take service under any residential electric base rate. For this program, the Company forecasts \$7.4 million of capital expenditures in the 23-month bridge period ending November 30, 2023, and \$2.5 million in the projected test period (Farrell, 5T 1297-1301; Exhibit A-12, Schedule B5.6, page 1, line 2, columns (e) and (f)).

Company witness Farrell also discussed the Bring Your Own Device (BYOD) program (Smart Savers), previously a pilot, that is available to both residential and commercial customers who already have an installed Wi-Fi enabled smart thermostat. This program enables the Company to send a control signal to raise the thermostat's set point by up to four degrees during Smart Savers Events (Farrell, 5T 1301-1303).

Other DR program improvements and pilots include: (1) implementing the DTE Smart Charge pilot, which is a Plug-in Electric Vehicle (PEV or EV) pilot; (2) implementing the Peak Time Savings (PTS) pilot for residential customers; (3) implementation plans for a battery energy

⁶³ approved by the Commission in its Orders for general rate Case Nos. U-17767, U10 18014, U-18255, U-20162, U-20561, and U-20836 and Case No. U-20471

storage pilot for or in conjunction with C&I customers; (4) developing a residential generator pilot; and (5) supporting the development of Non-Wire Alternatives (NWA) pilots that are being developed under the leadership of the Distribution Operations organization (Farrell, 5T 1304-24).

As the Company continuously strives to improve its programs for customers, it is also in the early stages of improving two programs: (1) replacement of load control devices (LCDs) in the interruptible water heating program, and (2) an enhancement for current Commercial and Industrial (C&I) interruptible customers, which consists of a dashboard or platform that would be provided to C&I customers already on an interruptible rate to help improve event performance (Farrell, 5T 1304, 1324-26).

DTE Electric is forecasting to spend \$7.1 million during the bridge period of January 2022 through November 30, 2023, and \$2.4 million for the projected test year, for this continued program improvement and pilot development (Farrell, 5T 1305; Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, columns (e) and (f)).

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

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

The Company notes that Staff relied on numbers that are generally accurate, but the presentation (See, e.g., 7T 4665) could be misinterpreted. The numbers show that customers are twice as likely to use the DTE Insight app to view their usage information (“Unique User Views” column) than going online to do so (“Customer Data Downloads” column). Therefore, the mobile application has shown to be a useful and necessary tool for customer information and engagement. Also, Insight’s weekly authentication rose significantly after the Company introduced time-of-day (TOD) rates in March of 2023 (from 646 per week in the nine weeks prior to TOD rates, to 2,702 per week in the nine weeks after TOD rates). This significant increase in use is likely to continue, and addresses Staff’s indicated concern about a lack of customer engagement (Nguyen, 5T 1280-81).

Staff’s proposal to disallow the \$4.8 million 2021 historical spend should also be rejected as this spend was to acquire 30,000 EB devices that are currently in inventory. The Commission previously approved recovery of these costs in Case No. U-20836. At that time, the Company anticipated a greater pace of customer participation. Requests for EB devices have been slower than anticipated, but there is still an increase in participation since the approval, and the Company expects to use all of the EB devices in inventory. Therefore, recovery of those costs is appropriate. The Commission should also approve the remainder of the Company’s request to continue

supporting the growing number of customers for whom Insight is by far the tool of choice to help monitor and manage their energy use (Nguyen, 5T 1281).

i. Battery Energy Storage Pilot

As discussed previously in Case No. U-20836, DTE Electric’s battery energy storage pilot is a behind-the meter (BTM) lithium-ion battery storage system (BESS) at two C&I customers’ sites. The pilot is designed to test the ability to achieve peak demand shaving or shifting during demand response (DR) events, targeting C&I customers enrolled on Rates D4, D6.2 or D11 (excluding sites or load under Rider 10) since these customers are more suited to pilot participation due to their peak load profiles, outdoor space availability and operational capabilities. The pilot is appropriate and necessary because it allows the Company to gain experience with the application of storage technology by end-use customers and interactions with the wholesale market in order to develop well-designed tariffs and related pilot programs for customer-owned battery storage, as indicated by the August 11, 2021 Order in Case No. U-21032. The Company forecasts \$4.0 million in capital expenditures in the bridge period of January 2022 through November 30, 2023, and \$0.2 million during the projected test year (Farrell, 5T 1315-20, 1329).

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:

This PFD recommends disallowing the C&I Battery Pilot costs, at least currently. DTE demonstrated that it is moving forward with the pilot, but the utility’s rebuttal testimony and briefing strangely neglected to address Staff’s specific concerns about the lack of key details about the structure of the pilot program. . . . Accordingly, this PFD agrees with Staff that it is reasonable for DTE to request approval for funding

to be included in rates *after the details of the pilot are further developed and clarified*. [Case No. U-20836 PFD, pp. 543-44. (emphasis added)]

The Commission agreed, stating:

While DTE Electric provided a number of pilot details . . . other critical elements of the pilot proposal were not included. . . . Accordingly, the Commission adopts the ALJ’s findings and conclusion on this issue and denies the proposed C&I BTM BESS pilot. . . . However, the Commission acknowledges this pilot is in line with desired learnings, *and encourages the company to seek recovery of additional costs in future rate cases when a full explanation of benefits and intended outcomes is presented*. [Case No. U-20836 Order dated November 18, 2022, p. 316 (emphasis added)]

Based on this direction, the Company resubmitted its proposal with additional detail. The Company has selected Hitachi as the specific equipment provider and pilot integrator. The batteries have left the factory, and the Company has ordered all other major equipment for the BESS. The prospective customer intends to leverage the battery to reduce peak demand charges. The Company will also leverage the battery for demand response events (Farrell, 5T 1318-20). Due to lead time of major equipment, installation at the first customer’s site has taken longer than anticipated but is planned to take place in Q3 2024. The Company plans for both batteries to be operational by the end of 2024 (Farrell, 5T 1331). The contractual agreement with the prospective customer is anticipated to be executed by the second quarter of 2023. Therefore, the Commission should approve the requested recovery (Farrell, 5T 1318-20).

Staff again is partially supportive, acknowledging the Company’s progress, but recommending “disallowing one half of the pilot expenses” (\$2.0 million) reasoning that “[b]ecause of the uncertainty about the second participant, Staff has concerns that only half of the program costs will be used and useful in the test year” (Matthews, 7T 4565-66). The Company appreciates Staff’s recognition of the Company’s progress on this pilot but disagrees with the proposed disallowance that simply splits the pilot’s costs in half, as that is not how costs for a pilot are

necessarily divided. The overall cost for both batteries was divided into milestone payments based on the project's key milestones, with the payment schedule for both batteries appropriately structured to avoid long lead time delays for equipment. A majority, 75%, of those milestone payments were already fulfilled in 2022. The remaining milestone payments for both batteries are planned for 2023 and 2024, covering the bridge and test year. The Company is confident that a second participant will be identified, and that the second battery will be installed shortly after the first. It is beneficial for the Company to fully complete the first installation so that the Company can use any learnings from that full installation to inform the process and installation for the second customer. The Company plans for both batteries to be operational by the end of 2024. Therefore, the Commission should approve full cost recovery for the pilot (Farrell, 5T 1330-31).

Staff also “recommends the Company charge some portion of the battery cost to the participating customer given the number of benefits and the amount of potential savings the C&I customer may receive from this program” (Matthews, 7T 4564). The Company disagrees because the amount of savings that a customer will receive is unknown at this time. One of the pilot's objectives is to determine this as measured by peak demand charge reduction and subsequent bill reduction during the pilot period. If the Company moves forward with a full program after the pilot, then the Company could consider an appropriate subscription model for the battery based on actual bill reduction (Farrell, 5T 1331).

Staff further “recommends the pilot have a minimum number of events called each year to ensure all functions of the battery are tested by the utility and participating customer” (Matthews, 7T 4565). The Company generally agrees with Staff's reasoning, but not the recommendation as stated. The initial proposed event schedule includes no more than 30 planned demand response events per year, and five emergency demand response events per year, with at least a one-hour

customer notice. A minimum number of planned annual events will be discussed with the host customers, and the determination of that number will consider the objective of both the utility and the customer testing the battery functionality (Farrell, 5T 1332).

ii. Residential Generator Pilot

As discussed previously in Case No. U-20836, the Company plans to conduct a residential customer-owned natural gas generator pilot. The pilot will leverage a third-party service provider's platform using telemetry to shift customers' load to the electric generator in real-time peak events. Participants will benefit from the pilot by receiving an incentive from the Company and reduced electric bills during peak events. The Company forecasts spending \$0.2 million in capital in the bridge period and test year, and \$0.2 million annually in O&M to support the pilot (Farrell, 5T 1320-21, 1324).

Staff previously recommended capital expenditure disallowances, indicating its view that the pilot is "not yet very well developed" and that shared learnings might be available from a similar Consumers' pilot. (Case No. U-20836, 8T 5528-5529, dk#754). The Commission agreed with Staff and denied recovery. (Case No. U-20836, 11/18/2022 Order, p 318).

Given that the pilot is now more "developed," the Company again seeks recovery. Company witness Farrell further explained that the Company has already selected Generac Grid Services for the implementation of the pilot. Marketing efforts and customer enrollment is planned to begin in the first quarter of 2023. The pilot will target 200 customers with a Generac Smart Grid Ready (SGR) generator, which is capable of remote operations and responding to grid events via Generac's mobile/web-based application, Mobile Link Premium. The Company intends to provide eligible customers with a free Mobile Link Premium subscription if they do not already have one. The initial design event window is 8:00 AM – 8:00 PM on weekdays, excluding holidays, and duration will

not exceed 4 hours per event and 40 hours annually. The pilot is designed to remove the entire home load during a demand response event and can be called with at least 30-minute advance notice. The Company also acted on Staff's recommendation and spoke with Consumers Energy, resulting in some modifications to this pilot based on those learnings. Therefore, with this benchmarking and further development of the pilot, the Commission should approve the requested recovery (Farrell, 5T 1322-23, 1332).

DAAO witness Koeppel recommended that the Commission reject the pilot, essentially reasoning that it would promote reliance on natural gas, and development of the gas distribution system (Koeppel, 6T 4053). Mr. Koeppel's assertions are short-sighted, unfounded, and simply incorrect. The pilot is targeting 200 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 (Farrell, 5T 1334).

Mr. Koeppel further proposed an alternative of "supplying batteries to LMI [low and moderate income] residential households . . . to simultaneously address affordability, equitable access to technology, and demand management" (Koeppel, 6T 4055). The Company disagrees that this pilot is the appropriate place for this proposal. Mr. Koeppel's proposal goes well beyond the scope and purpose of the Company's proposed pilot, which is simply to evaluate whether providing an incentive to customers who already own a generator in exchange for the Company's ability to shift the customer's household electrical usage to the generator is a viable DR program that can add value to the Company's DR portfolio (Farrell, 5T 1334).

Therefore, the Commission should approve full funding for the Company's proposed pilot and reject Mr. Koepfel's proposal to create a program designed for a different purpose.⁶⁴

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 Categories (see, e.g., 5T 1826). Total IT capital spending was \$158.0 million in the 2021 historical test year, and is projected to be \$318.0 million for the 23-month period ending November 30, 2023, and \$170.5 million for the projected test year (Sharma, 5T 1820; Exhibit A-12, Schedule B5.7, p1, line 11, columns (b), (e), and (f)).

DTE Electric has a robust IT capital investment planning process, which is known as the Annual Planning Cycle (APC), with output from that process included in this case. Exhibit A-12, Schedule B5.7 summarizes IT capital cost by investment category and portfolio. Exhibit A-12, Schedules B5.7.1 through B5.7.9 present the capital spending in each portfolio. Exhibit A-24, Schedule N1 presents the executive summaries for each business case associated with each IT project over \$250,000.⁶⁵ Exhibit A-24, Schedule N-3 Revised provides a greater level of detail for each of the IT projects, presented by year and then in portfolio/project order. The Company has also provided a new Exhibit A-24, Schedule N4, which is designed to provide guidance connecting each IT requirement to the associated exhibit and/or workpaper that demonstrates reasonableness and prudence (Hatsios, 5T 1594; Sharma, 5T 1820-24, 1830-31).

⁶⁴ 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 IV.

⁶⁵ There are also 42 projects with IT capital spending less than \$250,000, but which are necessary investments to collectively support the IT Portfolio (Sharma, 5T 2041; Exhibit A-12, Schedule B5.7, page 1, line 18).

Mr. 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, and IT Projects less than \$250,000, as indicated above and summarized at Exhibit A-12, Schedule B5.7, page 1, lines 13-18. 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 (Sharma, 5T 1831). Capital expenditures were \$17.1 million in the 2021 historical test year, and are projected to be \$19.6 million in the 23 months ending November 30, 2023, and \$12.0 million in the projected test year (Sharma, 5T 1831-32; 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); see also 5T 1832-34 (Regulatory/Compliance), 5T 1834-42 (Sustainment), 5T 1842-46 (Return-to-Health), 5T 1846-51 (IT Enhancements), and 5T 1851-59 (Strategic)).
2. The Customer Service Portfolio consists of key systems integrating with the Company's SAP Customer Relationship and Billing (CR&B) platform (Sharma, 5T 1860). Mr. Sharma supported capital expenditures in the Sustainment and Return-to-Health categories, which were \$23.8 million in the 2021 historical test year, and are projected to be \$42.3 million in the 23 months ending November 30, 2023, and \$20.2 million in the projected test year (Sharma, 5T 1860-61; Exhibit A-12, Schedule B5.7, page 1, line 3, columns (b), (e), and (f); Exhibit A-12, Schedule B5.7.2, line 25, columns (d), (g), and (h)). Details regarding projects grouped by

category are at Sharma, 5T 1861-78 (Sustainment), and 5T 1878-91 (Return-to-Health).

Company witness Hatsios supported capital investments included in the Customer IT Portfolio in the Regulatory & Compliance, IT Enhancements, and Strategic categories, which were \$29.5 million in the 2021 historical test year, and are projected to be \$103.7 million in the 23 months ending November 30, 2023, and \$52.7 million for the projected test year. (Hatsios, 5T 1590, 1601-1603; Exhibit A-12, Schedule B5.7, page 1, line 4, columns ((b), (e), and (f); Exhibit A-12, Schedule B5.7.3 Revised,⁶⁶p 1, line 61, 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 5T 1604-1665 (Projects that Reduce Call Volumes), 5T 1665-94 (Projects Creating Operational Efficiencies), 5T 1694-1723 (Projects that Enhance Customer Interactions), 5T 1723-27 (Projects that Reform Collection Experiences), and 5T 1727-35 (EWR & Clean Energy Projects).

Mr. Hatsios also supported an additional \$9.0 million in Regulatory/Compliance capital expenditures for non-discretionary investments required to satisfy MPSC standards and orders, and other industry regulations and compliance items to which the Company must adhere in order to provide service to its customers (Hatsios, 5T 1603, 1735-40).

3. The Plant and Field Portfolio supports IT business systems that are used by the organizations such as Distribution Operations (DO), Energy Supply (ENS), Generation Optimization (GenOpts), and Fermi (Sharma, 5T 1891). Capital

⁶⁶ In direct testimony, Mr. Hatsios withdrew \$2.6 million from the projected test year capital (5T 1742-1743).

expenditures were \$33.6 million in the 2021 historical test year, and are projected to be \$60.8 million in the 23 months ending November 30, 2023, and \$26.8 million in the projected test year. (5T 1892; Exhibit A-12, Schedule B5.7, page 1, line 5, columns (b), (e), and (f); Exhibit A-12, Schedule B5.7.4 Revised, line 42, columns (d), (g), and (h)). Details regarding projects grouped by category are at 5T 1893-1914 (Regulatory/Compliance), 5T 1914-28 (Return-to-Health), 5T 1928-29 (IT Enhancements), and 5T 1929-43 (Strategic).

4. The Information Technology for IT Portfolio consists of capital projects that represent 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. (5T 1943) Capital expenditures were \$19.1 million in the 2021 historical test period, and are projected to be \$23.3 million in the 23 months ending November 30, 2023, and \$32.3 million in the projected test year. (5T 1943-44; Exhibit A-12, Schedule B5.7, p1, line 6, columns (b), (e), and (f); Exhibit A-12, Schedule 5.7.5, line 38, columns (d), (g), and (h)). Details regarding projects grouped by category are at 5T 1944-48 (Regulatory/Compliance), 5T 1949-52 (Sustainment), 5T 1952-53 (Return-to-Health), 5T 1953-56 (IT Enhancements), and 5T 1956-87 (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). (5T 1987). Capital expenditures were \$7.7 million in the 2021 historical test year, and are projected to be \$5.4 million in the 23 months ending November 30, 2023, and \$3.3 million in the projected test year. (5T 1988-89; Exhibit A-12, Schedule B5.7, p 1, line 7, columns (b), (e), and (f); Exhibit

A-12, Schedule B5.7.6, line 15, columns (d), (g), and (h)). Details regarding projects grouped by category are discussed by Company witness Sharma at 5T 1989-91 (Regulatory/Compliance), 5T 1991-95 (Return-to-Health), 5T 1995-96 (IT Enhancements), and 5T 1996-2000 (Strategic).

6. The Infrastructure Operations Portfolio is responsible for the design, implementation, and secure operation of the Company's overall IT infrastructure. (5T 2000-2001). Capital expenditures were \$20.4 million in the 2021 historical test year, and are projected to be \$59.7 million in the 23 months ending November 30, 2023, and \$21.7 million in the projected test year. (5 T 2001; Exhibit A-12, Schedule B5.7, page 1, line 8, columns (b), (e), and (f); Exhibit A-12, Schedule B5.7.7 Revised, line 32, columns (d), (g), and (h)). Details regarding projects grouped by category are discussed by Company witness Sharma at 5T 2002-2004 (Regulatory/Compliance), 5T 2004-12 (Sustainment), 5T 2012-29 (Return-to-Health), and 5T 2029-34 (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. (5T 2034). Capital expenditures were \$4.8 million in the 2021 historical test year, and are projected to be \$3.2 million

in the 23 months ending November 30, 2023, and \$1.5 million in the projected test year. (5T 2034-35; Exhibit A-12, Schedule B5.7, page 1, line 9, columns (b), (e), and (f); Exhibit A-12, Schedule B5.7.8, line 9, columns (d), (g), and (h)). Details regarding projects grouped by category are discussed by Company witness Sharma at 5T 2035-36 (Sustainment), and 5T 2036-37 (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. (5T 2037). The Company seeks to recover the \$2.2 million that it spent on Innovation investments in the 2021 historical test year. This cost is categorized entirely as strategic investments. (5T 2037; Exhibit A-12, Schedule B5.7, line 10, column (b); Exhibit A-12, Schedule B5.7.9, line 1, column (d)). Details regarding the Applied Innovations Team and the solutions that were developed through the Innovation project are discussed by Company witness Sharma at 5T 2038-41.

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 \$158.2 million of capital on IT projects in 2021, compared to the \$121.8 million authorized in Case No. U-20836 (5T 2042; Exhibit A-24, Schedule N2, line 9). Mr. Sharma 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 (5T 1868, 1897, 1952-1953, 1997, 2016, 2019 and 2042-43). None of the intervening

parties took issue with the 2021 projects and respective variances. The 2021 variance in the Customer IT Portfolio was for the Prepay project, which the Commission disallowed (5T 1778).

i. IT Projects with a Level 2 Cost Estimate

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

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

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

be more accurate to compare Level 2 estimates to AACE class 2 estimates with a -15% to +20% range. (5T 2048-49).

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

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

ii. Staff's Individual IT Project Disallowances

a. Oracle Financial Planning Tool

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

This view is incorrect for a few reasons. First, Staff's reasoning that cost savings is the only benefit or reason for the project fails to consider that the project will improve productivity and increase efficiency in both the short term and long term. Second, the Company completed a comprehensive review of financial planning solutions available in the market and found that the Oracle EPM provides a viable solution at the lowest cost to achieve replacement of the current

unsustainable process. Company witness Sharma’s testimony further demonstrates that the investment is justified, prudent, and necessary (5T 1854-56, 2053).

b. Infrastructure Automation Maturity

Staff proposed a complete disallowance (\$0.41 million in the projected test year), reasoning that the project “is a ‘nice to have’ investment, however it is not a necessity and is an imprudent cost to pass onto ratepayers.” (7T 4659).

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

c. Infrastructure Operations Center (IOC) Automation

As with the Infrastructure Automation Maturity project, Staff proposed a complete disallowance (\$0.41 million in the projected test year) of the Infrastructure Operations Center (IOC) Automation project, reasoning that the project “is a ‘nice to have’ investment, however it is not a necessity and is an unjustified cost to pass onto ratepayers.” (7T 4660). Staff further suggested that cost is the only consideration and “tasks will still be completed” without the project (*Id.*).

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

d. DTE Electric Utility Network (UN)

The Company will invest \$0.7 million in the DTE Electric Utility Network (UN) project over the course of 35-months ending November 30, 2024, as shown on line 7 of Exhibit A-12 Schedule B5.7.4 Revised (5T 1902). The DTE Electric Utility Network project will implement the new ESRI UN product in the cloud to replace the ArcMap platform that will no longer be supported by Q1 2025. This product replacement will increase availability, recoverability, scalability, and security while enabling business process efficiency. (5T 1903). Staff proposed a 50% reduction of this investment, reasoning that “the Company is projecting \$375,000 in capital expenditures for 2023 and 2024. Staff’s position is that by virtue of the two projected amounts being identical, said projections are likely preliminary and the actual expenditure amounts could be different . . . Therefore, I applied a 50% reduction . . . [which] results in downward adjustments of \$171,875 for the 11 months ending 11/30/2023 and \$187,500 to the test year.” (7T 4415-16).

The Company disagrees with Staff on this point because this sustainment effort is complete in detailed scoping including robust requirements documentation. The annual cost breakdown reflects the internal and external labor by resource group. The consistency in annual costs reflects a planned schedule of spending with the allocated resources. (5T 1902-1905, 2055; Exhibit A-43, Schedule HH1).

e. Supervisory Control and Data Acquisition (SCADA)

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

amount to arrive at downward adjustments of] \$134,904 for the 11 months ending 11/30/2023” and “\$147,168 to the test year.” (7T 4418-19).

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

f. ESRI Application Health

Staff reasoned that “the Company is projecting \$440,000 in capital expenditures for 2023 and 2024. Staff’s position is that, by virtue of the two projected amounts being identical, said projections are likely preliminary and the actual expenditure amounts could be different. Therefore, I averaged the actual spending from 2019 through 2022 . . . and prorated the historic average amounts to arrive at downward adjustments of \$93,149 for the 11 months ending 11/30/2023” and “\$101,617 to the test year” (Evans, 7T 4419).

The Company disagrees for two reasons. First, Staff’s use of historic spending is inappropriate because investments in this asset were put on hold while supporting the overall ERSI Upgrade project. The Company was thereby able to maximize efficiencies and complete this support under its forecast in 2021. Second, the annual cost reflects the required labor by resource

group. The similarity of the Company's annual costs simply reflects a planned level of spending with finite resource allocation to deliver the project (Sharma, 5T 2057-58; Exhibit A-43, Schedule HH3).

g. Changing Bill Size

This project is to standardize the size of paper on which bills are printed because bills are currently printed on a custom-size paper that is supplied by only one supplier. The implementation of this project will result in cost savings, risk reductions, and efficiencies, as explained by Company witness Hatsios. (5T 1681-82). Staff recommended a total (\$900,000) disallowance (\$731,000 in the bridge period; \$169,000 in the projected test year), reasoning that this is a "DTE-created issue" and Staff did not see any advantage for customers. (7T 4548-49). In Mr. Hatsios' rebuttal testimony, the Company quantified the customer benefits from switching to a standard-sized paper. The conversion would reduce the cost of printed bills by approximately \$300,000 per year through negotiation of more competitive paper prices, a reduction in the cost of bill envelopes, and more favorable terms from the expansion of the pool of vendors. In fact, the annual savings will continue in perpetuity. The Commission therefore should reject Staff's proposed disallowance and determine that the Company's \$900,000 investment is reasonable and prudent, based on the clear customer benefits. (5T 1783).

iii. DAAO's proposed disallowances.

a. Advanced Analytics (AA) Use Cases.

DTE Electric is investing \$4.3 million in resources and technologies that will provide greater insight into customer segments, behaviors, and the customer experience. (5T 1725). DAAO witness Koeppel proposed a complete (\$4.3 million) disallowance (\$1.8 million for the bridge

period; \$2.5 million for the test year), noting one aspect of the Use Cases (reducing collection agency fees by \$40,000 per year) and asserting that “[t]hese approaches are consistent with the Company’s Profit Maximization Principle in that they reduce operations spending and increase capital spending on which the Company can earn a profit. As presented, these investments are not reasonable and prudent, as their impact is merely to expend ratepayer resources on more tools to navigate the complex morass of programs rather than to simply and unify the programs.” (6T 4015).

DAAO is wrong for several reasons. First, Mr. Koepfel creates unnecessary confusion by comingling the 2023 and 2024 Use Cases in making his argument. The 2023 Use Case referenced by Mr. Koepfel optimizes the Company’s third-party collection processes through integration of the machine learning propensity-to-pay model, which was developed and tested in a separate 2022 Use Case, in which the Company invested ~\$700,000 of the \$1.4 million spend in 2022. The 2022 Use Cases also involved the development of a second machine learning model to help the Company understand where in the collection process customers are experiencing the most friction and dissatisfaction, allowing the Company to identify and implement opportunities to reduce that friction and help customers. Mr. Koepfel’s focus on the Company’s reduction of \$40,000 collection agency fees relates to the 2023 use case (\$0.4 million), which will optimize the allocation of customers to the Company’s third-party collection agencies through integration with our SAP CR&B system and collection processes. The Company maintains that this is a reasonable and prudent investment, and Mr. Koepfel does not suggest otherwise except by vague reference to unfounded suspicions. (5T 1725-26, 1798-99).

Mr. Koepfel’s further reference to a “morass” of programs relates to the 2024 Use Case (\$2.5 million), which is unrelated to the 2022 and 2023 use cases. The 2024 Use Case addresses inefficiencies in the energy assistance application process, which requires that customers who are

struggling to pay their past-due balances contact the Company, or a third-party energy assistance agency, to determine their eligibility for various forms of state, federal and utility assistance programs. Mr. Koeppel suggests that the Company should simplify the “morass” of programs, but the Company does not control the various agencies or the administration of the programs. The 2024 Use Case addresses this issue by building a machine learning model that can predict a customer’s energy assistance eligibility, so the Company can proactively reach out to vulnerable customers who qualify for energy assistance and reduce the complexity for them in applying for that assistance. Thus, the 2024 investment does exactly what Mr. Koeppel suggests by simplifying the process and making sure that the right customers are referred to the right agency/program for assistance. (5T 1726-27, 1799-1800).

b. DAAO’s other concerns.

In response to Mr. Koeppel’s indicated concerns about the Company’s customer service (6T 4016-18), Company witness Hatsios explained that the Company strives to provide the highest levels of customer service and has benchmarked well against its peers in overall customer satisfaction surveys. (Hatsios, 5T 1800-1801). The Company also seeks to continuously improve all aspects of the customer’s experience, and in many cases has projects and efforts in place to address Mr. Koeppel’s indicated customer service concerns. (Hatsios, 5T 1801-1803; 5T 1700-1718). For example, Mr. Hatsios also addressed Ann Arbor Fire Chief Kennedy’s indicated concerns about attempting to contact DTE Electric during catastrophic storms (5T 1806-11), Ann Arbor witness Stults’ concerns about the DTE Electric Outage Map (5T 1811-12), and MI-MAUI witness Bunch’s request that the Company share information about vulnerable residents who might be at risk during a service interruption or extreme weather event. (5T 1812-13).

Mr. Koepfel further indicated that \$51.3 million of proposed capital expenditures on self-service IT would produce only “customer savings of “\$5.4 million.” (6T 4018). It appears that Mr. Koepfel misinterpreted a net present value (NPV) analysis. These investments create net revenue requirement savings of approximately \$4 million for customers starting in 2027, which grows to sustained savings of approximately \$14 million by 2035. Discounting these net cash flows back into today’s dollars yields a negative \$5.4 million, indicating that the investments provide savings to customers, and supporting the reasonableness and prudence of the investments. (5T 1619-23, 1806; Exhibit A-24, Schedule N6, Tab 1, line 22).

Mr. Koepfel further suggested that “the Commission open an inquiry into the standards for treating IT investments as capital,” and that “[i]t is also unclear . . . whether there is a clear standard of which kinds of IT expenses are considered capital and which are considered operations.” (6T 4018-19). The Company disagrees because its capitalization policy for IT projects is consistent with the rules in the Uniform System of Accounts and Generally Accepted Accounting Principles. Mr. Koepfel’s suggestion lacks merit and therefore should be rejected (Uzenski, 5T 1519-20, 156, 1582).

8. Corporate Staff Group

Corporate Staff Group (CSG) capital spending for physical infrastructure, fleet, and other projects was \$93.9 million in 2021, and is projected to be \$263.9 million for the 23 months ending November 30, 2023 and \$111.1 million for the projected test year. (5T 1523; 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 (Facilities Renovation), line 4 (Service Center

Optimization and Modernization), line 5 (Security Measures), and line 6 (Other Miscellaneous). (5T 1523-33). These costs are reasonable, prudent, and should be approved.

VI. RATE OF RETURN

DTE Electric requests a weighted, after-tax 5.70% overall rate of return (Vangilder, 5T 2592; Exhibit A-14, Schedule D1, line 10, column (g)), which the Commission should adopt for the reasons discussed below.

A. Capital Structure

DTE Electric seeks to maintain its permanent capital structure of 50% debt and 50% equity (Lepczyk, 5T 3263, 3266-67, 3276; Exhibit A-14, Schedule D1. See also; May 2, 2019 Order in Case No. U-20162, pp 54-55; May 8, 2020 Order in Case No. U-20561, p 166; November 18, 2022 Order in Case No. U-20836, p 225). Staff (Ufolla, 7T 4704), and the AG (Coppola, 6T 3728) agreed.

Although there appears to be no disagreement, 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, 5T 3265-68).

The Company is using the previously-authorized capital structure to reduce the number of contested issues in this case; however, it would be reasonable and prudent to increase the equity ratio to 52%, which is the average equity ratio for the Company's peers (Lepczyk, 5T 3267; Exhibit A-14, Schedule D1.1).

DTE Electric also had a 50% equity ratio on December 31, 2021 and is committed to maintaining a 50% equity ratio. DTE Energy made over \$1.8 billion of equity infusions from 2017-2021, equity infusions totaling \$599 million in 2022, and will infuse the amounts necessary in future years to maintain a 50% equity ratio (Lepczyk, 5T 3268).

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 challenges, as further discussed below regarding ROE. Accordingly, the Commission should maintain DTE Electric's 50% equity ratio.

B. Debt Cost Rates

1. Long-Term Debt

DTE Electric recommends a 4.06% 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, 5T 3264, 3271, 3276; Exhibit A-14, Schedule D2). Staff (Ufolla, 7T 4704) and the AG (Coppola, 6T 3729) agree.

2. Short-Term Debt

DTE Electric recommends a 4.98% 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, 5T 3264, 3272, 3276; Exhibit A-14, Schedule D3). Staff (Ufolla, 7T 4704) and the AG (Coppola, 6T 3729) agree.

C. Return on Common Equity

Company witness Dr. Villadsen explained and recommended that a just and reasonable Return on Equity (ROE) for DTE Electric's common equity capital is 10.25%.⁶⁷ This is the midpoint of a reasonable range, and is conservative because DTE Electric has greater-than-average risk. (Villadsen, 5T 2954-55, 2995, 2999, 3044).

Staff (Ufolla, 7T 4704, 4720-21) and the AG (Coppola, 6T 3728) recommended 9.8%. ABATE recommended 9.55% (Walters, 4T 1154-55, 1207). As usual, these were the only three parties that offered any substantive analysis to support their recommendations.⁶⁸ The most noteworthy thing about Staff, the AG, and ABATE's recommendations is that they all recommend a higher (by 0.15% to 0.3%) ROE than they did in Case No. U-20836, where Staff recommended 9.6% (Ufolla, Case No. U-20836, 8T 5085-5100-5101), the AG recommended 9.5% (Coppola, Case No. U-20836, 8T 4818, 4846), and ABATE recommended 9.4% (Walters, Case No. U-20836, 8T 3046-3047). Thus, they all essentially acknowledge that times have changed since the

⁶⁷ DTE Electric has no preferred stock (Exhibit A-14, Schedule D4).

⁶⁸ Other witnesses suggested that the Company's ROE should either not increase, or be reduced, but did not support their recommendations with a ROE analysis using financial market data. Thus, their unfounded and irrelevant assertions cannot support a decision and merit no serious consideration. (Villadsen, 5T 3046, 3048, 3053-55, 3087-90). See also section IV above.

Commission set DTE Electric's ROE at 9.9%, and that the consistently-used forms of ROE modeling indicate a higher cost of equity.

Based on the present and continuing circumstances reflected in this case, it is not credible to suggest that there is any sound basis to decrease the Company's ROE, and the only viable inquiry concerns how much it should be increased. Dr. Villadsen further explained, in part:

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

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

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

Dr. Villadsen estimated the ROE for each company in her sample using two versions of both the Capital Asset Pricing Model (CAPM),⁶⁹ 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, 5T 2959-63, 2984-85).

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

1. CAPM and ECAPM Estimates

Dr. Villadsen developed ROE estimates based on the CAPM and an empirical approximation to the CAPM (ECAPM). The CAPM is based on the idea that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk using (a) a risk-free rate, (b) beta,⁷⁰ and (c) a market risk premium (MRP). (Villadsen, 5T 2985).

⁶⁹ The CAPM is a risk positioning risk positioning approach. Dr. Villadsen also used the Empirical CAPM (ECAPM) (Villadsen, 5T 2962, 2985).

⁷⁰ Beta is a measure of the risks that cannot be eliminated by diversification. It measures the "systematic" risk of a stock – the extent to which the stock's value fluctuates more or less than the market fluctuates (Villadsen, 5T 2985).

Dr. Villadsen further explained that empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta. Low-beta stocks tend to have higher risk premiums than predicted by the CAPM, whereas high-beta stocks tend to have lower risk premiums than predicted by the CAPM. Dr. Villadsen adjusted by using the ECAPM, which uses these empirical findings to produce results that more closely match the results of empirical tests (Villadsen, 5T 2986). Criticisms of the ECAPM are misplaced, but the ECAPM has little if any effect on Dr. Villadsen's estimated ROE, so she relegated her discussion to an appendix (Villadsen, 5T 3057).

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

The Electric Utility Sample's results are consistent with a cost-of-equity range of 9.0% to 11.5% (ignoring the financial risk adjustment that the Commission criticized in the past). Rounding to the nearest $\frac{1}{4}$ percent (which is Dr. Villadsen's practice), the CAPM (and ECAPM, which is virtually no different) indicates a ROE range of 9.0% to 11.5% for the Electric Utility Sample before any DTE Electric risks are considered. The Natural Gas Sample has comparable to slightly lower results (Villadsen, 5T 2989).

Staff computed a ROE of 10.34% using an historical CAPM, and 13.63% using a projected CAPM, but “heavily discounted” the projected CAPM (Ufolla, 7T 4713, 4715-16). Dr. Villadsen agreed with the use of multiple CAPM scenarios, but disagreed with Staff’s decision to essentially ignore half of the results, explaining that this significantly affected the outcome of Staff’s ROE analysis. For example, the average of the CAPM results is 11.99%, but Staff’s upper bound on the ROE is 10.3%, which is the historical CAPM result. If the projected CAPM result is included, the average of the DCF, CAPM, and risk premium models is 10.4%. Thus, Staff’s own modeling supports a 10.4% ROE average, which is significantly above Staff’s 9.8% ROE recommendation, and more in line with the Company’s 10.25% request (Villadsen, 5T 3052, 2064).

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

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

2. DCF Estimates

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

Dr. Villadsen calculated both the single-stage and multi-stage DCF using growth rates from *Value Line* and *IBES*, as well as GDP forecasts from *Blue Chip Economic Indicators* for the multi-stage DCF. The corresponding ROE estimates range from 8.9% to 10.7% for the Electric Utility Sample, and 8.7% to 11.0% for the Natural Gas Sample. Dr. Villadsen viewed the multi-stage results (8.9% and 8.7%) as unrepresentative, however, because they are out of line with other results, and might fail to capture the substantial growth needed in the electric sector to accomplish the transition to a low-carbon economy. Therefore, she considered the upper half of the range determined by the estimation results reasonable. That is a reasonable range of 9.8% to 10.7, with a midpoint of 10.25%, before any DTE Electric risks are considered (Villadsen, 5T 2992).

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

3. Risk Premium Estimate

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

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

In DTE Electric's 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. [Case No. U-20836 Order dated November 18, 2022, pp. 242-43. Footnote omitted.]

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

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

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

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

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.

In addition to the discussion near the beginning of this section, Dr. Villadsen explained that interest rates have increased substantially since the record was made in Case No. U-20836. At the same time, systemic risk as measured by beta remains relatively constant,⁷¹ as does the historical market risk premium, so the estimated cost of equity is now higher than what is reflected in the data that the Commission reviewed in Case No. U-20836 (Villadsen, 5T 2955).

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

Overall, the state of U.S. capital markets indicates that we are experiencing the highest level of inflation since the stagflation of the late 1970s to early 1980s. We have entered into a period of rising interest rates, which are expected to continue to rise to combat increasing inflation, and we are experiencing substantial global uncertainty in Europe due to the war in Ukraine. The recent monetary tightening taken by the Federal Reserve tightened monetary policy and increased interest rates.

Taken together, these facts indicate that an increase in the allowed ROE relative to DTE Electric's last rate case to 10.25% is warranted to compensate DTE Electric's investors for the systemic risk that currently is incurred and the risk to which the investors are expected to be exposed [while] the allowed ROE is in place. [Villadsen, 5T 2977.]

AG witness Coppola also acknowledged that "in late 2021 and early 2022, inflation has become a concern. To combat this threat, the Federal reserve has increased short term interest

⁷¹ Beta remains high at 0.88 for the Electric Utility Sample (Villadsen, 5T 2982), as compared to approximately 0.6% in Case No. U-20561 where the Commission set DTE Electric's ROE at 9.9%.

rates” (6T 3750) and “the current state of the economy and financial markets has increased business risk” (6T 3758).

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 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.” (Case No. U-18014 Order dated January 31, 2017, 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” (Case No. U-17767 Order dated December 11, 2015, 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, and in addition to ongoing uncertainty in the capital markets discussed above, DTE Electric faces increased risk of under-recovery because its service territory includes the greater Detroit area, which continues to be economically challenged. This risk has also recently increased because during times of high inflation, the impact on communities with lower income is larger. DTE Electric also has an asymmetrical risk (downside risk with no corresponding upside) due to the responsibilities of owning and safely operating a nuclear power plant. Therefore, DTE Electric has a higher-than-average business risk relative to companies in Dr. Villadsen’s sample (Villadsen, 5T 2955, 2995-98).

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, 5 5T 2959-62).

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

Primarily due to increased interest rates, the current cost of equity is higher than it was when the Commission set DTE Electric's ROE at 9.9% in Case No. U-20561 and maintained it in Case No. U-20836. The average of the low and high estimates from Dr. Villadsen's DCF, CAPM and Risk Premium models results in a range of 9.7% to 10.8%, the midpoint of which is 10.25%. This is a conservative estimate for DTE Electric's ROE because DTE Electric has higher-than-average risk compared to the sample companies, so it would be reasonable to place DTE Electric in the upper half of the estimates (Villadsen, 5T 2999).

Proposals to lower DTE Electric's ROE are also inappropriate in today's financial environment of high inflation, rising interest rates, and continuing business risk. ROEs have increased in recent months, as have indicators of the cost of equity (Villadsen, 5T 3046-47, 3049-50, 3087-88). It is also important to maintain DTE Electric's access to capital. Maintaining a solid credit rating and outlook is one important aspect to maintaining access to capital. A supportive allowed return on equity is important to ensure the utility's favorable access to credit markets.

Maintaining a strong credit rating is particularly critical during a period forecast to have substantial capital investment for infrastructure.

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 3.69% and 10.25%, respectively. Deferred income taxes are at zero cost (Vangilder, 5T 2595-96; 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 5.70% overall rate of return (Vangilder, 5T 2592; Exhibit A-14, Schedule D1, line 10, column (g)). A 1.3496 revenue conversion factor is appropriate for the projected period (Vangilder, 5T 2592; Exhibit A-13, Schedule C2). The corresponding weighted pre-tax overall rate of return is 7.11% (Exhibit A-14, Schedule D1, line 10, column (i)). DTE Electric supports the use of the 5.70% overall rate of return in the derivation of its revenue requirements and the use of the 7.11% pre-tax overall rate for the return on rate base.

VII. ADJUSTED NET OPERATING INCOME AND REVENUE DEFICIENCY

DTE Electric's Total Electric Adjusted Net Operating Income (NOI) was \$1,089.6 million in the 2021 historical test year, and was projected to be \$836.8 million in the projected test period (Uzenski, 5T 1497, 1513; Exhibit A-13, Schedule C1, line 17). DTE Electric's operating income is projected to decrease due to increased O&M, depreciation and property taxes related to capital additions, and lower sales. The decrease in operating income is partially offset by higher revenues

from new base rates in Case No. U-20836, effective late November 2022, and lower income taxes (Uzenski, 5T 1512). 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 \$847.9 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, 5T 2508, 2532-37). In Case No. U-20836, Staff agreed with the Company's forecast (Case No. U-20836, Staff Initial Brief, p 155, dk#790). The only dispute was by the AG, whose witness proposed to increase the residential sales forecast due to the Company's use of Google Maps mobility data (sometimes described as a "wedge") to reflect the impacts of the COVID-19 pandemic, although he accepted the Company's C&I forecast, which used the same "wedge" (Case No. U-20836, Coppola, 7T 2621, 2642). The PFD agreed with Staff and the Company:

This PFD agrees with Staff and recommends adopting DTE's sales forecast. This PFD acknowledges the Attorney General's challenges to the utility's forecast but ultimately concludes that DTE's rebuttal testimony sufficiently addressed the issues raised to validate the adequacy of [the] company's forecast. [Case No. U-20836 PFD, p 462.]

The Commission instead (1) rejected the PFD's recommendation to approve the Company's forecast due to the use of a "wedge" adjustment, (2) rejected Staff's sales analyses, and (3) defaulted to the AG's simple assumption that the most recent full-year COVID-19-impacted residential use per customer levels from 2021 would continue unabated into the future (Case No. U-20836 Order dated November 18, 2022, pp. 250-51). The Commission also denied rehearing (Case No. U-20836 Order on Rehearing dated February 2, 2023). This resulted in an inaccurate residential forecast

forming the basis for the Case No. U-20836 Order. There is no such dispute in the instant proceeding.

Company forecasting expert Mr. Leuker explained that the U-20836 forecasting period is November 2022 through October 2023 (Leuker 5T 2532). The actual temperature-normalized residential sales for November and December of 2022 deviated from the Commission-adopted (adjusted 796.4 GWh higher) forecast by (144) GWh (5.6%) for an accuracy of 94.4%. In contrast, the Company's U-20836 residential forecast deviates from actual temperature-normalized sales by only (14) GWh (0.6%) for an accuracy of 99.4% (Leuker, 5T 2532-33). Similarly, the Company's small C&I forecast had 100% accuracy, and the Company's large C&I forecast had 97.8% accuracy. Both forecasts exceed the 5-year average achieved in benchmarking results (Leuker, 5T 2533, 2536; Exhibit A-15, Schedule E5, page 2).

On average, for historical years 2017 through 2021, the absolute percent variance for the Company's total sales forecast is 1.82% (Leuker, 5T 2534; Exhibit A-15, Schedule E5, page 1). There was some deviation due to the COVID-19 pandemic.⁷² Excluding 2020 and 2021, the average absolute percentage variance in the Company's forecast is below 0.5% for both the residential and small C&I class, near 1.5% for the large C&I class, and less than 1% in total sales across all classes (Leuker, 5T 2536; Exhibit A-15, Schedule E5, page 1, line 239. DTE Electric is also on par with peer utilities across the nation in forecasting by customer class and peak demand (Leuker, 5T 2537; Exhibit A-15, Schedule E5, page 2).

⁷² 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, 5T 2535). The 2021 total sales forecast compared to total weather-normalized service area sales still reflects 97.5% accuracy (Leuker, 5T 3534).

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 DG growth, fleet EV growth, and large customer projects that are informed by customer account managers. (Leuker, 5T 2508-2517). Mr. Bellini provided the Other (street lighting) forecast (Bellini, 5T 2621-22).

The Company's forecasting methodology is generally the same as it was in Case No. U-20836, with updated data. The one methodological change was to not use the "wedge" that was computed using Google Mobility data. Yet the Company is still experiencing slightly higher residential sales volumes compared to pre-pandemic levels, indicating that although COVID-19 restrictions have been lifted, people are still choosing or able to work from home. Ignoring this reality would result in an inaccurate forecast, as discussed above. Therefore, it is important to find another method to help explain these variations (Leuker, 5T 2517-20).

Therefore, the Company's forecast uses Kastle's Back to Work Barometer to capture the changes in workplace dynamics caused by impacts from the pandemic and the associated impacts on the sales variances experienced since March 2020. The Back to Work Barometer is a work-from-home index that measures key card swipes in commercial buildings and compares them to pre-pandemic levels to identify trends in how workers are returning to the office (Leuker, 5T 2518).

This resolves the correlation (between moving around and electricity consumption) concern that led to the Commission’s rejection of the “wedge” (Case No. U-20836 Order dated November 18, 2022, p. 250 “The Commission finds the strength of the correlation between mobility data and electric consumption to be unpersuasive. As the Attorney General stated, ‘[n]o direct connection has been presented showing that individuals moving around in a certain geographic area will result in changes in their electricity consumption.’ 8 Tr 4851.”).

Unlike Google mobility data which *indirectly* measures home versus office work by using travel patterns measured through cellphone data, the Kastle data *directly* measures workplace occupancy. The data therefore has strong theoretical validity for forecasting use. The methodology is also simple to apply (in contrast to relying on a calculation), with the data used as a direct input into the utilization equation, in the same manner as household income and household size (Leuker, 5T 2518-20).

The Company also performed back testing to validate using the Kastle data. The residential sales forecast was validated using 34 months of out-of-sample testing (from January of 2019 to October of 2022). Including the Kastle data yields an average error of 1.2%, while excluding the data yields an average error of 4.0% (Leuker, 5T 2520). The long testing period also resolves the Commission’s indicated concern about analytical rigor with only six months of testing for the Google mobility data. (Case No. U-20836 Order dated November 18, 2022, p. 250 “The Commission acknowledges that the company found Google Mobility data to be statistically significant; however, six months of out-of-sample testing does not provide the analytical rigor which the Commission expects companies to project sales multiple years into the future”)

For the projected test period, service area sales are projected to be 44,310 GWh, and bundled sales are projected to be 39,862 GWh (Leuker, 5T 2526; Exhibit A-15, Schedule E1, pages 1

through 3). Service area system output and annual peak demand are projected to be 47,789 GWh and 10,916 MW, respectively. Bundled system output and annual peak demand are projected to be 43,093 GWh and 10,171 MW, respectively (Leuker, 5 T 2531; Exhibit A-15, Schedule E2, pages 1 and 2).

Mr. Leuker further explained that service area sales are expected to decrease to 44,012 GWh in 2027. This represents a 0.6% average annual decrease. Bundled sales are expected to decline to 39,600 GWh in 2027. This represents a -0.7% compound annual growth rate (CAGR). (5T 2526-27).⁷³

No party presented contrary or alternative testimony. Therefore, the ALJ should recommend, and 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

⁷³ DTE Electric's service area Residential Class sales are projected to decline 1.7% annually, on average, between 2021 and the projected period in this case, and increase by 1.0% annually, on average, through 2027. DTE Electric's service area Small C&I class sales are forecast to decrease 0.2% annually, on average, between 2021 and the projected period, and to increase by 0.4% annually, on average, through 2027 (Leuker, 5T 2527-28). DTE Electric's service area Large C&I class sales are projected to decrease by 0.6% annually, on average, from 2021 to the projected period. DTE Electric's service area Other Class (which consists of street lighting and traffic signals) sales are projected to decline by 1.7% annually, on average, from 2021 through 2027, mainly due to the use of more efficient lighting (Leuker, 5T 2529-31). Choice sales are projected to increase to 4,412 GWh in 2027, which represents a 0.2% CAGR (Leuker, 5T 2527).

DTE Electric's temperature-normalized service area system peak demand declines from 11,358 MW in 2021 to 10,818 MW in 2027, representing a CAGR of -0.8%. DTE Electric's bundled peak demand declines to 10,036 MW in 2027, representing a CAGR of -0.8% (Leuker, 5T 2532; Exhibit A-15, Schedule E2, pages 1 and 2).

33.59 mills per kilowatt-hour at the sales level as reflected on Exhibit A-13, Schedule C-4. Mr. Willis explained that the 7.46% loss factor is the average difference between annual system output and sales over the last five years (2017 through 2021) as shown on Exhibit A-13, Schedule C4.1, which is the method that the Commission approved in Case No. U-20836. The Company does not project any PSCR over or under-recovery in this case. The Company's proposed rates reflect the 33.59 base, and the Company used a zero PSCR factor to calculate revenues for the projected period. (Willis, 5T 3180-82).

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 \$1,290.0 million of adjusted O&M in 2021, which was projected to increase to \$1,302.4 million in the projected test period (Exhibit A-13, Schedule C5, line 12, columns (f) and (l)), the Company's projected O&M has been adjusted by a \$6.3 million reduction to Tree Trim Surge O&M Savings, a \$6.8 million reduction to Uncollectible Expense, a \$0.02 million reduction to Corporate Membership Fees, and a \$0.3 million elimination for Regional Relations labor resulting in \$1,289.0 million⁷⁴. (See Attachment A, page 3 of 4).

1. Inflation

Company witness Uzenski calculated inflation rates of 3.6% for 2022, 3.2% for 2023, and 2.66% for January 1 through November 30, 2024, 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

⁷⁴ The Company identified \$324,000 of Regional Relations expense reflected in its projected O&M that should have been eliminated. The Company has reflected the error as a reduction in the Company's updated revenue requirement amount (See Attachments A & B).

(CPI)-Urban for non-labor costs. (Uzenski, 5T 1502). Company witness Cooper further explained that he conservatively estimated annual wage increases of 3.0% for 2022, 2023, and 2024, 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 (5T 1374).

The Commission previously adopted the Company's proposed composite inflation rates (Case No. U-20836 Order dated November 18, 2022, p. 258). The record in the instant case similarly reflects that the Company's labor costs are driven by collective bargaining agreements with unionized employees, as Mr. Cooper testified:

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. [5T 1374.]

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 March 2023 that resulted in an overall pay increase of about 3.0%, just as it was in 2021 and every year since 2010. Employees also receive pay increases based on promotions (Cooper, 5T 1374).

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. Therefore, the Commission should approve DTE Electric's proposed composite inflation rate.

ABATE witness York proposed "reflecting adjustments of 0.2% per year relative to DTE adjusted actual 2022 O&M expense . . . [which] reflects a total reduction to DTE's claimed revenue

requirement of \$114.551 million” (4T 1117). The Company disagrees because witness York simply interpolated between starting and ending points over a five-year period without regard to yearly variability in the data or recent conditions. The projected CPI-U for 2023 was 4.2% when this case was filed (and was also projected at 4.2% as reflected in rebuttal), which would be the third highest CPU-I in the last 30 years (the highest was 2022, with a CPI-U of 8.1%). Witness York’s methodology ignores the current high-inflationary environment in which the Company is operating, and further lacks credibility because it is inconsistent with her own use of projected CPI increases in Case Nos. U-20561 and U-20836 (which would produce a higher inflation rate than the Company requests using its consistent methodology). Therefore, the 0.2% O&M escalator should be rejected as unreasonable due to current inflationary pressures, and the Commission should adopt the Company’s proposed composite inflation rates as it did in Case No. U-20836 (Crozier, 5T 2220-21).

2. Energy Supply (Exhibit A-13, Schedule C5, lines 1, 3 and 4; Schedules C5.1 Revised, 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 Revised, C5.4, and C5.5 (Morren, 5T 2363). Mr. Morren explained the major line items and adjustments (5T 2363-72). Steam Power Generation adjusted O&M (*including* Fuel Supply and MERC fuel handling as described below) was \$239.9 million in 2021, and is projected to be \$219.5 million in the projected test year (Exhibit A-13, Schedule C5.1 Revised, page 1, line 19, columns (g) and (m)). Hydraulic Power Generation adjusted O&M was \$9.6 million in 2021, and is projected to be \$10.6 million in the projected test period year (Exhibit A-13, Schedule C5.4, line 17, columns (e) and (k)). Other Power Generation

adjusted O&M was \$18.8 million in 2021, and is projected to be \$29.2 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 (Morren, 5T 2373).

The Company's O&M projections include a normalization adjustment for the North Area periodic outage spend (Exhibit A-13, Schedule C5.1, page 1, note 6). Staff recommended that the Company's \$11.5 million adjustment be reduced to \$2.6 million, stating "Staff found that DTE Electric spent less than average in 2021 at its Belle River and Greenwood plants, but it spent more than average at its Monroe plant. When Staff included the Monroe plant in the 2017 to 2020 average, the periodic average was reduced to \$2,599,978 after inflation as shown on Exhibit S-21.6 page 6" (Kindschy, 7T 4516-17).

The Company disagrees with Staff's inclusion of Monroe (a South Area plant) in its calculations. The Company did not include Monroe because a major Monroe periodic outage was included in both the historic and projected test years. Thus, the Company's adjustment just concerns North Area plants. Staff's inclusion of Monroe in its calculations is particularly inappropriate because Monroe did not have a periodic outage in 2020 due to COVID-19 concerns. Calculating a four-year average with what is effectively three years of data mathematically results in a lower number, but its methodology is unsound. By neglecting the COVID-19 anomaly, Staff's inclusion of 2020 Monroe periodic outage values in its 2017-2020 calculations effectively assumes that a pandemic will occur every four years and require Monroe periodic outages to be deferred by a year. Staff also included 2018 periodic outage expenses for Belle River and Greenwood. The Company's calculation appropriately did not because Belle River did not have a periodic outage in 2018, and Greenwood had only a very small, planned outage. There typically is one major periodic outage per

year at the North Area plants. Therefore, 2018 actual O&M expenses would be an improper representation for yearly periodic outage spend. The Company's future projections further support the Company's requested recovery. For all of these reasons, Staff's proposed periodic O&M adjustment should be rejected (Morren, 5T 2425-27).

**3. Fuel Supply and Midwest Energy Resources Company (MERC)
(Exhibit A-13, Schedule C5, line 2; Schedule C5.2)**

Mr. Milo supported DTE Electric's Fuel Supply and Midwest Energy Resources Company (MERC) O&M expense of \$7.3 million in 2021, and projected to be \$8.0 million in the 12-month projected test period ending November 30, 2024 (5T 2544, 2549-50; 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 2021 expenses adjusted for inflation and those expenses should be determined to be reasonable and prudent (\$4.4 million for Fuel Supply and \$3.6 million for MERC, as shown on Exhibit A-13, Schedule C5.2, column (l), lines 7 and 15) (5T 2549-50).

4. Nuclear Power (Exhibit A-13, Schedule C5, line 3; Schedule C5.3)

Mr. Davis supported Fermi 2's 2021 actual, as well as projected, nuclear O&M expenses through November 30, 2024 (5T 2436). Actual O&M expenses for 2021 were \$206.5 million (Davis, 5T 2484; Exhibit A-13, Schedule C5.3, page 1, line 24, column (c)). Three adjustments are necessary. First, column (d) reflects a \$27.4 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. Third, column (f) reflects a \$0.1 million reduction to normalize 2021 actual PERC O&M expenses to the \$15.0 million PERC O&M base (Davis, 5T 2484-86). Adjusted O&M expenses for 2021 were \$179.0 million (Exhibit A-13, Schedule C5.3, page 1, column (g), line 24), and were used to forecast projected O&M expenses through November 30, 2024. Mr. Davis explained various O&M expenses and adjustments, and testified that \$177.0 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, 5T 2484-85, 2497; Exhibit A-13, Schedule C5.3, page 1, line 24, column (n)).

The total PERC expense for the projected test period is forecasted at \$22.8 million (Exhibit A-13, Schedule C5.3, column (n), line 23). PERC expenses over or under \$15.0 million are deferred. The Company spent \$15.1 million on PERC projects in 2021, and expects to spend \$18.6 million in 2022, \$14.4 million in 2023, and \$24.5 in 2024 (Exhibit A-13, Schedule C5.16). Exhibit A-13, Schedule C5.17 shows the derivation of the PERC amortization (Davis, 5T 2492-93).

In Case No. U-20836, AG Witness Coppola proposed that DTE Electric not start the Extended Power Uprate (EPU) Study in 2023, and to remove the associated 2023 PERC O&M EPU expenditures of approximately \$4.9 million, reasoning that the “Company has not made a compelling and convincing case that the study would lead to an outcome that would provide a competitive cost of adding capacity even after considering that the added capacity would be carbon free.” (U-20836, 8T 4856). The PFD agreed with the AG (Case No. U-20836, PFD, p 532). The Commission also agreed (Case No. U-20836 Order dated November 18, 2022, p. 306). Attorney General Witness Coppola has renewed his objection and again recommended that the Commission reject the Company’s EPU proposal in its entirety. (6T 3769-3771)

Mr. Davis responded to the AG's proposed disallowance in the instant case by explaining that the requested capital expenditures for the EPU Study (\$4.9 million in 2023 as shown at Exhibit A-13, Schedule C5.15, page 1, line 18) are to provide a detailed feasibility, scoping and estimating analysis, regarding the potential for Fermi 2 to support an EPU, which would potentially yield an additional 172 Mwe of carbon-free, resilient, baseload generation capacity. The only variable O&M cost associated with this additional 172 Mwe is the cost of nuclear fuel, which could result in significant PSCR savings for DTE Electric customers. The EPU Study would also provide the Company with an improved understanding of the operational considerations required to operate Fermi 2 at EPU conditions, and narrow the uncertainty of scope and expenditures associated with the work that would be required to complete an EPU, which is a reasonable and prudent approach (Davis, 5T 2495-2497).

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

5. Distribution (Exhibit A-13, Schedule C5, line 6; Schedule C5.6 Revised)

Distribution Operations' O&M expenses are driven primarily by day-to-day trouble and storm restoration, tree-trim work, and other system maintenance requirements. (Robinson, 5T 2696). The Company originally projected \$349.0 million of O&M expenses for the projected test period ending November 30, 2024 (Miller, 5T 2840; Exhibit A-13, Schedule C5.6, p 1, line 27, column (I)), which was later revised to \$344.4 million as shown on Exhibit A-13, Schedule C5.6 Revised. The forecast is based on actual 2021 O&M expenses, normalized and adjusted. Mr.

Robinson explained and justified significant components and adjustments underlying the projected O&M costs, as reflected on Exhibit A-13, Schedule C5.6 Revised, and supported the actual and projected O&M costs as reasonable and prudent (5T 2696-2701).

i. Inflation

MNSC witness Ozar proposed that the Commission “reject DTE’s inflation adjustment, in the amount of \$17,830,000” associated with restoration O&M expenses, asserting that “[i]t is unjustified for DTE to include an adjustment for inflation and not an offsetting adjustment for distribution system reliability productivity, while in the same proceeding request hundreds of millions of dollars in incremental surge trimming and strategic investments that the Company claims will improve reliability (and by extension reduce Restoration O&M).” (Ozar, 6T 3573).

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

ii. Tree Trimming

In DTE Electric’s previous rate case:

The ALJ noted that “[n]o p[arty] disputed DTE [Electric]’s tree trimming expense or its surge program spending plan.” PFD, p. 473. The Commission approves 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. [Case No. U-20836 Order dated November 18, 2022, p. 261.]

The Company now seeks base O&M funding of \$106.4 million for 2024, which is the base O&M funding from Case No. U-20561 plus inflation (Hartwick, 5T 2142, 2145; Exhibit A-22, Schedule L1, page 1, line 17).⁷⁵ The Company also requests surge funding of \$43.7 million in 2025 (Hartwick, 5T 2142; Crozier, 5T 2185; Exhibit A-13, Schedule C5.6.1). In Case No. U-20836, the Company did not request surge funding for 2025 because the Company was *targeting* to complete the surge program by the end of 2024, which is one year earlier than previously proposed in Case Nos. U-20162 and U-20561, due to the Company's additional funding as discussed in the Company's application in Case No. U- 21128. Due to revised cost projections, the Company is committed to complete the surge in 2025 (Hartwick, 5T 2142).⁷⁶

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. (Case No. U-17542 Order dated May 2, 2014, p. 16; Case No. U-17542 Order dated December 4, 2014, 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 removes vegetation in a clearance corridor rather than the historic clearance circle around DTE Electric's lines and equipment. The Commission approved the ETTP

⁷⁵ The base tree-trimming O&M includes the Company's spending on the herbicide program as outlined in previous rate cases. The herbicide program is based on industry best practices, and uses EPA-regulated herbicides to replace mechanical removal of vegetation from the right-of-way. The targeted chemical treatment controls the tree species with the potential to grow into electrical wires, but does not affect grasses and shrubs. The herbicide treatment will reduce the cost of maintaining trimming in the right-of-way by reducing tree density, which will reduce overall trimming costs (Hartwick, 5T 2156-57).

⁷⁶ Ms. Hartwick discussed resources needed to complete the surge by the end of 2025, including the number of tree trimmers that are needed, the risks to maintaining and growing the current level of tree trimmers, and the Company's efforts to grow the local work force (5T 2146-49).

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 (Case No. U-18255 Order dated April 18, 2018, 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 (Case No. U-20162 Order dated May 2, 2019, 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" (Case No. U-20561 Order dated May 8, 2020, pp. 208-209). In Case No. U-20836, tree trimming expense was uncontested, and the Commission approved additional surge funding through 2024, as indicated above.

Against this background, Company witness Hartwick testified that in 2021, DTE Electric (1) trimmed 5,747 line-miles on 721 circuits (less than the planned 6,156 miles); (2) completed 23,784 tree trim comparable units (exceeding the 23,524 target); and (3) spent \$140.2 million on line clearance maintenance costs. The Company planned to trim 6,300 miles in 2022 (553 more miles than in 2021) and exceeded this goal by trimming 6,700 miles. The reason for these differences is that the model used for the Company's estimate in Case No. U-20836 was based on an average mile (average density and average complexity). When developing a plan for each year, the Company prioritizes circuits based on reliability impacts and wire down reductions. The difference in miles trimmed as compared to plans was driven by the Company reprioritizing circuits in response to the severe storms in 2021. Most of these circuits are located in vegetation dense areas with majority backlot work (Hartwick, 5T 2118-20).

The ETTP is a well-designed program with proven success and continuing importance. Circuits trimmed as part of the ETTP have a 69.1% reduction in outage events in the year after

trimming compared to non-ETTP trimmed circuits. ETTP-trimmed circuits similarly showed reductions of 73.9% in customer interruptions, 66.7% in the number of customer minutes of interruption, and 35.2% in wire-down events in the year following trimming, compared to non-ETTP circuits (Hartwick, 5T 2122-26).

The surge program needs to continue because, as discussed in the Company's Grid Distribution Plan in Case No. U-20147, tree interference is the leading driver of customer outages. Tree-caused outages account for two-thirds of the time that customers spend without power (Hartwick, 5T 2127-28).

The tree trimming program should be funded to maintain a trimming cycle where circuits are re-trimmed before the trimmed trees grow back into the Company's wires and become hazards. The Company remains firmly committed to achieving a five-year trimming cycle for distribution circuits (three years for sub-transmission circuits because of the high customer impact of trouble events on these circuits). Assuming an average mile, a five-year cycle requires trimming approximately 6,538 miles per year. The five-year cycle was determined because (1) trees near the Company's distribution equipment grow approximately 10 feet in five years, and (2) the five-year cycle provides a reasonable and acceptable level of tree-to-conductor contact (the likelihood of any portion of a tree touching a conductor) comparable to the industry average standard of 10% to 15%. The Company's targeted five-year cycle is also comparable to the industry average of 4.9 years (Hartwick, 5T 2127-32).

Reducing the tree-trimming cycle to five years will provide multiple customer benefits and savings including: (1) fewer wire down events, resulting in improved safety; (2) fewer outage and non-outage events, leading to improved reliability and a positive impact on reactive O&M and capital costs, as well as the re-allocation of resources to other necessary work across the distribution

system; (3) lower customer complaints from tree-related events; (4) lower future tree-trimming costs; and (5) lower customer costs as tree-related outages are reduced (Hartwick, 5T 2133-34).

Ms. Hartwick explained:

The tree trimming program is the most impactful and important program in the Company's long-term investment strategy. The program has shown that it significantly decreases system risk (specifically reduced wire downs), increases reliability (fewer and shorter outages), and will decrease reactive trouble costs. The tree trimming program as proposed is required to provide safe, reliable and affordable electricity to the Company's customers. Without continuing the Surge investment, the distribution system will continue to degrade, resulting in higher costs and lower reliability [5T 2159.]

Ms. Hartwick also testified that her opinion is based on analysis of past expenses, and the projected requirements for labor and materials to conduct the necessary tree trimming (5T 21590). A net present value (NPV) analysis further indicates that continued execution of the surge is \$71.2 million favorable to customers as compared to just the baseline O&M tree trimming without the surge funding (Hartwick, 5T 213422; Exhibit A-22, Schedule L1, pages 3 and 6).

The idea of variable cycles was raised by intervenors in Case No. U-20836, and the Commission ordered: "In its next general rate case, DTE Electric Company is expected to provide an update on its analysis regarding its tree trimming program, including improving efficiency and evaluating potential future benefits from utilizing a variable cycle" (Case No. U-20836 Order dated November 18, 2022, p. 487).

Accordingly, Ms. Hartwick further explained that once the surge is completed (bringing all circuits up to a five-year cycle), the Company may elect for a risk-based, variable maintenance schedule. The Company has identified LiDAR (light detection and ranging)⁷⁷ as an emerging best practice and valuable tool for vegetation management. Beginning in 2021, the Company invested

⁷⁷ 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 (Hartwick, 5T 2150).

in LiDAR collection and processing for the entire electrical territory. The Company has already leveraged the LiDAR data, for example as part of the 2023 pricing negotiations with tree-trim contractors. The Company is currently developing a risk-based, variable cycle model that will leverage the LiDAR data to help identify optimal trim cycles and emerging hot spots. The model will also provide key improvements for the Company's annual negotiations with tree trimmers (Hartwick, 5T 2128, 2149-54, 2156).

The Company recognizes that a standard five-year cycle might no longer be optimum for the system once everything is trimmed to the same specification and considered on-cycle. The Company believes that adjusting cycle-lengths based on species growth rates, risk of outages, and cost of trimming will further improve trimming efficiencies and provide reliability benefits to customers. The LiDAR and tree species data that the Company has recently acquired give it the information necessary to refine the program with data-driven improvements. Based on the benchmarking of other utilities, the Company anticipates the need to trim high-risk areas more frequently, and low-risk areas less frequently, resulting in overall reliability benefits and a more efficient use of resources, with an annual cost reduction of approximately 5% related to optimizing resources. To understand the benefits, and potential tradeoffs, the Company intends to pilot risk-based cycles in several areas prior to moving to this type of maintenance cadence (Hartwick, 5T 2151-54; Exhibit A-22, Schedule L2, line 5).

The Company seeks to recover the \$6.3 million direct capitalization investment for its Tree Trim Risk Prioritization Model (Hartwick, 5T 2155; Exhibit A-12, Schedule B5.4, page 12, line 8).⁷⁸ The NPV for the model is \$11.2 million (Hartwick, 5T 2155; Exhibit A-22, Schedule L2).

⁷⁸ In addition, the Company's Digital Infrastructure and Services Team supported the development of the model. The capital investment for this effort is \$8.3 million (Hartwick, 5T 2155).

The Company proposes to defer surge costs up to \$163.4 million above base rates from 2023 through 2025 (Exhibit A-22, Schedule L1, page 1, line 12, columns c-f). 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 (Hartwick, 5T 2145-46; Crozier, 5T 2186). A securitization filing capturing costs through 2023 is technically feasible in 2024, but since the remaining 2024 and 2025 expenditures are not anticipated to attain the required scale needed for a standalone filing, 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. (Crozier, 5T 2187).

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 was temporary in light of the Company's contemplated securitization filing (Case No. U-20162 Order dated May 2, 2019, p. 80).⁷⁹ This treatment was continued in Case Nos. U-20561 and U-20836. Exhibit A-11, Schedule A1.1 identifies the \$8.6 million return on the tree trim surge regulatory asset for the projected test period using this same methodology (Vangilder, 5T 2596).⁸⁰

⁷⁹ 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.

⁸⁰ The Company calculated a return based on the short-term interest rate to reduce the number of contested issues in this case, 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 (Crozier, 5T 2186-87, 2238; Lepczyk, 5T 3274-75).

In compliance with the Commission’s reporting requirements (Case No. U-20162 Order dated May 2, 2019, p. 81; Case No. U-20561 Order dated May 8, 2020, p. 208), the Company has provided reports and will continue to provide reports until the surge program is complete (Hartwick, 5T 2157).

AG witness Coppola recommended that the Commission “remove \$15.9 million in cost savings from the Company’s forecasted O&M expense” due to savings from the surge (6T 3775). The \$15.9 million includes three expense items: (1) Tree Trim Reactive, (2) Tree Trim Storm, and (3) Dist. Ops. Storm & Trouble. The Company disagrees with the AG regarding Tree Trim Reactive because the savings are already accounted for in Exhibit A-22, Schedule L1, line 4. The Company agrees with the AG that O&M should be reduced by savings from Tree Trim Storm (\$3.6 million) and Dist. Ops. Storm & Trouble (\$2.7 million). These items were inadvertently omitted from the O&M calculation, and this has been corrected by a \$6.3 million O&M reduction (Hartwick, 5T 2162-63; Exhibit A-13, Schedule C5.6 Revised, page 1, line 20).

MNSC witness Ozar recommended that the Commission order the Company to “include an action plan in its next general rate filing” for a “pre-emptive service line tree maintenance program” (6T 3584).⁸¹ Staff recognized that “tree trimming around residential service drops is the responsibility of the customer,” but suggested: “It may be beneficial for the Company to take responsibility for service drop tree trimming. Staff recommends DTE develop a proposal for a

MNSC witness Ozar’s unsupported comment that the Commission “could consider not approving any return” on the Company’s regulatory asset (6T 3590) is unreasonable and otherwise lacks merit, particularly since the regulatory asset has allowed the acceleration of tree trim work that benefits customers, and prevents the rate shock that would otherwise occur if the costs were treated as O&M expenses (Crozier, 5T 2238). See also section IV above.

⁸¹ A “service drop” is generally the term used for an overhead secondary conductor running from a utility pole, across a customer’s property, to a meter installed on a house (for a typical residential customer). Utilities typically have a right-of-way (ROW) that allows them to trim vegetation surrounding their wires running from pole to pole. The Company does not have the same ROWs for service drops (Hartwick, 5T 2163).

residential service drop tree trimming pilot [including] the estimated costs for the pilot and a good area of their service territory in which to conduct it” (Duell, 7T 4402).

These suggestions are not reasonable and prudent at this time. The Company understands the underlying concerns and would consider pilots in the future. Before initiating a pilot, however, the Company would need to conduct a study to estimate the scope, cost, resources required, and projected reliability improvement. That would be a significant task. Benchmarking indicates that other utilities do not perform service drop trimming, so there is little, if any, industry data available regarding service drop trimming (Hartwick, 5T 2164).

MNSC witness Ozar further suggested that DTE Electric provide capital and O&M information regarding service line restorations (6T 3592). To the extent that the Company does not already report this information, the Company does not agree with the suggestion to add an additional de facto rate case filing requirement (Hartwick, 5T 2165). The Company further objects to MNSC first making this suggestion in revised testimony filed on July 3, 2023, which was well after the June 13 deadline for intervenor testimony, and just before the July 7 deadline for rebuttal.

Ann Arbor witness Stultz suggested that the Commission should create a tracker to confirm that revenues approved for tree trimming are spent on tree trimming (4T 876). The Company disagrees because the proposed tracker would be redundant. The Company’s tree trim surge deferral only receives recovery on the dollars above what is in O&M if those dollars are spent on tree trimming. The Company also already submits a detailed annual report on tree trimming activities including a breakdown of expenditures (Hartwick, 5T 2165).

Therefore, the Commission should adopt the Company’s tree-trimming requests and reject all contrary and additional proposals.

iii. Community Lighting (Exhibit A-13, Schedule C5.6 Revised, line 23)

DTE Electric's Community Lighting O&M expenses for street lighting and signal systems are held steady at the 2021 historical level of \$5.2 million, adjusted only for inflation, resulting in a forecasted O&M expense of \$5.7 million in the projected test year (Bellini, 5T 2636; Exhibit A-13, Schedule C5.6 Revised, line 23).

The Company's preventative maintenance programs include LED washing and group relamping. In accordance with the Commission's prior decision on LED washing (Case No. U-20836 Order dated November 18, 2022, p. 267), the Company will adopt a 10-year LED washing cycle that will take effect in 2023. (Bellini, 5T 2623).

MI-MAUI witness Bunch proposed \$0 for LED washing (a \$384,487 disallowance) apparently reasoning that no LEDs should need to be washed on a 10-year cycle (4T 922-24). The Commission should reject this disallowance because the cost is for luminaires that are slated for washing during the projected test year, and are reflective of the number of LEDs that were originally installed in 2014. There are also LEDs that fell behind the washing cycle due to the lack of crew availability during the COVID-19 pandemic and the severe storm seasons of 2021 and 2022 (Bellini, 5T 2663). Therefore, the Company's \$384,487 request should be approved.

MI-MAUI witness Bunch proposed that the Commission "approve total spending on Supervisory and Administrative staff in the projected test period of \$1,279,807" (4T 925), which is a \$1,328,358 disallowance. The Company maintains that its request is reasonable considering (1) the increase in these costs is attributable to new positions that are critical to effective management of the Company's streetlighting program (Exhibit A-40, Schedule EE8); (2) the streetlighting team headcount has steadily declined from 2018 – 2023 (Exhibit A-40, Schedule EE9); and (3) inflation. Witness Bunch's reasoning that "an annual increase of greater than 10% is likely unrealistic and

unjustified” (4T 925) is also speculative and arbitrary, so it cannot support a decision.⁸² Therefore, the Company’s \$2,608,165 request should be approved. (Bellini, 5T 2664).

MI-MAUI witness Bunch asserted a need for, “Much better communication of energy infrastructure project planning to support coordination of scheduling with municipal and other infrastructure projects, reducing overall costs and inconvenience to community members.” (4T 902). The Company agrees that better communication and coordination is needed regarding streetlighting, but this is a collaborative effort, and not just the Company’s responsibility. The Company’s streetlighting work generally falls in two categories: (1) planned work (conversions and new installations), and (2) reactive maintenance. The Company keeps its municipal customers apprised regarding planned work. There are gaps in communications regarding streetlighting outages (reactive maintenance) caused by third-party excavation work. The Company often responds to underground-related damages caused by third parties. There are two key ramifications (1) the damages tend to result in multiple outages that are long in duration and tend to be complex and, depending on the municipality, may require permits, and (2) they are costly (Bellini, 5T 2650-51; Exhibit A-40, Schedule EE1). Therefore, to improve collaboration with municipalities and reduce underground infrastructure damage, the Company recommends that municipalities: (1) require third-party excavators to provide notice to the municipality and utilities that work will be

⁸² 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).

occurring at or near critical infrastructure, (2) put third-parties on notice that they may be held responsible for repair costs if they damage infrastructure, and (3) do not let repeat offenders continue to perform work unless and until they are able to demonstrate due diligence (Bellini, 5T 2651-52).

MI-MAUI witness Bunch also cited metrics indicating longer-duration outages (approximately 1.1 days in 2022 vs. 2017), and asserted that “despite all of the spending, things have only gotten worse” (4T 905). The Company disagrees because there are factors beyond the Company’s control such as (1) a lack of special-order materials (SOM) maintained by municipalities that impede the Company’s ability to respond, and (2) limited availability of street light construction crews during storm restoration events, including the severe storm season in 2022 (Bellini, 5T 2652; Exhibit A-40, Schedule EE2).

Witness Bunch further asserted: “In 2017, DTE reported a total of 20,670 streetlight outages, and in 2022 it reported 19,730 outages – approximately a 4.5% drop” (4T 905). He then disregarded this data and applied unjustified assumptions to suggest that the decrease is actually an increase: “Assuming outages discovered in night patrol would eventually have been reported by citizens or government (as in 2017), reliability has actually gotten noticeably worse, with a total outage number in 2022 of 24,415 – an outage increase of 16% in five years” (4T 905).

This reasoning lacks merit for three reasons. First, the night patrol program started in 2019, not 2017, so the baseline is incorrect. Second, the suggestion that the outages discovered by the night patrol would have eventually been otherwise reported is contrary to Mr. Bunch’s own prior testimony in Case No. U-20836. Third, an apples-to-apples comparison of performance metrics excluding night patrol shows that customer-reported outages decreased from the end of 2019 (when

the night patrol pilot began) through 2022 by 16% (Bellini, 5T 2653-54; Exhibit A-40, Schedule EE3).

6. Customer Service (Exhibit A-13, Schedule C5, line 7; Schedule C5.7)

Mr. Sparks supported the actual and projected O&M expenses for the Customer Service organization as reasonable and necessary (5T 1444-61; Exhibit A-13, Schedule C5.7).⁸³ These O&M expenses (including rate case adjustments) were \$108.7 million for the 2021 historical test period, and are expected to increase to \$114.5 million for the projected test year (Sparks, 5T 1444, 1460-61; Exhibit A-13, Schedule C5.7).

Mr. Sparks discussed the Customer Service organization's work activities performed in 2021 (5T 1450-60), and testified that the projected O&M increase is based on continuing those activities, with (1) inflation adjustments of \$3.3 million for 2022, \$3.1 million for 2023, and \$2.4 million for January 1, 2024 through November 30, 2024,⁸⁴ (2) a known and measurable adjustment for fees paid to process credit card payments (merchant fees) of \$(1.7) million, (3) other adjustments including Customer Records and Collection Expenses of \$(4.5) million, and (4) ACPP / Time of Use Reg Asset Amortization of \$3.0 million (Sparks, 5T 1460-61). (With respect to Merchant Fees, see Peterson, 4T 782-84; Exhibit A-13, Schedule C.5.7.1, page 1, column (g), line 5; Maroun, 5T 3145).

⁸³ 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. (Sparks, 5T 1446-49).

⁸⁴ The rate of inflation is 3.6% for 2022, 3.2% for 2023, and 2.66% for the first 11 months of 2024 (Uzenski, 5T 1502; Exhibit A-13, Schedule C5.15, line 15).

7. 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 \$54,614,000 of uncollectible expense based on a three-year average of actual uncollectible expense for 2019-2021, (Griffie, 5T 2097-99; Exhibit A-13, Schedule C5.8, page 1, line 1, column (e)), but now agrees to \$47,855,000 as discussed below.

Staff proposed a \$12,654,000 downward adjustment (from \$54,614,000 to \$41,960,000) (Rueckert, 7T 4673; Exhibit S-8.0). The AG proposed an \$8.7 million reduction to \$45.9 million (Coppola, 6T 3776-77). Both proposals are based on using the cash-basis method for estimating uncollectible expense. The Company agrees that it was appropriate for the Staff and AG to update the calculation to include the most recent three-year average of write offs (2020-2022), and in light of the Commission's prior orders adopting the cash-basis method, does not dispute its use (Griffie, 5T 2105-2106).

With that said, two changes are required for Staff's calculation: (1) the historical write-off ratio should be applied to proposed revenue instead of present revenue, and (2) Non-Energy Net Write-Offs should not be excluded from the calculation. Both of these changes are consistent with AG witness Coppola's calculation in Case No. U-20836, which the Commission adopted. Similarly, the AG's calculation in this case should be corrected so that uncollectible expense includes direct charges relating to the Company's matching of Low-Income Home Energy Assistance Program (LIHEAP) support, which is consistent with Staff's calculation. Thus, as corrected, both the Staff's and AG's projections are \$47,855,000, which the Company does not dispute (Griffie, 5T 2105-2106).

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

The AG asserted that the Company does not comply with Billing Rules 460.111(15) and 460.112(1). (Bunch, 6T 3609-12). Rule 460.111(15) states that a "utility shall provide to any person who objects to paying a deposit information on the process to contest the deposit requirement." The Company fully complies with this rule (which does not specify what is required), but recognizes an opportunity to provide enhanced messaging to customers, and will do so. The Company recognizes that it has a deficiency with Rule 460.112(1) (referring to having a written guarantee that states all terms of the guarantee) and is working to implement the written guarantee (Griffie, 5T 2108-2109).

The AG further suggested that the Commission should order DTE Electric to stop requiring cash payments from customers whose payments are dishonored or returned, and to change the tariff language that allows this practice (Bunch, 6T 3612). The Company disagrees because section C4.6 of the Company's rate book for electric service is a longstanding and appropriate provision (Griffie, 5T 2109-10). The Company also complies with the billing rules, as Mr. Bunch acknowledges in asserting that the Commission should change the rules. Even if there were a basis to change the

rules (which there is not), this is not a proper forum to do so.⁸⁵ It would also be improper for the Commission to order the Company to not do something that is allowed by the rules.⁸⁶

8. Regulated Marketing (Exhibit A-13, Schedule C5, line 9; Schedule C5.9)

Regulated Marketing had \$20.8 million of O&M expense for the 2021 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 (Peterson, 4T 786-87).

DTE Electric seeks to recover \$32.7 million in the projected test year (Exhibit A-13, Schedule C5.9, column (k), line 15). Mr. Peterson outlined the known and measurable changes to the historical 2021 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 regulated Company offerings (Peterson, 4T 787-89).

⁸⁵ *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002)

⁸⁶ 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”).

9. 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 \$196.2 million for the 2021 adjusted historical test period, and are expected to increase to \$213.3 million for the projected period ending November 30, 2024 (Uzenski, 5T 1513-16; Exhibit A-13, Schedule C5.10, line 20, 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, 5T 1516-18).

i. IT O&M Disallowances

For convenience and continuity of discussion, IT O&M is addressed here with other IT issues (although the overall discussion concerns capital expenditures), due to the nature of Staff's proposals.

Staff proposed a \$5.2 million O&M reduction relating to capital expenditures that it proposes to disallow (\$4.2 million for projects with Level 2 cost estimates, and \$1 million for individual projects). (Rogers, 7T 4661-62). In addition to the discussions that capital expenditures should be approved, the Company disagrees with Staff's \$5.2 disallowance because Staff's proposed IT O&M reductions were not included in the Company's requested revenue deficiency. Instead, the Company's projected O&M is included in Administrative and General expense, and uses 2021 historical expense and adjusted only for inflation (Uzenski, 5T 1519, 1564, 1567; Exhibit A-13, Schedules C5.10, page 1, line 3, column (j)).).

If the Commission were to decide to disallow any O&M expenses, then that disallowance should be reduced to the portion that applies to DTE Electric only. The \$5.2 million O&M cited by Staff is the amount supporting all users⁸⁷ of the assets. The IT O&M costs recorded at DTE Electric are based on the bill down of costs from the DTE Energy Corporate Services, LLC, or about 75% of the total (\$3.2 million), as reflected by Exhibit A-36, Schedule AA1, line 21, column (g). Therefore, if the Commission disallows any O&M related to these IT projects, the amount should be calculated in accordance with column (g). (Uzenski, 5T 1564-65, 1567-68).

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

IT O&M expense consists of some expenses related to project work along with on-going and base operating expense not tied to specific projects, which includes cloud computing fees, software as a service, hardware and software defect remediation, business support services, and IT administration. The Company's 2021 historical IT O&M including both project work and base operating expenses was \$63.0 million as reflected in the historical data provided in the current case. The Company just added inflation to this historical expense, resulting in its \$69.1 million projection. Without funding for base operating IT O&M, the Company would not be able to run and maintain existing IT systems, which would impair the Company's ability to operate effectively in delivering safe and reliable service to customers. Importantly, approximately 35% of the projected IT expense

⁸⁷ DTE Gas Company and DTE Electric Company.

is for payroll for IT staff who support daily operations. Thus, the Company appropriately calculated its projected expense as historical actual costs plus inflation, and Staff's proposed disallowance should be rejected. (Uzenski, 5T 1518, 1564, 1568-69).

ii. Shared Asset Revenue

The Company forecasted \$60.1 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, 5T 1570; Exhibit A-36, Schedule AA1).

iii. Corporate Memberships

In the Company's last general rate case, the Commission "direct[ed] DTE Electric to file in its future rate cases an exhibit containing an itemized list of projected costs associated with membership fees and justification for why these costs are in customers' interest" (Case No. U-20836 Order dated November 18, 2022, p. 308). Ms. Crozier responded by explaining that the Company acquires and maintains corporate memberships that help in its mission to provide safe, affordable, and reliable energy. Exhibit A-27, Schedule Q1 includes the costs and a description for each corporate membership included in DTE Electric's O&M expense for the projected test year. Pages 1-2 of Exhibit A-27, Schedule Q1, display the memberships that are non-discretionary. Pages 3-7 of Exhibit A-27, Schedule Q1, display the memberships that are discretionary. The descriptions include the benefits of the memberships. Also, corporate memberships that are non-discretionary and exceed \$100,000 are further supported by other witnesses representing the primary business

unit that utilizes the membership. Exhibit A-27, Schedule Q1 provides the witness names and associated business units (Crozier, 5T 2187-89).

For example, Company witness Morren, representing Energy Supply, described the benefits that the Company realizes through its memberships in industry associations, such as the Electric Power Research Institute (EPRI), and the Low Carbon Resource Initiative (LCRI), which is a five-year joint effort between EPRI and the Gas Technology Institute (GTI) aimed at accelerating the development and demonstration of low and zero-carbon energy technologies (Morren, 5T 2368-69).

Staff proposed a \$0.6 million disallowance for the LCRI membership (McMillan-Sepkowski, 7T 4581). The Company disagrees because the costs to perform even one of the EPRI projects would be greater than the cost of membership. Following guidelines offered by EPRI also protects power plant equipment and maintains reliable operations. The economics of membership and customer benefits apply equally to the LCRI. Moreover, participating in initiatives where the Company can learn from industry partners and projects in other service territories is a critical step in advancing emerging technologies that will support the net-zero goals set by the Company and the MI Healthy Climate Plan (Morren, 5T 2368-69, 2428-29).

Ms. Crozier further explained that in addition to the Company's operating groups, the Company leverages Edison Electric Institute (EEI) to benefit customers through many internal organizations. She also provided ongoing and recent examples of how the Company's EEI participation benefits customers (Crozier, 5T 2190-91).

In addition to the benefits included in each membership's description, the benefits that the Company and its customers receive from the memberships listed in Exhibit A-27, Schedule Q1,

pages 2-7 generally fit into one or more of the following categories: Benchmarking; Best practices; Research; and Networking (Crozier, 5T 2189-90).

The membership costs associated with the organizations listed on Exhibit A-27, Schedule Q1, and that are proposed for inclusion in rates, do not include lobbying activities (Crozier, 5T 2189-90). Ms. Uzenski further explained how certain memberships and membership costs were excluded from customer rates (5T 1490; Exhibit A-3, Schedule C14). The Company identified \$20,000 reflected in its projected O&M that should have been eliminated. The Company has reflected the error as a reduction in the Company's updated revenue requirement amount.

DAAO witness Koeppel proposed that the Commission disallow \$5.3 million in memberships in all 15 organizations presented for inclusion in the Company's revenue requirement (6T 3988-92). The Company disagrees because his claims are unsupported and contrary to the record. First, he claimed that the Company did not provide adequate evidence of ratepayer benefits (Koeppel, 6T 3998), which is contrary to the record showing benefits to customers (Crozier, 5T 2187-91; Morren, 5T 2368-69; Davis, 5T 2488-89; Exhibit A-27, Schedule Q1). Second, he placed the various memberships in tiers based solely on his subjective judgment but Mr. Koeppel, nevertheless, ultimately opposes approving *any* of the tiers (Koeppel, 6T 3989). Third, Mr. Koeppel suggested that the standard for approval should be whether the organization supports the "expansion of community-based renewable energy, electrification, and rapid climate response" (Koeppel, 6T 3990). The Company's operations, as well as its customers' interests, are far more expansive than these limited matters, and it is reasonable and prudent for the Company to participate in memberships that involve other areas. Moreover, Mr. Koeppel did not offer any explanation for his suggestion that the Commission was wrong in approving these expenses in Case No. U-20836. Instead, he only cited activities in other states (6T 3990-92) rather than any Michigan activities or

anything related to the membership dues that the Company seeks to recover. Therefore, DAAO's proposal should be rejected (Crozier, 5T 2227-28).

10. Pension and Benefits (Exhibit A-13, Schedule C5, line 11; Schedule C5.11)

DTE Electric projects \$126.017 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 \$101.995 million for the projected test year (5T 1373; Exhibit A-13, Schedule C5.11, line 28).

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 2.57% for the historical period, and 2.91% 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 2020, 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 2.91% discount rate for the projected period is based on the discount rate as of December 31, 2021.

Expected Return on Assets: This is an estimate of the expected investment return on assets invested in the pension trusts for the current period. While actual year-to-year investment returns can vary significantly, the expected return is determined based on long-term financial market expectations in order to avoid large swings in pension costs based on short-term investment performance. DTE Electric's estimated annual rate of return was 7.0% for the 2021 historical period, and is reduced to 6.8% in 2022, 6.6% in 2023, and 6.2% in 2024.

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 interest rate environment between year-end measurements, and 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 (Cooper, 5T 1349-52).

DTE Electric's annual pension costs are expected to decrease from \$95.826 million in the historical test period to negative \$7.102 million in the projected period, or negative \$3.274 million inclusive of the effects of costs capitalized and transferred, as reflected in the Company's initial filing (Cooper, 5T 1352-53; 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 (Case No. U-20836 Order dated November 18, 2022, p. 292). The Company proposes to continue the pension deferral mechanism, so the projected negative 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 (Cooper, 5T 1353; Uzenski, 5T 1503-1504).

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 Postretirement Benefit Obligation (APBO), the expected return on assets invested to meet the future liabilities, and the amortizations related to deferred gains and losses as well as prior service costs (Cooper, 5T 1354-55).

DTE Electric's OPEB costs are projected to decrease from a negative \$31.445 million in the historical test period to a negative \$36.435 million in the projected period, or negative \$21.424 million, inclusive of the effects of costs capitalized and transferred (Cooper, 5T 1356; Exhibit A-13, Schedule C5.12.2).

The Commission previously approved the Company's proposal to defer negative OPEB expense to a regulatory liability (Case No. U-17767 Order dated December 11, 2015, p. 69), and to

continue that deferral in subsequent cases. The Company proposes the continued deferral of the negative net OPEB expense consistent with prior treatment. If net OPEB expense becomes positive in the future, then the expense will be charged against the regulatory liability. Therefore, the negative OPEB expense is not included in the Company's proposed revenue requirement, and there is no obligation for the Company to fund its OPEB liability (Cooper, 5T 1356-57; Uzenski, 5T 1503-1504; Exhibit A-13, Schedule C5.12.2, line 18).

AG witness Coppola "propose[d] that the Company begin to amortize the balance of \$128,416,000 as of December 2022 over a seven-year period and include the resulting amortization expense of \$18,345,000 in the projected test year as a reduction to O&M expense" (6T 3793). The Company disagrees for two reasons. First, the inclusion of a negative cost in the Company's revenue requirement would have a detrimental impact on the Company's future cash flows since the Company's revenue and cash receipts would be reduced without any corresponding reduction in cash outlays. Second, the AG's proposal assumes a level of future expense that is difficult to forecast with any certainty, and changes in asset returns and discount rates could result in positive expense. Therefore, the Company supports a continuation of the deferral of actual OPEB expense (Uzenski, 5T 1565, 1576-77).

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. 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 New Hire VEBA expense is expected to increase from \$7.272 million in the 2021 historic test year to \$13.967 million in the projected test year, based on annual escalations of 25%. The escalation rate

is based on the Company's experience, and reflects the growth in the number of plan participants due to new hires (Cooper, 5T 1357).

Staff projected \$11.363 million (a \$2.604 million reduction) based on the 2021 expense of \$7.272 million escalated by 16.5% annually (Rueckert, 7T 4678). The Company disagrees with Staff's reasoning and result for two reasons. First, Staff relied on a prior annual increase in the Company's New Hire VEBA expense, which is an unreliable indicator of future increases in New Hire VEBA expense due to the increase in the proportion of New Hire VEBA costs capitalized in recent years. A more accurate measure of historical annual increases is the Company's total New Hire VEBA costs (prior to any adjustment for the portion capitalized), which increased at a five-year average of 20.1%, inclusive of 2020, and 23.1% exclusive of 2020 in contrast to the 16.5% used by Staff (Cooper, 5T 1421-22; Exhibit S-8.3).

Second, Staff did "not agree with the Company's reasons for excluding 2020 in its 4-year average" (Rueckert, 5T 4678). The Company disagrees because (as reflected on Staff Exhibit S-8.3) the actual increase in the Company's New Hire VEBA expense in 2020 was much lower than the increases experienced in prior years. Table 1 (Cooper, 5T 1423) shows that the net accrual for new hires increased by only 7.2% in 2020, compared to between 19.5% and 33.1% for 2017, 2018, 2019, and 2021. The decline in 2020 was largely driven by the significant reduction in new hires during the COVID-19 pandemic making the 2020 year not representative of the Company's hiring which impacted its New Hire VEBA costs. Therefore, it is appropriate to exclude 2020 from the historical average to avoid skewing the results. (Cooper, 5T 1423).

If the Commission were to disagree (which would be inappropriate), then in the alternative using Staff's Exhibit S-8.3 with one change (substituting the average of the increase in the Company's New Hire VEBA costs in 2017 through 2021, exclusive of 2020) produces an annual

escalation rate of 23.1%, and a New Hire VEBA expense of \$13.338 million for the projected test year (Cooper, 5T 1423; Exhibit A-37, Schedule BB2).

AG witness Coppola proposed a New Hire VEBA expense of \$8.4 million for the projected test year. He took the Company's 2021 actual New Hire VEBA expense of \$7.272 million and reduced it by a true-up adjustment of \$1.337 million recognized in 2022 related to 2021, to get a 2021 expense of \$5.9 million, which he then escalated by a 12.4% annual growth rate (Coppola, 6T 3782).

The Company disagrees with Mr. Coppola's reasoning on two accounts. First, like Staff, Mr. Coppola relied on historical increases in the Company's New Hire VEBA expense, which is an unreliable basis for determining future escalations because the historical expense is impacted by changes in the proportion of New Hire VEBA costs that are capitalized. Second, he used one year's true-up to adjust the 2021 expense without regard to whether the true-up for 2021 resulted in a representative level of expense (Cooper, 5T 1421 and 5T 1424).

Company witness Cooper further explained the components of the Company's New Hire VEBA costs, including the true-up that reflects forfeitures by employees who leave the Company before the end of the 10-year vesting period. An historical analysis of the Company's New Hire VEBA costs by component (Exhibit A-37, Schedule BB3) further reflects that 2021 was unusual. In addition to the decline in the number of new hires during 2020 as a result of the COVID-19 pandemic (discussed in part above), there were a significantly large number of forfeitures in 2021 as the Company realized a surge in resignations by employees who had not yet vested while the economy transitioned out of the pandemic. This drove the correspondingly large and unrepresentative 2022 true-up. Therefore, the Company's adjusted New Hire VEBA costs are

unrepresentative of future costs, and the percentage change for 2021 should be excluded from any projection (Cooper, 5T 1424-26).

However, Company witness Cooper also developed an alternative to Mr. Coppola's calculation if necessary. Starting with the unadjusted 2021 New Hire VEBA cost of \$11.793 million (excluding the non-recurring effect of forfeitures in 2021) and using an annual escalation rate of 23.9% (four-year average of the annual percentage change from 2017 through 2020) produces a projected cost of \$22.046 million, which after reduction for the portion of costs capitalized is \$14.484 million (Cooper, 5T 1426).

iv. Employee Savings Plan

The Company's Employee Savings Plan allows eligible employees the opportunity to put aside a certain percentage of their annual earnings, that 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 period pension plan closed to most new hires generally receive an additional employer contribution of 4.0% of annual salaries and wages. The Employee Savings Plan costs (Exhibit A-13, Schedule C5.11, line 5) are projected to increase from \$29.079 million in the historic test year to \$36.405 million in the projected test year, which reflects an 8.0% annual increase that is based on the Company's experience (Cooper, 5T 1358).

Staff projected \$32,257,000 (a \$4,149,000 disallowance) by using the Company's 2022 Employee Savings Plan expense of \$29.699 million, escalated 2.7% annually based on a five-year (2018-2022) average of the annual growth rate in the expense (Rueckert, 7t 4680).

The Company disagrees for two reasons. First, Staff's reliance on the annual change in the expense is flawed because the annual changes include the impact of increases in the proportion of Employee Savings Plan costs capitalized. Second, Staff's use of 2022 as the starting point is

improper because the Company realized an abnormally high number of forfeitures in 2022 due to employees leaving the Company prior to vesting (Cooper, 5T 1427). Eliminating the excess forfeitures results in adjusted 2022 expense of \$30.077 million (Exhibit A-37, Schedule BB4, line 42, column (h)). Both 2021 and 2022 should also be excluded from the annual escalation because they were impacted by the COVID-19 pandemic, which is a definitive one-time experience that produced a low level of new employees in 2020 (during the pandemic) and a high level of resignations in 2021 (as the economy transitioned out of the pandemic) (Cooper, 5T 1427-29).

In the alternative, Company witness Cooper has refined Staff's proposal by using Exhibit A-37, Schedule BB4, which reflects calculations that adjust Staff's proposed expense. Starting with \$29.699 million (from Exhibit S-9.4) and adjusting it for excess forfeitures in 2022 (\$0.378 million) yields \$30.077 million, which is then escalated by 7.5% (average annual percent change in 2017-2020) resulting in a projected test year expense of \$34.580 million (Cooper, 5T 1429).

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 \$51.269 million in the historic test year, to \$56.961 million in the projected test year. This increase reflects the normalization of the 2021 historical Active Healthcare costs to reflect an historical average of constant dollar costs and thereby establish a sound starting point, which results in a decrease of \$2.566 million (Exhibit A-13, Schedule C5.11.3). The 2021 normalized Active Healthcare costs of \$48.703 million are then escalated for the adjusted medical plan trend of 6.0% in 2022, 5.5% in 2023, and 5.0% in 2024 (Cooper, 5T 1358-59; Exhibit A-13, Schedule C5.11, line 11).

Company witness Cooper further explained that annual unadjusted medical trend factors of 7.5% for 2022, 2023, and 2024 are based on projections for healthcare trends provided by the

healthcare experts at Willis Towers Watson (WTW), as reflected on Exhibit A-13, Schedule C5.11.1.⁸⁸ WTW's trend factors are adjusted by 1.5% in 2022, 2.0% in 2023, and 2.5% in 2024 to reflect the expected savings from the Company's Wellness program, (to 6.0% in 2022, 5.5% in 2023, and 5.0% in 2024), and are corroborated by a study by PricewaterhouseCoopers LLP's (PwC) Health Research Institute (reflected on Exhibit A-13, Schedule C5.11.2), which projects that medical costs will increase by 7.0% in 2021, and 6.5% in 2022 (Cooper, 5T 1368-69). Company witness Cooper 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 25.4% in 2021 and as low as -4.6% in 2020. 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, due to the Company having less than 4,000 employees covered by the Company's self-insured medical plans, it only takes a few extraordinary claims to have a dramatic impact on the Company's Active Healthcare costs in any given year. Simply put, the population of the Company's employees covered by the Company's self-insured medical plans is just too small to infer that the experience over a few years is predictive of the Company's future costs. Accordingly, the adjusted trend factors of 6.0% in 2022, 5.5% in 2023 and 5.0% in 2024 reflected in Company witness Cooper's projected Active Healthcare expense, which are based on national trends, represent a superior source for predicting future increases than the Company's historical annual changes as it is a better predictor of overall trends and costs (Cooper 5T 1350-1362, Exhibit A-13, Schedule C5.11.1, page 4).

⁸⁸WTW first develops an Allowed Trend, which is then adjusted for the Company's actual plan design to develop the future Medical Plan Trend applicable to the Company (Cooper, 5T 1368).

Staff proposed \$59,111,000 (a \$5,442,000 reduction from \$64,553,000 including Life Insurance and Benefit Plan Administration Fees) based on the Company's historical normalized Active Healthcare expense (\$55.3 million) escalated by 2.31% annually (average annual growth rate in expense for 2017-2021). (Rueckert, 7T 4682).

The Company disagrees because Staff's proposal has several flaws, including the use of total Active Healthcare costs including Life Insurance and Benefit Plan Administration fees, which distorts the calculations and produces understated results (Cooper, 5T 1430-31). Exhibit A-37, Schedule BB6 uses an approach similar to Staff Exhibit S-8.6, except it uses total actual healthcare costs, before any portion of those costs are capitalized, which results in a five-year average annual increase of 4.4 % for the combined cost components used by Staff witness Rueckert, which is inclusive of Medical, Dental, Vision, Life Insurance and Benefit Administration Fees, compared to the Staff's five-year average of 2.31% for the same expense categories components. Moreover, since Staff Witness Rueckert disagrees with the constant dollar adjustment, as reflected in Exhibit A-37, Schedule BB5, which is the Staff's response to the Company's discovery question to Staff witness Rueckert, Company witness Cooper's corrected projection of the Company's Active Healthcare expense excludes the constant dollar adjustment. The use of consistent expense components but with the elimination of the constant dollar adjustment and the escalation of these costs by the five-year average annual increase of 4.4% results in a projected Active Healthcare expense of \$65.864 million compared to Staff witness Rueckert's projection of \$59.111 million, as reflected on Exhibit A-37, Schedule BB6, column (e), line 37. While this correction to the Staff's proposal addresses the improper use of the Company's historical increases in its Active Healthcare expense as a basis for determining the Company's projected Active Healthcare expense, which is distorted by the impact of increases in the Company's capital expenditures in the recent past, as

well as the exclusion of the constant dollar adjustment, which Staff witness Rueckert opposes, Company witness Cooper also presented an alternative to the Staff's projected Active Healthcare expense that is based on the three traditional components of Active Healthcare expense, to-wit, Medical, Dental and Vision, to develop a five-year average annual increase of 6.3%. The 6.3% average annual increase is applied to the unadjusted historical test period Active Healthcare expense of \$51.269 million, as per Exhibit A-13, Schedule C5-11, column (b), line 11 to produce projected Active Healthcare expense of \$61.237 million before the inclusion of Life Insurance and Benefit Plan Administration Fees. The addition of the Company's projected Life Insurance and Benefit Plan Administration Fees, which have not been specifically contested by any party, results in projected Active Healthcare expense of \$68.828 million, as reflected on Exhibit A-37, Schedule BB6, column(g), line 37 compared to Staff witness Rueckert's projection on Exhibit S-8-6 of \$59.111 million. While the Company has provided two alternative projections of Active Healthcare expense to that proposed by Staff witness Rueckert, the Company presents these alternatives as corrections to the Staff's proposal and continues to support the Active Healthcare expense initially projected by Company witness Cooper on Exhibit A-13, Schedule C5.11 (Cooper, 5T 1431-33).

AG witness Coppola projected Active Healthcare costs of \$53.705 million (a \$3.256 million reduction) based on the Company's 2022 Active Healthcare costs with annual escalations of 3.33% based on historical increases in the Company's Active Healthcare costs, including Medical, Dental and Vision cost components (Coppola, 6T 3779).

The Company disagrees with Mr. Coppola's use of 2022 to produce a lower starting point, instead of the 2021 historical starting point, and could not replicate his escalation rate (seemingly using 3.30%, which is inconsistent with his testimony and the underlying data) (Cooper, 5T 1434).

⁸⁹ Exhibit A-37, Schedule BB8 recasts Exhibit AG-1.55, except it is based on 2016-2021 to be consistent with the 2021 historical test year. The resulting projection is \$56.564 million, which is comparable to the Company's original \$56.961 million projection (Cooper, 5T 1435).

It is improper to use the Company's actual 2022 Active Healthcare costs as the starting point as these costs are subject to significant variability from year to year. The Company accounted for this variability by using the Company's constant dollar Active Healthcare expense adjustment (Cooper, 5T 1435-36).

Mr. Coppola mischaracterized the Company's constant dollar normalization adjustment as "simply compounding inflationary increases on top of inflationary increases . . . [in a] brazen attempt to inflate forecasted O&M expenses" (6T 3778). To the contrary, the 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 \$2.566 million constant dollar normalization adjustment to the Company's actual 2021 Active Healthcare costs is designed to eliminate this volatility and reduce the risk of selecting an unrepresentative starting point. The volatility of the Company's actual Active Healthcare costs is graphically demonstrated on Table 1 of Company witness Cooper's direct testimony (at 5T 1360) where annual changes range from a 25.4% increase in 2021 to a 4.6% decrease in 2020. Such year-to-year volatility highlights the inherent flaw in solely using historical annual changes in the Company's actual Active Healthcare costs to project future increases (Cooper, 5T 1359-61, 1435-38).

⁸⁹ Exhibit A-37, Schedule BB7 uses the information on Exhibit AG-1.55, but escalates costs by 3.96% rather than 3.30%, resulting in a \$0.663 million increase (Cooper, 5T 1434).

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

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

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

In the event that the Commission disagrees with the constant dollar adjustment (which would be inappropriate), Exhibit A-37, Schedule BB8 projects the Company’s Active Healthcare expense as \$59.544 million based on 2021 actual costs without the constant dollar adjustment (Cooper, 5T 1436-37) based on AG witness Coppola’s use of historical average annual increases in the Company’s Active Healthcare costs.

Similar to the alternative projections of Active Healthcare expense provided in response to the proposal of the Staff, the Company continues to support the total projected Active Healthcare expense reflected on Exhibit A-13, Schedule C5-1, page 2 of 2, column (j), line 14 of \$64.553 million, which is inclusive of all Active Healthcare expense components (i.e., Medical, Dental, Vision, Life Insurance and Benefit Plan Administration Fees) as adjusted for the constant dollar normalization adjustment and escalated based on the adjusted WTW's annual escalations of 6.00%, 5.50% and 5.005 in 2023, 2024 and 2025, respectively.

Therefore, the Commission should approve the Company's requested \$56.961 million Active Healthcare expense.

vi. Other Employee Benefit Costs

The Company's Other Employee Benefits are projected to increase from \$8.82 million in 2021 to \$11.092 million in the projected test year (Exhibit A-13, Schedule C5.11, line 27). 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 (Cooper, 5T 1369-73). No party disputed full recovery of these costs and the Commission should approve them as requested.

11. 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; and (3) differentiate total rewards based on both organizational unit and individual contributions and results. (Cooper, 5T 1375). 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 executive level employees, and Rewarding Employees Plan (REP), available to all other non-represented employees. In addition, the Company provides a multiple-year incentive plan delivered through the Long-Term Incentive Plan (LTIP), which is generally available to managers and above, and up to 10% of other non-represented employees. Company witness Cooper provided a detailed description of the design and mechanics of these plans (Cooper, 5T 1387-95; Exhibit A-21, Schedules K1 through K6 Revised).

DTE Electric seeks to recover the \$62.903 million net projected test period incentive compensation expense, which excludes the expense allocated to the Company for DTE Energy's top five executives. (Cooper, 5T 1383-84). The performance measures included within the plans incorporate both operating and financial metrics. 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 (Cooper, 5T 1396).

	<u>LTIP</u>	<u>AIP</u>	<u>REP</u>	<u>Total</u>
Financial	\$24.8	\$4.7	\$13.9	\$43.4
Operating	<u>\$0.4</u>	<u>\$4.7</u>	<u>\$14.4</u>	<u>\$19.5</u>
Total	<u>\$25.2</u>	<u>\$9.4</u>	<u>\$28.3</u>	<u>\$62.9</u>

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. Employee Engagement measures encompass employee engagement as measured by the Gallup survey and employee safety. Operating Excellence includes measures related to fossil power plant reliability,

reducing the length of service interruptions, as well as additional specific measures related to the nuclear generation business unit (Cooper, 5T 1390-93). Company witness Cooper also explained how the benefits of the operating measures are quantified. (5T 1399-1403).

Staff proposed to exclude \$43,821,000, representing the entire incentive compensation expense related to financial measures, indicating that it understood recent decisions by the Commission to have established a “policy” of excluding financial performance measures from the revenue requirement (McMillan-Sepkoski, 7T 4578-79). To the contrary, the Commission has not made a sweeping policy, but instead based its decisions on the evidence (*e.g.*, Case No. U-18255, 4/17/2018 Order, p 49). The Commission has expressly recognized that “each case must be evaluated on the record in that case.” (Case No. U-18014, 1/31/2017 Order, p 85).⁹⁰ Thus, financial measures have not been, and cannot lawfully be, categorically disallowed as Staff suggests.⁹¹ Staff’s proposed disallowance, along with similar proposals including ABATE’s proposed \$43.399 million disallowance related to financial measures (York, 4T 1118), also ignores the benefits resulting from a financially healthy company and the importance of offering total compensation that is sufficient to attract and retain employees, as further discussed below (Cooper, 5T 1407-1408, 1411-12, 1420).

Staff’s proposed \$43.821 million disallowance includes \$0.422 million of Long-Term Incentive plan (LTIP) expense dependent on Nuclear Generation business unit operating measures. This proposed disallowance is improper even under Staff’s reasoning because these operating

⁹⁰ The Commission also approved Consumers Energy Company’s (Consumers) cost recovery for its employee incentive compensation program (EICP), which was structured with 50% of an employee’s incentive based on achievement of operational and performance measures, and the other 50% based on the achievement of financial measures (Case No. U-17735, 11/19/2015 Order, pp 73-74, 78).

⁹¹ Michigan’s Constitution requires the Commission’s findings to “be supported by competent, material and substantial evidence on the whole record.” Const 1963, art 6, § 28. The APA similarly precludes the Commission from making decisions based on non-record materials. MCL 24.276.

measures (the INPO Index and Nuclear On-Line Capability Factor) are unrelated to financial results, and therefore meet the Commission's traditional practice of requiring quantified customer benefits through improved reliability and lower costs (Cooper, 5T 1408-10).

AG witness Mr. Coppola proposed the complete elimination of incentive compensation expense related to financial measures (\$43.399 million), plus 48% of incentive compensation expense related to operating measures (\$9.362 million), which totals \$52.761 million (6T 3791).

DTE Electric's proposal to include incentive compensation expense related to both the operating and financial measures is fully supported by the record in this case. DTE Electric provided an in-depth cost/benefit analysis demonstrating a \$25.044 million net customer benefit (\$87.947 million total customer benefits minus \$62.903 million total incentive plan costs). (Cooper, 5T 1398, 1403; Exhibit A-21, Schedule K6 Revised). The erroneous presumption that shareholders benefit exclusively from the Company's achievement of its financial measures also ignores the value to customers of avoided interest costs resulting from the Company maintaining its existing credit ratings, which represents a total customer benefit of \$24.0 million (Cooper, 5T 1399, 1415-16; Exhibit A-21, Schedule K6 Revised).

Incentive compensation programs are an increasingly prevalent practice among the vast majority of energy companies.⁹² 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*

⁹² A 2021 study by WorldatWork and Compensation Advisory Partners indicates that the vast majority of companies have both short-term and long-term incentive programs. Moreover, a 2018 study by Aon of U.S. Salary Increases shows that 90% of Power and Gas Service providers utilized broad-based incentive compensation programs (Cooper, 5T 1385-86).

annual compensation of DTE Electric employees is unreasonable or imprudent. Further, the focus on the variable portion of total compensation is also inappropriate because DTE Electric's incentive programs are not additional compensation over and above what other companies pay for similar jobs. Instead, DTE Electric's incentive compensation programs are one of two components that make up DTE Electric's total annual compensation package, which is comparable to other companies competing for the same employees (Cooper, 5T 1375-76, 1384, 1411-12).

This point bears emphasis because failing to approve total incentive compensation expense is inconsistent with the reasonableness of total compensation. DTE Electric's analysis of virtually all incumbent salaries as of December 31, 2021 shows that the Company's total compensation is insignificantly different from market medians (Cooper, 5T 1381-82, 1412; Exhibit A-21, Schedule K1). Moreover, without the Company's short-term incentive compensation programs, the Company's pay would be 11.8% less than the market medians (Cooper, 5T 1382).

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

Customers benefit every day from employees who have the requisite skills and experience to ensure the delivery of quality customer service. DTE Electric's compensation philosophy and

framework benefit all customers by providing a high level of service at competitive costs, with properly compensated employees having an at-risk element of compensation that provides incentives for safe, reliable, and efficient utility service that benefits every customer. (Cooper, 5T 1376, 1384-85).

Staff further proposed the disallowance of \$6,534,000 of Restricted Stock expense, reasoning that it relates to the achievement of financial performance measures. (McMillan-Sepkoski, 7T 4579-80). Company witness Cooper explained that the LTIP has two components (Performance Shares and Restricted Stock). Performance Shares, which represent \$25.234 million of the Company's projected LTIP expense, are granted annually as detailed on Exhibit A-21, Schedule K5. In contrast, Restricted Stock, which represents \$6.534 million of projected LTIP expense, is granted annually to encourage continued employment of certain key executives, and the value is not dependent on the Company's achievement of any financial measures. Therefore, Staff's proposed disallowance is unfounded and should be rejected (Cooper, 5T 1394-95, 1408-1409).

Staff asserted that both Performance Shares and Restricted Stock are "based on DTE Energy Company stock prices, which is a financial measure used by the Company to determine the amount of the award" (McMillan-Sepkoski, 7T 4579). Staff's assertion is incorrect. The stock price is not used to measure the awards; instead, the stock is used as the form of payment to deliver the awards (like dollars, bitcoin or other methods of payment). The number of shares used to pay the LTIP grant is simply adjusted depending on the stock price when the grant is paid. The amount of payment is the same regardless of how it is paid. The method of payment does not somehow change the payment (which remains the same in amount) into a financial measure (Cooper, 5T 1410).

Similarly, with regard to the Nuclear Generation operating measures, the cost is no different than the AIP and REP costs relating to operating measures. The principal distinction is that these

LTIP awards are made in stock rather than cash. This distinction in the method of payment (and not the underlying measure of payment) does not support different treatment (Cooper, 4T 1410-11).

Staff's proposal is also apparently based on an incorrect inference. Staff cited a phrase from the Company's LTIP employee plan description booklet (Exhibit S-9.2), indicating that the LTIP is "a reward to employees for assisting the Company in reaching its financial performance goals" (McMillan-Sepkoski, 7T 4579). Staff's inference is incorrect because the LTIP employee plan descriptive booklet describes the potential benefits to employees of future increases in DTE Energy's stock price. That potential future benefit has no effect on the amount of compensation delivered, and the Company's corresponding costs. Again, the amount is unchanged regardless of whether it is paid in cash or stock. The potential gain on stock is irrelevant, just like the gain that the employee could get on a cash payment by putting it into a savings account or other investment (Cooper, 5T 1410, 1412-14).

AG witness Coppola proposed to exclude 48% of incentive compensation expense relating to operating measures based on his analysis of the operating performance levels achieved for the years 2018 through 2022 (6T 3791; Exhibit AG-1.57). Company witness Cooper explained that Mr. Coppola's analysis is flawed because it failed to recognize that while certain measures may produce results less than Target, other measures can produce results greater than Target. There are also various gradients of performance between Threshold and Maximum. Exhibit A-37, Schedule BB1 shows that for the last five years, the actual weighted performance was 87.1% for the AIP, and 77.6% for the REP (Cooper, 5T 1416-18).

This average annual performance method is more accurate than Mr. Coppola's simplistic binary approach (either the target was met, or not), and it recognizes that actual payouts can fall within a wide spectrum of performance levels. It is not reasonable to assume that only 52% of

operating performance measures will be achieved as the AG suggests. The Company’s goal is to establish costs at levels that are likely to be achieved, so it is reasonable to assume that the Company will, on an overall basis, achieve Target performance levels (Cooper, 5T 1418).

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

The Company recognizes that in its most recent rate case, the Commission adopted the AG’s proposed 40% disallowance of operating measures (Case No. U-20836, 11/18/2022 Order, p 301; Case No. U-20940, 12/9/2021 Order.). The Commission further stated: “In addition, the

⁹³ The Commission long ago recognized that: “Executive bonuses have often been viewed as an appropriate cost of operating a utility.” (Case Nos. U-10149 and U-10150, 10/28/1993 Order, p 57) (rejecting the ALJ’s total exclusion recommendation; adopting Staff’s 50/50 sharing proposal; and advising DTE Gas that “future approval of an incentive bonus plan like this requires a showing that it will not result in excessive costs and that the benefits to the utility’s ratepayers will be commensurate with those costs”). See also, for further example, Case No. U-17767, where the Commission approved DTE Electric’s recovery of costs attributable to operating measures, stating that:

[I]n the immediate case, the Commission finds that DTE Electric provided convincing evidence that the operating (non-financial) measures for the AIP and REP provide appreciable benefits to customers, and meet the standard set forth in the April 28, 2005 order in Case No. U-13898 (April 28 order) and the December 23, 2008 order in Case No. U-15244 (December 23 order)... [Case No. U-17767, 12/11/2015 Order, p 76.]

Commission authorizes DTE Electric to implement a two-way tracker mechanism, which will require refunds to customers if the 60% target level is not achieved or will allow the company to recover additional funds if it exceeds the 60% target level, up to a maximum of 100% target level. DTE Electric shall record the over- or under recovery, compared to the 60% base, in a regulatory asset or regulatory liability to be included in the company's next general rate case." (Case No. U-20836, 11/18/2022 Order, pp 301-302).

The mechanism is unnecessary if the Commission approves the Company's requested recovery. If the Commission approves a lesser amount, however, then the Company would request that the deferral be continued, but with three modifications. First, the base amount should be reset equal to the amount of incentive compensation approved for recovery in base rates in this case. Second, the mechanism should apply to the totality of the Company's incentive compensation program, including the portion related to financial metrics, since the Company's compensation practices are reasonable and prudent, as discussed above. Third, the deferral should cover the total actual payout, including amounts above 100% of the target. The incentive program allows for a range of payouts from zero to 200% of target. The incentive program is designed to motivate employees to achieve results beyond the target, further improving organizational performance and benefitting customers. Since the Company would be mandated to provide a refund to customers if results fell below the baseline, it is reasonable to include the cost of achieving exceptional results (Cooper, 5T 1419-20; Uzenski, 5T 1551).

DAAO witness Koeppel proposed the complete disallowance of incentive compensation expense (6T 3988). This Commission should reject this blanket disallowance for the reasons discussed above, emphasizing that it (1) ignores the qualified customer benefits reflected on Exhibit

A-21, Schedule K6, and (2) disregards the overall reasonableness of the Company's compensation, as reflected on Exhibit A-21, Schedule K1. (Cooper, 5T 1420-21).

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 based on comparison to the Company's peers, and that there is no valid reason to disallow the Company's requested cost recovery. Therefore, based on the evidence in this record the Commission should approve DTE Electric's request to include all the Company's incentive compensation expense (except for the top five DTE Energy executives) in the revenue requirement adopted in this case.

D. Depreciation and Amortization, and AFUDC

DTE Electric seeks to recover \$1,168.9 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 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, 5T 1509).

The projected \$178.9 million D&A increase was due primarily to \$228.8 million for capital in-service movement. Software amortization also increases by \$416.2 million in the projected period. These increases are partially offset by approximately \$66.7 million for plant retirements (Uzenski, 5T 1509).

As discussed in Section I, the Company has now made a \$293.7 million reduction to its capital projections. This reduction correspondingly reduces the Company's projected D&A expense

by \$6.5 million. These adjustments result in a revised projected D&A amount of \$1,162.5 million, which should be approved by the Commission.

Staff's Exhibit S-3, Schedule C1, line 5, column (d) reflects a \$23.0 million decrease to depreciation based on Staff's proposed disallowances. Apart from whether projects should be approved, the Company generally agrees with Staff's method for calculating the depreciation impact, but notes that a few of the proposed disallowances relate to projects that the Company assumed to be under construction so they were not reflected in Plant in Service (listed in Exhibit A-36, Schedule AA2). Instead, these projects were reflected in Construction Work in Progress (CWIP), which is not included in the Company's projection for depreciation expense. Therefore, to the extent that the Commission accepts Staff's proposed disallowances for items listed in Exhibit A-36, Schedule AA2, there should not be any reduction to depreciation expense (Uzenski, 5T 1564, 1571-72).

Similarly, several parties have proposed disallowances of projects that are not in service in the projected test period, but none of the parties proposed an adjustment to Allowance for Funds Used During Construction (AFUDC). If the Commission decides to reduce projected rate base by these projects, then it should also reduce pre-tax AFUDC within net operating income (Uzenski, 5T 1565, 1572-73).

E. Property and Other Taxes

DTE Electric seeks to recover \$320.3 million of property tax expense for the December 2023 through November 2024 projected test period (Wisniewski, 5T 2573; Exhibit A-13, Schedule

C1, column (e), line 6). This amount is calculated by taking 1/12th of the 2023 calendar year expense, plus 11/12ths of the 2024 calendar year expense (5T 2574).⁹⁴

DTE Electric projects a \$50.2 million Other Tax Expense for the projected test year, consisting of payroll taxes (\$37.9 million), Public Utility Assessment fees (\$12.2 million), and miscellaneous other taxes (\$0.1 million) as shown on Exhibit A-13, Schedule C7, column (j), lines 2-5 (Wisniewski, 5T 2574). No party disputed full recovery of these costs.

F. Income Tax Expenses

DTE Electric seeks a total income tax recovery of \$111.3 million (Wisniewski, 5T 2574). DTE Electric projects a \$46.8 million federal income tax (FIT) expense for the projected test year, based on a 21% FIT rate (Wisniewski, 5T 2565, 2574-75; Exhibit A-13, Schedule C8, line 52). DTE Electric projects a \$62.4 million Michigan Corporate Income Tax (MCIT) expense, based on a 5.88% rate (5T 2565, 2576; Exhibit A-13, Schedule C9, line 14). DTE Electric projects a \$2.1 million municipal income tax expense, based on a 0.33% composite municipal income tax rate (Wisniewski, 5T 2565, 2576; Exhibit A-13, Schedule C10, line 11).

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 May 8, 2020 Order in Case No. U-20561, and November 18, 2022 Order in Case No. U-20836. Amortization for the December 2023 through November 2024 test period reduces tax expense by \$51.9 million

⁹⁴ The projected 2023 property tax liability is \$309.2 million (Wisniewski, 5T 2571; Exhibit A-13, Schedule C7.1, column (c), line 54). The projected 2024 property tax liability is \$344.2 million (Wisniewski, 5T 2572; 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, 5T 2565-66, 2570, 2573).

(Wisniewski, 5T 2575; Exhibit A-13, Schedule C8, line 48). No party disputed full recovery of these costs.

VIII. OTHER REVENUE RELATED ISSUES

A. Infrastructure Recovery Mechanism (IRM)

The Company proposes a Distribution IRM to facilitate the distribution system upgrades that must be made to maintain and improve safety and reliability. The IRM is supported by prior guidance from the Commission. In Case No. U-20162, the Company proposed an IRM to recover the incremental revenue requirement associated with certain distribution, fossil generation and nuclear generation capital expenditures. The Commission did not adopt that proposal, but stated:

The Commission is receptive to considering an IRM with the proper oversight, legal structure, and performance-based regulation framework including customer protections. [Case No. U-20162 Order dated May 2, 2019, p. 117.]

The Company did not propose an IRM in its last rate case, but the Commission indicated that it might consider one in the context of discussing strategic capital investments in the Company's distribution system:

The Commission cannot stress enough its expectation that DTE Electric will invest the amounts approved for strategic capital investments and not shift them to other categories such as emergent replacement and other reactive spending. As such, *the Commission may be willing to consider a long-term investment recovery mechanism* (similar to the Infrastructure Recovery Mechanism for the gas Main Renewal Program first approved in the April 16, 2013 order in Case No. U-16999) to ensure that the spending included in rates for strategic capital improvements—including the ultimate conversion of DTE Electric's distribution grid—is spent for these purposes, and to provide greater long-term certainty on recovery of reasonable and prudent costs related to these strategic distribution grid investments. The Commission expects that DTE Electric will include in any such proposal a full description of costs and benefits, as well as associated timelines. [Case No. U-20836 Order dated November 18, 2022, p. 77. Emphasis added.]

Accordingly, the Company now proposes a Distribution IRM focused on strategic capital programs. Based on the Commission's guidance, the Company broadly looked for programs critical

to customer safety, reliability, and/or resilience, and specifically identified programs supporting the ultimate conversion of the Company's distribution grid. (Foley, 2T 50, 54, 62). The Company proposes to include five programs in the initial Distribution IRM:

1. Circuit Conversions, including both City of Detroit Infrastructure (CODI) and non-CODI conversions (Foley, 2T 63-64; Deol, 2T 190-92; Exhibit A-23, Schedule M5);
2. Sub-transmission Redesign & Rebuild (Foley, 2T 63-64; Deol, 2T 190-93; Exhibit A-23, Schedule M5);
3. Breaker Replacement (Foley, 2T 64-64; Elliott Andahazy, 3T 500-504; Exhibit A-23, Schedule M4);
4. Underground Residential Distribution (URD) Replacement (Foley, 2T 63-64; Elliott Andahazy, 3T 500-504; Exhibit A-23, Schedule M4); and
5. 4.8 kV Circuit Automation (Foley, 2T 63-64; Hill, 5T 2732-34).

The proposed Distribution IRM is also largely based on the DTE Gas IRM that the Commission referenced in Case No. U-20836 (Foley, 2T 59). The DTE Gas IRM began when the Commission approved DTE Gas's recovery of 2013-17 IRM capital investments for the Meter Move Out Program (MMO),⁹⁵ the Main Renewal Program (MRP),⁹⁶ and incremental MRP and Pipeline Integrity (PI) investments (April 16, 2016 Order in Case No. U-16999). The Court of Appeals affirmed this decision. *In re Application of Michigan Consolidated Gas Company to increase rates*, unpublished opinion per curiam of the Court of Appeals, issued December 11, 2014 (Docket Nos. 316141 and 316263) (2014 WL 7003882).⁹⁷ The Commission approved additional

⁹⁵ The Commission approved the MMO in its September 13, 2011 Opinion and Order and November 10, 2011 Order Granting Clarification in Case No. U-16451.

⁹⁶ The Commission approved the MRP in its September 13, 2011 Order in Case No. U-16407.

⁹⁷ The Commission has approved various cost recovery trackers, and the Court of Appeals has consistently affirmed them. In addition to DTE Gas's IRM, see, for example, *In re Applications of Detroit Edison Company*, 296 Mich App 101, 114; 817 NW2d 630 (2012), where the Court of Appeals affirmed four cost trackers for DTE Electric in Case No. U-15768 (an Uncollectible Expense Tracking Mechanism (UETM), a storm and non-storm restoration normalization tracker, line clearance expenses tracker, and Choice Incentive Mechanism (CIM)). The Court explained in part that

infrastructure investments as part of an expanded IRM for 2016 and 2017 (November 23, 2015 Opinion and Order in Case No. U-17701), and authorized additional spending of \$102.1 million in 2016, and \$127.6 million in 2017 through 2021 on IRM programs, as well as flexibility in spending among the programs (December 9, 2016 Order in Case No. U-17999, pp 52, 67). In DTE Gas's next rate case, the Commission approved additional capital expenditures, including funding to further expand and accelerate infrastructure replacement (September 13, 2018 Order in Case No. U-18999, pp 21, 26, 32-33). Most recently, the Commission again approved additional funding for the DTE Gas IRM and rejected anti-IRM arguments (December 9, 2021 Order in Case No. U-20940, p 172).

The proposed IRM would provide four key benefits. First, the Distribution IRM would provide certainty of investment in key distribution capital programs focused on customer safety, customer reliability, and the integration of increasing levels of Electric Vehicles (EVs) and other Distributed Energy Resources (DERs). It also directly responds to the Commission's expectation that "DTE Electric will invest the amounts approved for strategic capital improvements and not shift them to other categories" (Case No. U-20836 Order dated November 18, 2022, pp. 76-77, further quoted above). Under the proposal, the Commission would approve both the amount of the investment and the specific programs. The Company would not be able to recover its capital costs between rate cases for programs not covered by the IRM, or if the Company shifts investment amounts among programs. Any underinvestment in the programs associated with the IRM would be returned to customers, providing the appropriate customer protections requested by the Commission (Foley, 2T 55-56, 61-62).

"our caselaw confirms that the PSC correctly approved Detroit Edison's use of cost tracking mechanisms through which future rates are adjusted to take account of actual past expenses."

Second, the Distribution IRM would provide greater transparency into both the Company's investment plans and its execution of those plans. The Company proposes an annual "IRM Planning Process" that would provide Staff with greater detail about the Company's investment plans for the upcoming year. The Company also proposes an annual "IRM Reconciliation Process" that would provide information about the Company's execution of its investment plan, including projects completed compared to what was planned, and actual project costs compared to what was planned (Foley, 2T 55-57). Both processes are modeled after the DTE Gas IRM processes (Foley, 2T 59). The Planning Process would (1) provide greater transparency related to the Company's plans for its IRM investments, and (2) solicit feedback from Staff regarding the Company's plans (Foley, 2T 73-76). The Reconciliation Process would (1) provide greater transparency into the Company's execution of its IRM investment plans, and (2) reconcile actual investment and plant-in-service to planned investment and plant-in-service so that any over-recovery associated with program under-investment can be returned to customers (Foley, 2T 76-77).

Third, the Distribution IRM would provide Staff with additional opportunities to review and provide input on the Company's investment plans as part of the proposed IRM Planning Process (Foley, 2T 55, 57).

Fourth, the Distribution IRM would result in increased accountability for the Company to fully execute its strategic investments. As part of the IRM Reconciliation Process, the Company proposes to begin reporting new program execution metrics that are designed to specifically address the Company's execution of its investment plans (Foley, 2T 54, 57). The execution metrics are modeled after the DTE Gas IRM, which has metrics for both work completed and project costs. The Company proposes to report specific execution metrics for the Conversions program (Foley, 2T 78; Deol, 2T 194); Sub-transmission Redesign & Rebuild program (Foley, 2T 79; Deol, 2T

194); Breaker Replacement program (Foley, 2T 79; Elliott Andahazy, 3T 504); URD Replacement program (Foley, 2T 79-80; Elliott Andahazy, 3T 504); and 4.8 kV Circuit Automation program (Foley, 2T 80; 5T 2735).

In addition to these immediate benefits, another longer-term objective is to extend the time between rate cases, reducing administrative burdens and costs (Foley, 2T 57-58).

The Company proposes to establish a roughly three-year IRM that begins concurrent with the projected test year in this case (on December 1, 2023). Typical distribution planning and reporting activities are completed on a calendar year basis, so the Company proposes 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 (Foley, 2T 61).

The level of investment for each program in each IRM Plan Year is outlined in Exhibit A-33, Schedule X1, and summarized in Table 1 at Foley, 2T 66. There are different funding levels for different programs in the initial years due to the nature of the projects involved. By IRM Plan Year 3, the Company proposes that the full proposed investment in the programs be authorized for IRM treatment (Foley, 2T 64-65, 68).

IRM surcharges are calculated similarly to the calculation of base rates (Foley, 2T 69-70). Company witness Vangilder calculated the IRM revenue requirement (Vangilder, 5T 2596-98; Exhibit A-33, Schedule X4). Company witness Maroun allocated the IRM revenue requirement to the various voltage classes (Maroun, 5T 3153; Exhibit A-33, Schedule X6). Company witness Willis calculated IRM surcharges consistent with overall distribution rate design (Willis, 5T 3212-15; Exhibit A-33, Schedule X7).

AG/MNSC witness Alvarez suggested that the IRM should be rejected because it would reduce regulatory lag, which he characterized as a "brake on utility spending" (6T 3340-41). The

Company disagrees because it is appropriately proposing IRM treatment for certain investments, as discussed above. If the Commission approves the IRM, then it would be deeming those investments reasonable and prudent, and the Company should be able to fully recover the costs of those investments. Reducing or eliminating regulatory lag is entirely appropriate and will facilitate the timely implementation of capital expenditures that benefit the Company's customers. Mr. Alvarez also disregarded that the IRM is an effective cost-control measure, since both the timing and level of capital investments would be established in the instant case. (Foley, 2T 86-87, 132-33).

AG/MNSC witness Stephens suggested that, if approved, the IRM should be "reserved for emergency situations not considered during the development of a five-year distribution plan" (6T 3407). The Company disagrees because this is contrary to the Commission's guidance (quoted above) and the IRM, which follows that guidance (Foley, 2T 87-88).

Kroger witness Bieber (6T 4290) and ABATE witness York (4T 1114) recommended rejecting the IRM based on their assertions that it would constitute single-issue ratemaking. The Company disagrees because its proposed IRM is largely based on the DTE Gas IRM, which has been upheld on appeal and successfully implemented in a number of successive cases, as indicated above (Foley, 2T 89).

Kroger witness Bieber further asserted a set of criteria to consider regarding a cost tracker, and argued that the IRM should be rejected because it does not meet two of the criteria (6T 4293-94). The Company disagrees with Kroger because Mr. Bieber did not support his suggestion that the criteria are either "generally accepted" or an appropriate way to judge the IRM. Mr. Bieber also ignored that DTE Gas's IRM has been in use for several years, and the Commission suggested that it could be used as a model for the Company's proposed IRM in the Commission's November 18,

2022 Order in Case No. U-20836, p. 76 (quoted above). Thus, there is no basis for Mr. Bieber's suggestion that the Commission should change the way it judges IRMs (Foley, 2T 91-92).

CEO witness Kenworthy suggested that the Company should further consult stakeholders and communities beyond Staff on IRM investment plans (6T 3865, 3867). The Company disagrees because stakeholders and communities will have adequate opportunities to provide input and feedback on IRM investments if the IRM were to be approved as proposed. The key parameters of the IRM (specific capital programs, authorized spending, timing, and cost allocation, recovery, and return of any over-recovery) are set during a general rate case (like this case, where there is an opportunity to assess and debate the merits of the Company's proposal). There would also be opportunities to provide input and feedback on past IRM investments, including the ability to challenge those investments for prudence and consistency with the IRM, in subsequent rate cases when the Company proposes to transfer its IRM investments into its rate base (Foley, 73, 93-94, 133-39, 143, 167).

Kroger witness Bieber suggested that the Company should wait to propose an IRM until after it receives guidance from the Commission on Performance-Based Ratemaking (PBR) frameworks (6T 4294). The Company disagrees because the Commission's IRM guidance (quoted above) did not indicate that the Company should wait. The Commission also recently indicated that it would launch a Financial Incentives and Disincentives workgroup (Case No. U-21400 Order dated April 24, 2023). The Company sees no reason to wait while the workgroup proceeds. Delaying the IRM would also delay the IRM's benefits, as discussed above (Foley, 2T 94-95, 161, 172).

ABATE witness York asserted that "the Company's proposed method of calculating the IRM incremental revenue requirement ignores offsetting reductions in the value of plant investment

included in rate base” (4T 1114) and suggested that if the Commission approves the IRM, then “[a] pro rata amount of depreciation expense included in base rates associated with the same type of infrastructure that is proposed to be eligible for the IRM should be used to offset the IRM-eligible investment prior to the rate of return calculation for the IRM surcharge” (4T 1144-35).

ABATE’s proposal is inappropriate and unnecessary because the IRM incremental revenue requirement already fully accounts for net plant, return, depreciation, and property taxes directly associated with the IRM investments. The projected test period revenue requirement has also already been adjusted to account for the removal of the capital expenditures included in the proposed IRM. Moreover, the proposed incremental revenue requirement uses the same methodology as the DTE Gas IRM, which the Commission has repeatedly approved (Vangilder, 5T 2605).

The same response largely applies to witness York’s further assertion that the “proposed IRM surcharge does not appear as though it would reflect the decline in rate base that has occurred since base rates were last set. Thus, in the years between rate cases, customers would be charged both depreciation expense for plant already depreciated and new depreciation expense for new investments through the incremental IRM charge” (York, 4T 1145). In addition to the IRM revenue requirement already properly accounting for depreciation expense and accumulated depreciation for IRM investments, as indicated above, all capital invested through the IRM mechanism would be rolled into the Company’s overall rate base in the Company’s next rate case, as discussed below. Thus, the actual accumulated depreciation associated with the IRM investments would be treated appropriately, and consistently with how all other Company investments are treated (Vangilder, 5T 2606).

As indicated above, the amount of capital that could be recovered for any program through the IRM would not be allowed to exceed the program-specific maximum authorized by the Commission for IRM treatment as proposed in Exhibit A-33, Schedule X1 (Foley, 2T 68, 70). If the Company were to invest more in a program than the level authorized for that program in the IRM, then the Company could seek to recover the additional investment through base rates in a future rate case. If the Company were to invest less in a program than the level authorized for that program, then the over-recovery associated with that under-investment would be deferred as a regulatory liability until a subsequent rate case. At that point, any IRM over-recovery would be returned to customers through a time-bound credit, with short-term interest. The credit would be allocated to the Company's various classes of customers, and calculated in the same manner as the IRM surcharges (Foley, 2T 68, 71-72; Uzenski, 5T 15615T 1503). Mr. Vangilder also prepared an illustrative example (5T 2599-2600; Exhibit A-33, Schedule X5).

The Company proposes that the IRM surcharges would expire when new base rates are implemented after an order in the Company's next general rate case. During that rate case, the Company would propose that all capital invested through the IRM be rolled into the Company's rate base with recovery continuing through base rates. Absent a general rate case, the IRM surcharges would continue indefinitely at the rates established for IRM Plan Year 3, but customers would continue to be protected through the IRM Reconciliation Process (Foley, 2T 72-73).

In summary, the Company's proposed Distribution IRM is well designed and fully supported. Therefore, it should be approved along with the Company's proposed IRM surcharges included in Exhibit A-33, Schedule X7.⁹⁸

⁹⁸ If the proposed IRM is not approved, then the Company requests that the capital expenditures included in the IRM through the projected test year be added back to the forecasted financial statements for recovery in base rates, as discussed by Ms. Uzenski (5T 1560-61). The adjusted revenue deficiency would be \$586 million, which is a \$3.4 million increase to the revised revenue deficiency reflected in Attachments A and B).

B. Pilot Programs

1. 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]he 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. [Case No. U-20162 Order dated May 2, 2019, 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. [Case No. U-20561 Order dated May 8, 2020, 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. [Case No. U-20935 Order dated March 19, 2021, 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 (Case No. U-20836 Order dated November 18, 2022, pp. 320-51).

Against this backdrop, Company witness Peterson provided an update on the actual and estimated expenditures for existing Charging Forward pilots (Peterson, 4T 697-707; Exhibit A-12, Schedule B5.9, p 1). 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 3rd Annual Status Report that the Company filed in June 2022 in Case No. U-20162).

Total program costs for the original Charging Forward pilot were \$3.0 million in 2021, and are projected to be \$8.5 million for the 23 months ending November 30, 2023. There are no costs for the projected test year because by then all activities will have shifted to the Charging Forward Expansion (Peterson, 4T 700; Exhibit A-12, Schedule B5.9, page 2, line 13, columns (b) and (e)).

Total eFleets projected costs were \$0.3 million in 2021, and are projected to be \$5.2 million in the 23 months ending November 30, 2023, and \$4.5 million for the projected test year (Peterson, 4T 705; Exhibit A-12, Schedule B5.9, page 3, line 10, columns (b), (e) and (f)).

Total Charging Forward Expansion costs are projected to be \$18.6 million in the 23 months ending November 30, 2023 (consistent with the approval of the Expansion in Case No. U-20836), and \$33.2 million in the projected test year, as further discussed below (Peterson, 4T 755; Exhibit A-12, Schedule B5.9, p 4, line 24, columns (e) and (f)).

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. [Case No. U-20836 Order dated November 18, 2022, p. 351.]

DTE Electric is beginning to transition to permanent programs in three ways:

1. Recommend tariff changes as appropriate;
2. Propose five elements as permanent, beginning with the projected test period; and
3. Publish a detailed Transportation Electrification Plan (TEP) in Q4 2023, detailing the Company's investment plan through 2028, including detailed program design, investment levels, and benefit-cost analyses (Peterson, 4T 710, 713).

Elements that the Company proposes as permanent meet at least one of the following two criteria: (1) they are participant funded, and therefore are rate neutral over time; or (2) there is a clear need for the element in both the short-term and long-term. The Company proposes to extend the elements that are still being refined in the long-term TEP in pilot form because the role of the utility, targeted customer segments, and element structure are still being refined to support the transition from pilot to permanent program. The Company needs more time to develop a comprehensive TEP because the scope and scale of the long-term investment requires robust analysis, in-depth benchmarking, and careful evaluation of the utility's role to ensure that DTE is providing the right amount of support to Michigan's transportation electrification goals, while ensuring that capital is productively and prudently deployed consistent with customer interests (Peterson, 4T 710-12).

The proposed elements in each category are:

Permanent: Education & Outreach (E&O); Home Charger Installation (previously “Residential Charging as a Service” or “Residential CaaS”) (noted here for completeness, but the Company now proposes to end)⁹⁹; eFleet Battery Support (previously “Transit Batteries” or “eBus Batteries”); Emerging Technology Fund; and Program Administration.

Extended: Home Charger Rebates; Business Charger Rebates; Income-Eligible Rebates; Business Charger Installation (previously “Commercial Charging as a Service” or “Commercial CaaS”); and Charging Hubs.

New: Community Chargers and School Bus Chargers (Peterson, 4T 709, 711).

i. Permanent Program Proposals

The Company’s permanent program proposals include the following rate book modifications:

1. Introduce Rider 22 to create a platform for the Company to install and finance equipment at the customer’s location for the purpose of facilitating EV charging programs (*noted here for completeness but the Company recommends withdrawal, as indicated above and further discussed below*);
2. Modify Rider 21 to include other, larger vehicles for eFleet Battery Support;
3. Clarify language in C5.1 to allow customers to request an additional service for Electric Vehicle Supply Equipment (EVSE);
4. Allow customers to select Rate Schedule D3 in conjunction with D4 (when used to serve EVSE); and
5. Expand Rider 14 to qualify EVs for outflow compensation and encourage vehicle-to-grid (V2G) deployment (Peterson, 4T 713-15; Willis, 5T 3205-3207; Exhibit A-16, Schedule F8).¹⁰⁰

The Company provided a detailed discussion of each of its proposed permanent elements.

Ms. Peterson first discussed the E&O element’s efforts and achievements (See also, generally, Case

⁹⁹ The Company proposes to end Home Chargers Installation by the end of 2023, at which time the Company will transition the offering to a VAPS program. Accordingly, the Company also recommends withdrawal of its proposed Rider No. 22. The cost reductions from withdrawing Rider 22 in the projected test year are \$4.2 million in capital (Peterson, 4T 801).

¹⁰⁰ The Company’s proposed expansion of Rider 14 availability goes beyond electric vehicles, and is further discussed below in section XI. J concerning cost allocation and rate design.

No. U-20836 Order dated November 18, 2022, pp. 320-21). The Company should provide E&O permanently because there is a clear need for it in both the short-term and the long-term. The Company requests \$1.5 million for the projected test period (and annually, going forward), and O&M treatment, which is appropriate for a permanent offering (Peterson, 4T 715-20; Exhibit A-12, Schedule B5.9, page 4, line 11, column (f)).

Home Charger Installation is a turnkey installation and financing solution for customers interested in a Level 2 charger for their single-family homes (See Case No. U-20836 Order dated November 18, 2022, pp. 224-26 discussing Residential Charging as a Service). The Company's original filing proposed that it be permanent, but the Company now proposes to end it by the end of 2023, as indicated above. Projected costs for labor and materials required for the installations are \$2.3 million in the 23 months ending November 30, 2023 (approximately 1,150 home chargers), and the Company withdraws its request for \$4.2 million in the projected test year (approximately 2,100 home chargers). The Company also withdraws its proposed Rider 22. The Company requests capital treatment consistent with the Commission's decision in Case No. U-20836 (Peterson, 4T 720-25; Exhibit A-12, Schedule B5.9, page 4, line 2, columns (e) and (f)).

The eFleet Battery Support element concerns DTE Electric offering to purchase bus batteries on behalf of transit agencies and the costs will be recovered over time on their monthly bills through Rider 21 (See Case No. U-20836 Order dated November 18, 2022, pp. 339-41 discussing Transit batteries/Electric Bus Batteries). The Commission also "encourage[d] DTE Electric to submit, in its next rate case, a proposal for the expansion of the transit battery/eBus batteries pilot that provides an opportunity for school districts to utilize this program to expand electrified school bus fleets" (*Id.* at 340-41). The Company has done so, but in addition, the Company's C&I customers – and Michigan overall – may benefit from including other, similar vehicle segments in this participant-funded program in order to evaluate the impacts. Therefore, the Company proposed to expand eFleet Battery Support and modify Rider 21 to include any vehicle

registered to a business customer of the Company as long as the vehicle battery is greater than 150 kilowatt-hours (kWh), which would include vehicles such as refuse trucks and last-mile delivery vans (Peterson, 4T 725-27).

Accordingly, the Company proposes costs (which will be recouped over time pursuant to Rider 21) of \$2.0 million in the 23 months ending November 30, 2023, and \$3.0 million in the projected test year. The projected increased expenditures could support the deployment of approximately five electric transit buses in the bridge period, and 9-16 fleet vehicles in the projected test year, depending on the battery sizes and vehicles. The Company requests capital treatment consistent with the Commission's decision in Case No. U-20836 (Peterson, 4T 728; Exhibit A-12, Schedule B5.9, page 4, line 3, columns (e) and (f)).

The Emerging Technology Fund allows the Company to efficiently test new technologies and prepare for widespread EV adoption in the future. The Company will also include a Staff member on the Advisory Committee, host regular meetings with the Advisory Committee, and document the element's results, including costs and benefits (Case No. U-20836 Order dated November 18, 2022, p. 346). The Emerging Technology Fund should be permanent because the EV market is going to continue to rapidly evolve for the foreseeable future so there is a need for the Fund in both the short-term and long-term to keep pace with advancements, including battery chemistries, charger solutions, and software applications. Implementation costs are \$0.9 million in the 23 months ending November 30, 2022 (regulatory asset), and \$1.0 million in the projected test year (and annually, going forward, as O&M). The Company received regulatory asset accounting approval in Case No. U-20836, but now seeks O&M treatment as appropriate for a permanent offering (Peterson, 4T 728-30; Exhibit A-12, Schedule B5.9, p4 lines 12 and 22, columns (e) and (f)).

For Program Administration, the Company proposes an EV team of approximately 14 full time equivalent (FTE) employees, consistent with the approved request in Case No. U-20836 for

the Charging Forward Expansion. The EV team should be permanent to provide continuous, stable and high-quality program administration and execution, which will support the Company's role and the State's goals for transportation electrification and decarbonization. The Company requests \$1.8 million for the projected test year (and annually, going forward) as O&M, which is appropriate accounting treatment for a permanent program (Peterson, 4T 730-31; Exhibit A-12, Schedule B5.9, p 4, line 14, column (f)).

ii. Extended Pilot Proposals

These pilot elements should be extended because they are important and appropriate in the near-term to support the Company's EV guiding principles. They are not yet being proposed as permanent, however, because they are still being refined as indicated above. The Company requests funding of \$10.1 million in the 23 months ending November 30, 2023, and \$15.8 million in the projected test year (Peterson, 4T 731-33; Exhibit A-12, Schedule B5.9, page 4). Further details regarding the current status and primary goals of each element are at Peterson, 4T 733-34 (Home Charger Rebates), 4T 734-35 (Business Charger Rebates), 4T 736-37 (Income-Eligible Rebates), 4T 737-38 (Business Charger Installation, previously Commercial CaaS), and 4T 738-39 (Charging Hubs).

Ms. Peterson explained that Charging Hubs will allow the Company to directly pursue available federal and state grants, so it should be extended in the near-term to maximize awards to the Southeast Michigan region that DTE Electric serves, and to further the MI Healthy Climate Plan. To ensure prudence, the Company will add receiving government subsidies as an additional buildout criterion. Also, the Company does not want to compete with third-party developers in the long-term, so the Company proposes Charging Hubs for an extended pilot only, and not as a permanent program (Peterson, 4T 740-41).

iii. New Pilot Proposals

The Company proposes two new pilot elements: Community Chargers and School Bus Chargers (Peterson, 4T 741; Exhibit A-12, Schedule B5.9.1 summarizes how they meet the requirements of the February 4, 2021 Order in Case No. U-20645).

Under Community Chargers, DTE Electric would build, own, operate, and maintain approximately 250-360 Level 2 chargers in public parking locations, including curbside installations such as utility pole-mounted and streetlight-mounted chargers. This element is needed for three primary reasons: (1) there are not enough Level 2 chargers in DTE Electric's service territory; (2) there is a discrepancy in charging access depending on where DTE Electric customers live; and (3) many multi-unit dwelling (MUD) residents are unable to capitalize on the \$1 eGallon equivalent of charging off-peak on a TOD rate. The Company intends to utilize the existing D1.9 tariff structure to assess a TOD-based usage fee to drivers, which would be collected through the charger. The Company seeks key learnings including the utilization, performance, and cost-effectiveness of pole-mounted chargers. Costs are projected to be \$3.6 million for the projected test year. The Company requests capital treatment, consistent with other Company-owned chargers approved in Case No. U-20836 (Peterson, 4T 742-49; Exhibit A-12, Schedule B5.9, page 4, line 7, column (f)).

Under School Bus Chargers, DTE Electric would install, own, operate, and maintain chargers with V2G capability for electric school buses. This element is needed for three primary reasons: (1) school districts are under unique economic and logistical challenges to electrify their fleet with limited resources; (2) school buses have the potential to provide grid benefits due to their operation cadence, but there is little incentive to upgrade to V2G-capable chargers today; and (3) dedicated funding for V2G-capable school bus chargers will preserve funding for other customer segments in DTE Electric's eFleets program. The revenue collected from charging will depend on the customer's electric rate, with no additional fee for usage. Applicants will be required to add

Rider 14 to receive compensation for V2G outflows. The Company seeks key learnings including: (1) impacts on rate of school electrification; (2) applicant and school experience with school bus charging, electric school buses, and V2G; (3) utilization, performance, and costs of chargers; and (4) V2G deployment use cases and characteristics. Costs are projected to be \$2.0 million for the projected test year, which could support the deployment of approximately 16-20 V2G-capable chargers. The Company requests capital treatment, consistent with other Company-owned chargers approved in Case No. U-20836 (Peterson, 4T 749-58; Exhibit A-12, Schedule B5.9, page 4, line 8, column (f)).¹⁰¹

iv. Updated Benefit-Cost Analysis

Total Charging Forward Expansion costs are projected to be \$18.6 million in the 23 months ending November 30, 2023 (consistent with the approval of the Expansion in Case No. U-20836), and \$33.2 million in the projected test year, as further discussed below (Peterson, 4T 755; Exhibit A-12, Schedule B5.9, p 4, line 24, columns (e) and (f)). Based on projected EV sales, and EVs putting downward pressure on overall rates, the Company estimates net present value (NPV) system benefits of \$51.3 million to \$59.9 million for the projected test period (Peterson, 4T 758). Reducing this amount for EV sales not influenced by DTE Electric, and participant-funded elements, the overall NPV net benefits to DTE Electric customers for the projected test period are estimated to be \$2.1 million to \$6.4 million. The Company plans a broader BCA framework for future programs as part of the TEP, as indicated above (Peterson, 4T 760).

There appears to be general support for the Company's proposals, except for the AG, and some witnesses also suggested some modifications to what the Company proposed. The Company

¹⁰¹ The Company also requests ongoing O&M funding for the costs of maintaining Company-owned chargers (Peterson, 4T 755; Exhibit A-12, Schedule B5.9, page 4, line 13, columns (e) and (f)).

responds by topic below, with additional details in Ms. Peterson's rebuttal testimony (4T 793-811).

AG witness Coppola presented calculations suggesting that the program's costs are too high for its benefits (6T 3718-24), and on that basis suggested nine modifications (6T 3725-26). Ms. Peterson explained why the calculations are inaccurate, and that the suggested modifications should be rejected because they are all based on the inaccurate assumption that the net gross margin from EV electricity sales does not benefit the broader customer base (4T 793-95).

The Company also disagrees with Staff (Freeman, 7T 4432) criticisms of its proposed Community Chargers program. This element is needed, as discussed above, and although opinions on Company ownership of charging infrastructure vary, the Company is not aware of any substantial effort to provide the type of community charging service the Company proposes (Peterson, 4T 743-47, 796-97). MEIBC/IEI/United witness Sherman made five recommendations regarding Community Chargers. The Company does not take issue with recommendation 5 (i.e., all charging stations are required to have a NRTL certification and be networked), but otherwise disagrees because the proposed modifications would substantially alter the Company's proposal and are otherwise inappropriate, as further discussed on the record (Peterson, 4T 797-98).

The Company will make an effort to accommodate MNSC witness Jester (6T 3475) and MEIBC/IEI/United witness Sherman's (6T 4186) recommendations regarding School Bus Chargers, so long as the partners (third parties and/or school districts) agree to the Company's vehicle-to-grid scope of work (e.g., controls, communications, interconnection, and maintenance requirements) for the pilot (Peterson, 4T 799). Any such accommodation may require further assurances of Company cost recovery.

MEIBC/IEI/United witness Sherman asserted that eFleet Battery Support "provide[s] services to customers that could be provided by non-utility service providers and, as such, to the

extent they are allowed, should be considered value-added programs subject to the Code of Conduct adopted by the Commission in Case No. U-18361” (6T 4151). The Company disagrees because the intent and structure of eFleet Battery Support is to provide a tariffed program under Rider 21 that ensures the program is participant-funded and overall neutral to rates, while helping to increase the adoption of large EVs. Other approaches would likely not provide the same overall benefits. CEO witness Parra Cobaleda proposed two modifications (create additional incentives for bidirectional chargers, and create a demand response program and leverage revenues generated with bidirectional chargers and bidirectional school busses (6T 3950-51). The Company disagrees with the proposed modifications as inconsistent with Rider 21 and unnecessary (Peterson, 4T 880).

Staff (Freeman, 7T 4431) MEIBC/IEI/United witness Sherman (6T 4163) and EVgo witness Stegall (4T 1003-67) voiced concerns about additional Charging Hubs. The Company understands these concerns, and acknowledges that the deployment of the two approved Charging Hubs is delayed due to the Company seeking federal funding; however, the Company still believes that utility-owned Charging Hubs can help accelerate fleet electrification in Michigan. The Company also explained previously that it added a criterion that federal funding be tied to any additional Charging Hub site that the Company constructs. This was added, in part, because the Company is uniquely suited to pursue federal grants and drive funding into Southeast Michigan. For example, the Company was instrumental in a Charging Hub in Redford Township receiving \$8.5 million of federal funding, and the Company has applied for federal funding for another Charging Hub in Southwest Detroit. If the Company is not granted approval to own additional Charging Hubs, then it will discontinue seeking similar awards, which could limit competitive federal funds in Michigan (Peterson, 4T 740-41, 801-802).

Staff “supports the idea behind the Emerging Technology Fund,” but finds it insufficiently

mature to make permanent (Freeman, 7T 4429). The Company disagrees because the Company has made significant progress on the Emerging Technology Fund (ETF) since the Commission's November 18, 2022 Order in Case No. U-20836. If permanency is rejected, then the ETF should at least be approved for another five years (through 2028) to maintain the already meaningful momentum and collaboration in progress (Peterson, 4T 803).

MNSC witness Jester recommended to require income-eligible EV rebates to be received at the point of sale (6T 3475). This recommendation is premature. Dealerships want the rebate to be integrated into the federal EV tax credit system. The system or process to apply the federal tax credit at point of sale is expected to be launched January 2024, at which time the Company could determine whether it is cost effective to integrate the EV rebate into the system. The Company disagrees with Mr. Jester's further suggestion to increase the EV rebate amount, because if the Company were to increase the rebate much more than its current \$1,500 amount, then it would exceed the low estimate of \$1,800 for the NPV that each EV would add to the grid over its lifetime (Peterson, 4T 804).

MNSC witness Jester (6T 3472-74) and MEIBC/IEI/United witness Sherman (6T 4187-89) made various recommendations for what the Commission should require the Company's TEP to contain or consider. These recommendations are premature because the TEP is still in development. The Company will engage stakeholders before filing the TEP by year end to inform final program design. This also addresses EVgo witness Stegall's recommendation (4T 1012) that the Commission direct the Company to host at least one stakeholder meeting (Peterson, 4T 805-806).

2. Delivered Fuel Electrification Pilot (DFEP)

DTE Electric proposes a five-year pilot to electrify space and water heating in homes currently heating with a delivered fuel, which includes propane, heating/fuel oil, diesel, or kerosene.

At full enrollment, the Company would facilitate the installation of approximately 1,500 air source heat pumps (ASHPs), 300 geothermal heat pumps, and 300 heat pump water heaters (HPWHs) (Peterson, 4T 761-62; Exhibit A-12, Schedule B5.10.1 summarizes how the DFEP meets the requirements of the February 4, 2021 Order in Case No. U-20645).

Ms. Peterson explained that heat pumps can provide benefits including monetary savings to customers from lower lifetime operating costs, and significant emissions benefits. There are barriers to adoption in Michigan, however, including: (1) higher upfront costs; (2) lack of customer and contractor awareness; and (3) limited incentives to convert to a heat pump. The Company's overarching objective is to help delivered-fuels customers unlock operational savings and environmental benefits from heat pump systems, while integrating the additional load in a manner that benefits all of its customers (Peterson, 4T 763-68).

Based on learnings from its prior efforts and feedback from stakeholders, the Company proposes the DFEP with three primary components: (1) Education and Outreach (E&O); (2) heat pump rebates; and (3) program management. If the Commission approves, then the Company will seek to launch the pilot within six months, and anticipates that it would last five years. The Company seeks the following key learnings: (1) heat pump identification capabilities via AMI; (2) heat pump adoption rates by region; (3) rated versus actual performance of heat pumps in cold climates; (4) customer and contractor perceptions and satisfaction with heat pumps; (5) refined cost-benefit analysis (CBA); and (6) the impacts to the grid. Similar to Charging Forward, the Company proposes to create and meet with a stakeholder group, and provide an annual status report to key stakeholders during the pilot (Peterson, 4T 770-76).

The Company requests a total of \$6.1 million over five years, as shown in the table at Peterson, 4T 776. Total projected DFEP spend for the projected test year is \$1.3 million (Exhibit A-12, Schedule B5.10, line 5, column (f)). The Company requests regulatory asset treatment for the duration of the pilot, which is consistent with the initial accounting treatment for the Charging

Forward and eFleets pilots (Peterson, 4T 776; Uzenski, 5T 1549).¹⁰²

The proposed DFEP benefits all customers in two key ways: (1) electric heat pumps have higher average cooling efficiency ratings compared to air conditioners, reducing overall load during DTE Electric's summer peak season, and (2) the increase in load seen by heat pumps occurs primarily during the off-peak season, when there is available capacity, and the additional usage spreads fixed costs. The Company estimates total net present value (NPV) gross margin benefit of \$11.3 million (based on average NPV gross margin of \$5,400 for each heat pump, and 2,100 heat pumps added due to the five-year program). Subtracting the program costs (\$5.0 million NPV) yields approximately \$6.3 million of overall NPV benefit (Peterson, 4T 777-78).

Staff indicated that "it is unclear how the cost of incremental power was determined" in the DFEP CBA, and suggested that the cost might not be accurate (Revere, 7T 4614-15). The cost of incremental power was determined by using base fuel and purchased power as PSCR Base. The PSCR Base is the fuel and purchased power cost included in the Company's tariffed rates, and the Company's tariffed rates are the basis for the revenue calculation in the CBA. Any other representation of the cost of fuel and purchased power would be an apples-to-oranges comparison (Peterson, 4T 806; Willis, 5T 3180; Exhibit A-13, Schedule C4).

Staff also recommended to forecast and include potential additional power supply and distribution costs associated with the DFEP CBA (Revere, 7T 4615). The Company disagrees because these additional costs are very difficult to forecast, and very unlikely to be significant at the scale of the proposed DFEP. The Company does, however, agree to work with Staff and Interveners to address perceived deficiencies prior to launch in 2024 (Peterson, 4T 807).

Staff indicated a concern that "the Company failed to properly justify the exclusion of customers currently heating with resistance heat or natural gas" (Revere, 7T 4615). This concern is

¹⁰² MNSC witness Neme suggested shortening the DFEP to three years, with a more aggressive ramp-up curve (6T 3501-3502). The recommendation is unnecessary and inappropriate because the Company has proposed regulatory asset treatment for DFEP costs, which has the benefit of flexibility in timing of spend to match program demand. The Company will adjust future year spend projections based on lessons learned after launch (Peterson, 4T 811).

misplaced for two reasons. First, since electric resistance customers transitioning to a heat pump decrease net load, they are already (and more appropriately) served with programs from the Company's Energy Efficiency team, so DFEP incentives would be redundant and not beneficial. Second, it is not economic to electrify homes heated with natural gas at this time, even with incentives, so it would not be prudent to spend limited resources on those customers (Peterson, 4T 808).

MNSC witness Neme correctly assumed the Company's definition of low-income customers for the DFEP (those participating in "any existing low-income program, including the Company's energy waste reduction (EWR) programs and bill payment assistance programs"), but he indicated a desire for broader coverage (6T 3503-3504). The Company is willing to modify the low-income definition for this pilot to align with the same eligibility criteria for the Charging Forward Income-Eligible EV Rebates (Peterson, 4T 809-10).

Witness Neme further recommended "to cover the full cost of new heat pumps for income-qualified households" (6T 3506). The Company disagrees because the rebates need to be sized to both incentivize adoption and manage pilot costs to ensure the incremental load provides a net benefit to all DTE Electric customers. The Company is willing to work with Staff and Intervenors to refine future rebate amounts to achieve the right balance between rebate levels and customer benefits (Peterson, 4T 810).

Witness Neme further recommended to "offer bonus rebates – i.e., dollars over and above what are available through its EWR programs – to non-low-income households that electrify their space heating" (6T 3512). The Company disagrees because customers are already eligible for building envelope efficiency rebates through the Company's EWR programs. Thus, increasing DFEP costs for EWR measures would be redundant and not beneficial (Peterson, 4T 810).

Therefore, the proposed DFEP pilot should be approved as proposed by the Company even while the Company continues to solicit input from stakeholders during the pilot.

3. Advanced Customer Pricing Pilot (ACPP) and 2023 Full TOD Rollout

The Commission approved the Company's ACPP in Case No. U-20162. Ms. Peterson supported ACPP costs relating to Customer Outreach, and Evaluation, Monitoring, and Verification (EM&V). For 2022 under the ACPP, the EM&V costs are \$0.2 million, but the Customer Outreach costs are \$0 because they transitioned from the pilot to the full TOD rollout program starting in 2022 (Peterson, 4T 784-86; Exhibit A-13, Schedule C5.9.2, lines 3, 5, and 10).

EM&V costs in 2022 (with no subsequent projection) supported administering surveys and ensuring that evaluation and analysis of this data will provide compelling, comprehensive, and insightful information as the Company progresses toward full TOD rollout (Peterson, 4T 784).

Customer Outreach will communicate the transition to full TOD rollout so all residential electric customers are informed that their base rate will be changed to a new TOD rate in March 2023. O&M expenses totaling \$2.8 million are needed in 2022 and 2023 because, based on lessons learned from the ACPP pilot, DTE Electric is preparing customers for the rate change by sending a series of communications via multiple channels (Peterson, 4T 785-86).

4. PrePay Pilot

In Case No. U-20836, the Company presented capital costs (\$8.0 million in the bridge period and \$4.6 million in the projected test year) for its proposed voluntary PrePay Program, but also explained that a decision on approval of the program was pending in Case No. U-21087. The Staff and AG objected to the costs as premature. The PFD stated:

This PFD finds Staff's analysis persuasive that the program will be evaluated in the separate docket, and if the company receives approval, which is uncertain given opposition in that case, it can then seek cost approval for the program. [U-20836 PFD, p 366.]

The Commission agreed, adding: "DTE Electric may seek these costs in a future rate case if and when the necessary approvals/waivers are eventually obtained." (Case No. U-20836 Order dated November 18, 2022, p. 206).

Although the Commission denied DTE Electric’s request to implement its PrePay Program as presented in Case No. U-21087, it found that the concept has merit and that the Company could refile its request as a proposed pilot, stating:

The Commission, however, finds that a prepay program could provide beneficial innovations for managing energy costs and consumption for certain customers if properly designed and vetted. Therefore, the Commission finds that DTE Electric may refile its request for a PrePay Program and associated waivers under the established objective criteria for approval of a pilot program and required comprehensive plan established by the October 29 [2020] order [in Case No. U-20645]. [Case No. U-21087 Order dated December 21, 2022, p. 17.]

Accordingly, the Company now requests approval for the implementation of its proposed voluntary PrePay Pilot, a waiver of certain MPSC billing rules (narrowed from the request in Case No. U-21087), and a recovery of \$6.7 million of capital expenditures in the 2021 historical period (Exhibit A-12, Schedule B5.7.3, line 51). The requested \$6.7 million recovery is justified because the Company already invested the \$6.7 million to build Phase 1 of its PrePay Program. This solution was deployed into the production CR&B system in December of 2021. The deployed solution includes all of the core functionality required to support a prepaid billing program, and can be used, with some configuration changes, to implement the proposed PrePay Pilot (Hatsios, 155-56).

The Company maintains that the historical cost of \$6.7 million should be approved, but withdraws its request to recover the \$2.6 million in the projected test year (Exhibit A-12, Schedule B5.7.3, line 52)¹⁰³. Some amount of investment might be required to modify the already-deployed solution to support the PrePay Pilot’s final design; however, the Company does not seek recovery

¹⁰³ The Company has provided its assessment of the cost to ratepayers of the proposed PrePay Pilot in Exhibit A-45, Schedule JJ3, which takes into account the impact of an already realized approximately \$4.4 million in depreciation, the cost of which is being borne by DTE shareholders. As seen in the referenced exhibit, the projected net book value of the project in November 2023 will be approximately \$2.3 million, and by November 2024, it will be approximately \$93,000. Therefore, the net average rate base included in the calculation of the revenue requirement would be approximately \$1.2 million, and the cost to ratepayers through revenue recovery would be approximately \$2.3 million. (5T 1786)

of these potential incremental costs in this case because they are not certain (Hatsios, 5T 1742-43, 1783-84, 1791).

In accordance with the Commission's directives in the U-21087 Order (quoted above), the Company provided all of the applicable objective criteria established in Case No. U-20645 for its proposed PrePay Pilot (Hatsios, 5T 1743-44; Exhibit A-24, Schedule N11).

The basic eligibility, structure, and management of accounts for the PrePay Pilot would be as described for Phase 1 of the proposed voluntary PrePay Program in Case No. U-21087; however, the Company considered the feedback that it received from Staff and intervenors, as well as the Commission's Order. Therefore, the proposed PrePay Pilot is designed to address, to the extent possible, their indicated concerns and recommendations, resulting in several differences from the PrePay program that was proposed in Case No. U-21087. Some of the more notable changes from the program proposed in U-21087 are an enrollment cap of 3,000 customers over a two-year period, the exclusion of seniors, a lower arrears threshold of \$250, an enrollment incentive, and extending the time to disconnect by 5 calendar days. (Hatsios, 5T 1744-48).

The Company has incorporated lessons learned from its own "Pay As You Go" pilot (offered from 2011 through mid-2015) and other utilities with prepaid billing. (Hatsios, 5T 1765). The PrePay Pilot's design is summarized by Company witness Hatsios at 5T 1766, with further details about key design attributes at 5T 1766-67 (Eligibility), 5T 1767-68 (Enrollment), 5T 1768-69 (Account Management & Notifications), 5T 1769-71 (Disconnection/Reconnection), 5T 1771 (Customer Feedback), and 5T 1771-72 (Unenroll).

Staff recommends "a total disallowance of \$9,344,000 in capital costs, with \$6,704,000 of that in the Historical Period ending 12/31/2021 (PrePay) and \$2,640,000 in the projected Test Year

ending 11/30/2024 (PrePay Phase II)” (Klocke, 7T 4551-52). AG witness Bunch similarly recommended a full disallowance of the program. (6T 3603).

Staff indicated that the “changes from the Company’s PrePay program as presented in Case No. U-21087 to this case has materially changed the program to a degree that Staff can no longer support such a program under the terms presented” (Klocke, 11). In addition to the discussion above, Mr. Hatsios addressed Staff’s concerns, further explaining the size of the program relative to its capital cost, (Hatsios 5T 1785-1787; Exhibit A-45, Schedule JJ3), the number of potential customers who could enroll in the Pilot and the possibility of easily increasing the arrears threshold (Hatsios, 5T 1787-1789), and the use of customer feedback and the Company’s own experience in developing the program (Hatsios, 5T 1789-1791).

The pilot is further justified because there is sufficient customer interest in prepaid billing. In addition, other utilities are offering prepay programs or pilots to their customers (Hatsios, 5T 1750-54; Exhibit A-24, Schedule N18 (PrePay Customer Focus Group Results); Exhibit A-24, Schedule N19 (PrePay Consumer Survey Data). Mr. Hatsios further described they types of customers who might benefit from the pilot:

The PrePay Pilot will provide all customers visibility and a greater sense of control over the energy they use and how much they spend, the ability to pay on a schedule that they establish and that better meets their needs, and a simplified billing experience. For customers who struggle to stay current on today’s monthly post pay billing model, prepaid billing will provide them the opportunity to pay in smaller amounts and at a frequency that aligns with their ability to pay, to easily monitor their usage, and to conveniently have a portion of each payment they make applied to the reduction of their arrears balance. [Hatsios, 5T 1754.]

The Company has identified four specific customer segments that it expects to benefit from the PrePay Pilot: (1) tech savvy energy conservers, (2) financially stable savers, (3) renters and college students, and (4) payment troubled and vulnerable customers (Hatsios, 5T 1755-58; Exhibit A-24, Schedule N12). Potential customer benefits include reduced energy usage, a manageable way

to pay down arrears, and ratepayer savings if the Pilot were to be expanded to 10,000 customers or more from reduced uncollectible expense and working capital that would be passed on in the ratemaking process. New customers beginning service with DTE Electric may also find the Pilot much easier to start service as compared to the traditional post-pay billing process (Hatsios, 5T 1759-64).

In addition to seeking approval of its PrePay Program in Case No. U-21087, the Company also requested a partial waiver of the Consumer Standards and Billing Practices for Electric and Gas Service, Mich Admin Code, R 460.101 *et seq.* (billing rules). The Commission did not reach this issue, explaining: “The Commission further finds that because it is denying DTE Electric’s PrePay Program application as presented, an evaluation of the requested waivers is unnecessary and might lead to confusion should DTE Electric choose to refile as a pilot program” (December 21, 2022 Order in Case No. U-21087, p 18).

The Company therefore is requesting waivers of billing rules to implement the PrePay Pilot. The rules and the applicable reasons for waivers are set forth at Hatsios, 5T 1772-73 (R 460.120(3)), 5T 1773-74 (R 460.129(4)), 5T 1774 (R 460.139(1)), 5T 1774-75 (R 460.139(6)), 5T 1775-76 (R 460.143(1)).

AG witness Bunch asserted that the Company did not explain how the requested waivers would be an “effective and efficient administration of the Rules” (6T 3606). To the contrary, Mr. Hatsios presented an extensive explanation in his direct and rebuttal testimony (5T 1772-77, 1792-93). It also bears emphasis that these are not the same waivers that the Company requested in Case No. U-21087. These waiver requests have been minimized as much as possible to address intervenor concerns about potential harms from the waivers requested in Case No. U-21087. The waivers requested in this case do not include notice of shut-off requirements. The main purpose of

the waivers is to allow all notifications to be allowed via links in e-mails and text communications (Hatsios, 5T 1776). Mr. Hatsios further summarized why the waivers and the proposed pilot should be approved:

The protections provided by the billing rules for which the Company is requesting waivers, are necessary in the post-pay model to help ensure customers are provided adequate opportunity to access funding, and if necessary, enroll in a payment plan to avoid shutoff. While this process plays out, today's post-pay customers continue to consume energy, adding to both their past due balance and their current amount due. For some customers, this cycle continues, over and over again, and still ultimately results in the disconnection of service for nonpayment.

The prepay model flips the script and gives customers who enroll in PrePay the opportunity to pay what they want, when they want, based on their financial situation and their energy needs. To assist customers, and to ensure they can successfully maintain a credit balance and avoid being disconnected, the Company will provide relevant information to the customer in the form of the previously described daily balance updates, low balance alerts, and easy payment options, which includes notifications letting the customer know that they can contact DTE for assistance if necessary to avoid shutoff.

Additionally, as described in the previously discussed PrePay Pilot eligibility requirements, the Company is excluding customers with a medical emergency at the premise, those with active military service, and any senior customers. Also, as described, the Company is adhering to the same disconnect rules that are in place today for post-pay customers (i.e., no shutoffs on weekends, or holidays, or during extreme weather). And finally, as I indicated, the PrePay Pilot is an optional program, customers can transition out of PrePay at any time with no penalty if they determine that the program is not providing them the benefits that they expected. [Hatsios, 5T 1776-77.]

AG witness Bunch asserted that the Company has decided to use "short-notice" disconnection as a "stick" and a "coercive" means to get customers to change their behavior (6T 3607). To the contrary, the Company designed the PrePay Pilot in a way that shows concern for customers by providing them with adequate time and options to avoid disconnection. All customers will receive low-balance alerts at 10, 5, 3, and 1 day prior to estimated exhaustion of their prepay credits. Customers will also have the option to receive daily balance alerts, and will have the ability to view their balance and the number of days remaining whenever they want, either online, through

the automated phone system, or by calling the dedicated PrePay Pilot phone number (Hatsios, 5T 1768-1769, 1794).

The Company has also committed to provide PrePay Pilot customers at least five full calendar days between the time they reach a zero balance and when their service is disconnected (up to seven days if the fifth day falls on a weekend or federal holiday). Therefore, at a minimum, every participant will have at least 15 days after receiving their ten-day low balance notification before they are disconnected. Plus, disconnection would only happen if they took no action to either replenish their account or request to return to post-pay billing, which they can do at any time (Hatsios, 5T 1770-1771, 1795).

The discussion above responding to Staff and the AG also applies to DAAO witness Koeppel's indicated belief that there are fundamental problems with prepaid billing, and criticisms of the pilot proposal (6T 4003-4008). Mr. Koeppel further asserted that "low-income customers may be the predominant segment served by such a prepay program" and that this reinforces his concerns about "this proposal harming low-income and other socially vulnerable people" (6T 4012-13).

The Company acknowledges that low-income customers could view a pre-pay program as an attractive alternative, but the Company has designed the Pilot to appeal and provide benefits to a variety of customer segments, and is not specifically targeting low-income customers. In fact, to enroll in the PrePay Pilot, a customer must contact the DTE Contact Center and speak with a PrePay specialist, which provides benefits including allowing the Customer Representative (CR) to validate the customer's low-income status and determine if the customer is eligible for any energy assistance that would help them pay down their past due balance, and to determine if the customer is eligible to enroll in the Company's Low Income Self-Sufficiency Plans (LSP) or the Payment Stability Plan

(PSP). Only after exhausting all of these available options, would the CR offer the customer the opportunity to voluntarily enroll in the PrePay Pilot (Hatsios, 5T 1754-57, 1796-97).

The PrePay Pilot also offers enrolled customers protections including 24/7 access to their PrePay account balance and number of days remaining, low balance alerts including relevant Company contact information and links to energy assistance information, all of the same information that is provided to customers in the post-pay noticing and disconnect process, and a five day grace period from the time a customer's PrePay account reaches a zero balance and the disconnection of service. (Hatsios, 5T 1768, 1797-98).

For all these reasons, most notably how the Company responded to concerns in U-20836 and U-21087, its PrePay Pilot should be approved. There is extensive evidence that PrePay is an attractive voluntary alternative for customers who wish to gain more insight and control over their energy usage, or who struggle with paying their bills with today's post-pay billing model. The Company further maintains that the capital expenditures are reasonable and prudent, and has provided significant details about the design of the pilot, customer segments that might benefit most from enrolling, eligibility requirements, adequate noticing prior to disconnection, and other areas of concern that have been addressed in light of Case No. U-21087. Therefore, the Company's proposed PrePay Pilot and requests for capital recovery and billing rules waivers should be approved.

C. Accounting Requests

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; (6) certain

Charging Forward costs; and (7) certain Advanced Distribution Management System (ADMS) costs. The Company also requests initiation of deferral treatment for certain costs of the Delivered Fuel Electrification Pilot (Uzenski, 5T 1503, 1561).

Also, the 2022 Inflation Reduction Act (IRA) provides for production tax credits (PTCs) related to nuclear power generation starting in 2024. The Company does not anticipate realizing any nuclear PTCs in 2024, but if any materialize (and going forward) the Company proposes that any nuclear PTCs be applied in PSCR proceedings instead of being reflected as tax expense in setting base rates (Uzenski, 5T 1558-59, 1561). Ms. Uzenski explained:

The value of the nuclear PTCs for DTE Electric is uncertain at this point and could fluctuate materially from year to year. If a forecast of the PTCs was reflected in base rates, either the customers or the Company could be harmed if actual credits turn out materially different from the estimate. To ensure customers receive the full benefit of the PTCs, the Company proposes to reflect the actual credits as an offset to fuel and purchased power expense in the PSCR reconciliation cases. This has the effect of a timely reduction in costs for customers because PSCR rates are reconciled and adjusted annually. [Uzenski, 5T 1559]

Finally, if the Commission approves the IRM (which it should as discussed above in section IX. B), then the Company proposes to record a regulatory liability for any over-recovery related to the IRM, using account 254, Other Regulatory Liabilities (Uzenski, 5T 1561).

D. Ford MIGreenPower (MIGP) Contract

In accordance with the settlement of the Company's Renewable Energy plan (REP) and Voluntary Green Pricing (VGP) cases (Case Nos. U-20713 and U-20851), DTE Electric filed an application requesting approval of a customer-requested special contract between DTE Electric and Ford Motor Company (Ford). The Commission granted the approval, and further ordered: "DTE Electric Company, in its subsequent general rate cases, shall file evidence demonstrating that the special contract with Ford Motor Company complies with the Commission's previous directives

regarding special contracts and Mich Admin Code, R 460.2031.” (Case No. U-21825, 12/21/2022 Order, p 6).

The cited rule concerns filing special contracts and is not relevant here. The Commission further explained that it had a concern about discounted special contracts being subsidized by other customers:

Speaking to cost allocation, the Commission found in that March 23 [1995 Order in Case No. U-10646] that, “unless [The] Detroit Edison [Company] can make a compelling showing why a different ratemaking treatment is justified, the Commission will not permit Detroit Edison to reallocate the costs of serving contract customers to other ratepayer classes.” March 23 order, p. 21. [Case No. U-21285 Order dated December 12, 2022, p. 4, n. 2.]

The special contracts in Case No. U-10646 provided discounts to General Motors, Ford, and Chrysler (now Stellantis) in exchange for their commitment to continue as customers. In contrast, the Ford MIGP does not provide a discount to the Company’s Rider 17 tariff, which is available to all DTE Electric customers (Crozier, 5T 2193-94). Therefore, there is no discount to even consider reallocating among customers.

There are some differences between the Ford MIGP contract and the Rider 17 tariff (for example, the Ford contract is a 35-year contract, but a Rider 17 contract can be as short as five years), but customers benefit from these differences. Ford’s obligation to a longer contract term, restricted termination period, and termination fees designed to mitigate any impact to other customers provides DTE Electric with an enhanced certainty of revenue recovery for the costs of the underlying assets compared to their Rider 17 customers (Crozier, 5T 2194-95).

The Ford MIGP contract will not affect cost allocation or base rates in this case. The revenues and costs for this contract, as with the Rider 17 revenue and costs, are all reconciled in the Company’s REP filings (Crozier, 5T 2195-96).

The Ford MIGP contract will not be subsidized by other customers. Ford will pay a levelized subscription fee designed to recover the revenue requirements for the final costs of the solar projects over the life of the contract. This is a well-established methodology that is also used to calculate other customers' subscription fees pursuant to Rider 17 (Crozier, 5T 2196).

In summary, although the Ford MIGP contract is arguably a "special contract," it should not be treated like the special contracts that the Commission approved in Case No. U-10646. Unlike the 1995 special contracts, the Ford MIGP contract (1) does not offer a discount to any established tariff; (2) uses the same methodology as an established tariff (Rider 17) to calculate revenue required from the customer; and (3) the revenues and costs do not currently flow through current or projected base rates. Therefore, the Commission should recognize that its directives and concerns about special contracts do not apply here (Crozier, 5T 2197).

Staff "recommends that the Commission deny the Company's request to not apply Michigan Administrative Code R 460.2031 or the Commission's prior special contract concerns to the Ford MIGP contract". Staff agrees that the "Ford MIGP contract does not purport to offer a discount," but reasons that it "Nonetheless offers different contract terms than those already approved by the Commission that adhere to cost of service principals" (Isakson, 7T 4479).

The Company maintains its position. As indicated above, the Ford MIGP contract has similar terms as Rider17, which is available to all customers. Any difference in the terms does not harm or disadvantage the broader DTE Electric customer base. When the Commission's directives were issued in Case No. U-10464, the contracts did not mirror an approved tariff like the Ford MIGP contract does. Therefore, The MIGP contract merits different treatment as the Company requests (Crozier, 5T 2232-33).

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 \$583 million in rate relief. See Attachments A and B.

X. COST ALLOCATION AND RATE DESIGN

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, including the cost-allocation methods approved in Case No. U-20836 (Maroun, 5T 3129, 3141-42; Exhibit A-16, Schedules F1.1 and F1.2).

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);¹⁰⁴ (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, 5T 3131).

The UCOS study contains 16 basic externally-developed allocation schedules (Maroun, 5T 3135). Company witness Asghar developed 11 allocation schedules for use in cost-of-service studies (see Exhibit A-5, Schedule E3 for a description of each schedule). She supported these allocation schedules as reasonable, and as accurately representing the load characteristics for

¹⁰⁴ 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, 5T 3131).

customers receiving power supply and/or distribution service from DTE Electric (Asghar, 5T 3169-72). Company witness Maroun used Ms. Asghar's allocation schedules, plus five more that he developed, to determine rate class cost responsibility (Maroun, 5T 3135).

Mr. Maroun explained how he functionalized DTE Electric's costs (5T 3131-33; Exhibit A-16, Schedule F1.3), and how the UCOS allocates costs to DTE Electric's various customer classes (5T 3133-36). He further testified that DTE Electric will experience a jurisdictional revenue deficiency of approximately \$618.5 million in the year ending November 30, 2024, consisting of a \$176.5 million base production revenue deficiency, and a \$442.0 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, Schedule F1.2 shows the distribution-related revenue (sufficiency)/deficiency by cost-of-service voltage class (Maroun, 5T 3137-38).

Staff proposed that "the most appropriate way to allocate the [EV program] costs is on overall revenue requirement (for distribution and power supply separately and in proportion to same), as that best represents the benefit from the downward rate pressure and is therefore the method Staff recommends the Commission approve" (Revere, 7T 4618).

The Company is concerned with this proposal because using proposed revenues by class would create a circularity problem in the COSS model, since allocated EV program costs by class are needed to calculate proposed revenues by class, which in turn is the allocator for the EV program costs. If the Commission agrees with Staff, however, then the Company recommends using present revenues (allocators 400a and 401) instead of proposed revenues. This would avoid the circularity problem while also functionalizing and allocating EV costs substantially as Staff proposed (Maroun, 5T 3157).

The Company proposes to continue using the same allocation methods for production and transmission that were approved in the November 18, 2022 Order in Case No. U-20836 (Maroun, 5T 3129, 3141-42). DTE Electric uses three allocation bases for distribution: (1) demand, (2) customer, and (3) those based on special studies.¹⁰⁵ 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 Signals¹⁰⁶), consistent with the allocation methods that the Commission approved in Case No. U-20836 (Maroun, 5T 3143). Exhibit A-16, Schedule F1.4 calculates monthly customer charges by voltage level, using the Staff method approved in the November 18, 2022 Order in Case No. U-20836 (Maroun, 5T 3146).

The Commission previously adopted the following changes to allocation methodologies: (1) MERC-plant and plant-related costs – allocated same as fuel costs; (2) fuel-handling O&M – allocated same as fuel costs; and (3) uncollectibles – allocated based on total revenue (November 18, 2022 Order in Case No. U-20836, pp 372, 373, and 385). The Company used those allocation methodologies in this case (Maroun, 5T 3142, 3145).

Exhibit A-16, Schedule F2 shows summarized present and proposed rate designs and corresponding revenues by rate schedule, and Schedule F3 shows rate schedule level detail of present and proposed revenues and resultant pricing. Exhibit A-16, Schedule F4 calculates typical

¹⁰⁵ 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, 5T 3144).

¹⁰⁶ Lighting is maintained as a separate class because it has a significant amount of dedicated infrastructure costs that should be assigned directly (Maroun, 5T 3144).

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 (Pollack, 5T 3115-16; Willis, 5T 3179, 3184, 3188, 3215). Mr. Willis summarized various changes to residential rates (5T 3185-3209). Mr. Pollack supported the Company's changes to commercial and industrial (C&I) rates (5T 3106-16). Further detail is discussed below in the context of the specific proposals.

B. Rider 10 Administrative Charge

The Commission previously ordered that “in its next general rate case, DTE Electric shall either file a proposal to eliminate the [Rider 10 administrative] charge, or, in the alternative, propose an administrative charge that is based on DTE Electric's cost to serve these Rider 10 customers, along with evidentiary support for this revised charge” (November 18, 2022 Order in Case No. U-20836, p 431). Accordingly, the only charges that are allocated to Rider 10 in the UCOS are (1) transmission expense, (2) voltage level service adder, (3) MISO pricing option costs, and (4) revenue deficiency/sufficiency and related tax gross-up. The allocation methodologies for other costs previously allocated to Rider 10 were modified to exclude the class from being allocated costs (Maroun, 5T 3142-43).

Staff took issue with the resulting negative Rider 10 administrative charge, suggesting that the Company did not comply with the U-20836 Order because the charge is not zero (Isakson, 7T 4476). To the contrary, the Company complied with the Order by zeroing allocation factors to eliminate allocations. There were still certain allocations to Rider 10, however, due to the change between present and proposed revenues (Maroun, 5T 3159-60; Willis, 5T 3226).

Staff asserted that “[t]he Company's proposed negative administrative charge is due to a proposed decrease in non-capacity power supply cost allocated to R10,” and recommended that “the administrative charge for R10 should be set to zero for the instant case with the remainder of

non-capacity power supply revenue requirement recovered through the MISO Energy charge” (Isakson, 7T 4476-77).

The Company disagrees that the MISO Energy Charge line is appropriate to account for the remainder if the administrative charge is zero because, by design, the MISO energy charge is held constant across present and proposed revenues on all rate schedules in which it is utilized. A better way to address Staff’s indicated concern would be through a simple modification to the COSS. A new line could be added to Exhibit A-16, Schedule F1.1 (between lines 24 and 25) in which the tax gross-up amount is negated from the R10 production revenue requirement calculation, and an equal and opposite amount is spread to all other rate classes. There would be zero net impact to revenue requirement, and the adjustment would eliminate the R10 negative administrative charge by having the R10 production revenue requirement equal its total costs. This proposal (along with correcting a small calculation error in the Company’s as-filed voltage level service adder) would yield a zero administrative charge without any change to the MISO Energy Charge line (Maroun, 5T 3159; Willis, 5T 3227).

Staff further recommended that the Commission should “direct the Company to file in its next general rate case actual data on the cost of administering Rider 10,” and suggested what that cost data might include (Isakson, 7T 4477). The Company disagrees. The non-zero number instead resulted from how the Company’s COSS was structured, and the COSS could be simply changed to produce a zero administrative charge as discussed above. In addition to being unnecessary , Staff’s proposal is also inconsistent with how the Company tracks costs and performs its COSS generally. Therefore, the Company’s proposal to modify the COSS to produce a zero administrative charge without modifying the MISO energy charge should be adopted, and Staff’s reporting recommendation should be rejected (Maroun, 5T 3160; Willis 5T 3228).

C. State Reliability Mechanism (SRM) Capacity Charge

Mr. Maroun calculated and explained the Company's capacity charge revenue requirement, which is reflected on Exhibit A-16, Schedule F1.5. He used the same methodology that the Commission approved in its November 18, 2022 Order in Case No. U-20836. 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, 5T 3147-52).

Mr. Burgdorf further explained the underlying calculations (5T 2066-73) and summarized that the total projected 2024 wholesale energy revenue of \$2.271 billion, net of \$1.204 billion in fuel-related costs, equates to \$1.066 billion wholesale energy sales revenue net of fuel costs as shown on Exhibit A-26, Schedule P3, Line 25. The reconciliation of the net sales benefit difference for 2021 of \$328.8 million (Exhibit A-26, Schedule P4, Line 12, column (d)) was subtracted from the 2024 projection, resulting in an amount of \$1.395 billion (Exhibit A-26, Schedule P3, Line 27) (Burgdorf, 5T 2072).

Energy Michigan witness Zakem recommended that "any expenses other than fuel should be removed from the 'net of projected fuel' calculation" (Zakem, 6T 4083. Emphasis omitted). The Company disagrees for a number of reasons that Mr. Burgdorf explained;

The Commission allowed the Company to include "Fuel-Related Costs" in Case No. U-20561 as these costs are all incurred as a result of the production of energy from the Company's generation resources. The Company continues to justify appropriate costs that should be included in the Fuel-Related Costs (e.g. emission allowance costs that are directly associated with the fuel and required by the Environmental Protection Agency) in the instant case to ensure all customers are treated fairly. The Commission has also deemed these Fuel-Related Costs as recoverable in the PSCR cases. If any of these costs were to be excluded from the Fuel-Related Costs category, then the Company's PSCR customers would be subsidizing customers paying the SRM Capacity Charge. Furthermore, the energy sales revenue would not be possible without incurring the Fuel-Related Costs necessary to produce the power to enable the sales, therefore, anyone receiving the revenue benefit should bear the associated cost. [Burgdorf, 5T 2076.]

Energy Michigan witness Zakem further proposed that the Commission “eliminate from a new SRM capacity Charge any “true-up’ of previous estimates as long as DTE has not applied the previous SRM Capacity Charge to any party,” presumably meaning an Electric Choice customer (Zakem, 6T 4088. Emphasis omitted). The Company disagrees because the enabling statute¹⁰⁷ does not say that its requirement to include a capacity charge true-up is contingent on whether an Electric Choice customer paid a capacity charge during the period being reconciled. Therefore, the energy sales net of fuel true-up must be included in the calculation of the capacity charge (Crozier, 5T 2234).

This ALJ also rejected Energy Michigan’s position in the Company’ last rate case, and the Commission agreed (U-20836 PFD, p 620; November 18, 2022 Order in Case No. U-20836, p 381). The decision was based on statutory construction, and remains appropriate.¹⁰⁸ It is axiomatic that statutory language must be applied as written.¹⁰⁹ Here, the statute (quoted above) is clear. In

¹⁰⁷ MCL 460.6w(4) states:

The commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in section (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year.

¹⁰⁸ The PFD relevantly states:

Focusing strictly on the text [of MCL 460.6w(4)], if the legislature had meant only that the “charge or credit” would be reflected in the capacity charge in the subsequent year, it would have been simple for it to say so, instead of using the term “the true-up.” This is consistent with Mr. Gottschalk’s testimony that the forward-looking charge should be reconciled to the actual results for the period within which it is collected. When DTE has not overcharged or undercharged anyone for capacity costs, there is no charge or credit to issue, but the true-up, i.e., the true-up net revenue, must be used in the mechanism for the subsequent period, using the same methodology. [PFD, p 620.]

¹⁰⁹ *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) (“We presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written”). *Hanson v Mecosta Co Road Comm’rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); *Amb’s v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003).

addition to the discussion above, for example, it repeatedly uses the term “shall,” which denotes a mandatory duty imposed by the Legislature and excludes the idea of administrative discretion.¹¹⁰

There is similarly no merit in Energy Michigan’s further suggestion that a load serving entity (LSE) that meets its capacity obligation to MISO under the MISO tariff should not be charged an SRM Capacity Charge (Zakem, 6T 4082). This suggestion doesn’t work because an SRM capacity charge is a retail charge that is billed to retail customers. The capacity charge is not billed to an LSE. Also, customers of an LSE will be billed for capacity by the incumbent utility if the LSE does not meet its capacity obligations under MCL 460.6w. The MISO capacity requirement is for the upcoming planning year, but the capacity demonstration required under MCL 460.6w is for the planning year four years out, so the capacity demonstrations are not the same (Crozier, 5T 2236-37. October 27, 2022 Order in Case No. U-21250 *et al*, p 28)).

The same response generally applies to Mr. Zakem’s related contention that MCL 460.6w “apparently envisions circumstances that became obsolete” due to MISO (Zakem, 6T 4093). Energy Michigan invites the Commission to “recognize” that the MCL 460.6w has “many flaws,” and therefore “administer an interpretation of the statute” according to Energy Michigan’s preferences (Zakem, 6T 4093). It is axiomatic, however, that the Commission cannot re-write the Legislature’s language to include new or different provisions.¹¹¹ Our Supreme Court has also recognized that, notwithstanding MISO, “the Michigan Legislature passed Public Act 341 to promote and ensure

¹¹⁰ *Macomb Co Rd Comm’n v Fisher*, 170 Mich App 697, 700; 428 NW2d 744 (1988); *Southfield Twp v Drainage Bd*, 357 Mich 59, 76-77; 97 NW2d 281 (1959) (“the word ‘shall’ is mandatory and imperative and, when used in a command to a public official, it excludes the idea of discretion”).

¹¹¹ *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”).

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.”¹¹²

Mr. Maroun further explained that he generally used the same methodology utilized by Staff in Case No. U-20836 to calculate the MERC revenue requirement; however, Staff’s calculation of the MERC revenue requirement in Case No. U-20836 incorrectly included the entire net plant value in addition to the return on and return of capital. Therefore, he corrected the calculation by removing the net plant value so that the calculation only included return on and return of capital, O&M (which was zero) and property taxes (Maroun, 5T 3148-49).

Mr. Maroun also reduced the capacity charge revenue requirement for non-capacity related purchased power (Exhibit A-16, Schedule F1.5, lines 3 and 4). He did so because these costs are for energy charges purchased from MISO for Rider 3 and Rider 10 (line 3) and other energy related purchased power (line 4) (Maroun, 5T 3149-50).

Mr. Maroun adjusted variable O&M (Exhibit A-16, Schedule F1.5, 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, 5T 3150-51).

The resulting total capacity charge revenue requirement is \$530.2 million (Exhibit A-16, Schedule F1.5, line 11). Mr. Maroun allocated it to the various rate classes using the 200B (4CP)

¹¹² *In re Reliability Plans of Electric Utilities for 2017-2021*, 505 Mich 97, 114, 128; 949 NW2d 73 (2020).

allocator excluding Rider 10, which is the methodology approved in Case No. U-20836 (Maroun, 5T 3151).

Energy Michigan witness Zakem suggested that the Commission should “require DTE to determine the SRM Capacity charge by season” (Zakem, 6T 4095). 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, 5T 2076-77; 5T 2235).

D. Residential Rate Design Proposals

Exhibit A-16, Schedule F3 shows the present and proposed rate designs and corresponding revenue by rate schedule. The Company proposes changes to the power supply designs of residential Rate Schedules D1.2 and D1.8 (Willis, 5T 3184, 3186). The Company also proposes a similar change to commercial Rate Schedule D1.8 (Pollack, 5T 3110).

The proposed residential power supply capacity and non-capacity rates were designed to recover the revenues pursuant to Witness Maroun’s Exhibit A-16, Schedule F1.5, 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 identifies 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 sufficiency was allocated based on each rate schedule’s percentage contribution to the present D1.11/Other power supply revenue. For those rate schedules with their own cost of service class (D1.2 11 and D2), the sufficiency 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-20836 (Willis, 5T 3185-3186).

Rate Schedule D1.2 is a product with rates that vary depending on season and time of day. Historically, the rate has had a flat non-capacity charge and time-variant capacity charges. Over time, the differential between the total on-peak and off-peak power supply charges has been maintained by varying the capacity charges. In this case, the allocated capacity and non-capacity revenue requirements are such that utilizing the existing design cannot maintain the historic relationships among the periods, and would yield negative off-peak capacity rates. Therefore, the Company proposes to vary non-capacity energy charges in the same manner as capacity energy charges, and thereby maintain the historical power supply relationships between the on-peak and off-peak pricing, while avoiding negative rates (Willis, 5T 3183, 3186-87).

Rate Schedule D1.8 is a dynamic peak pricing product that has three pricing periods based on time of day, and that is periodically subject to critical peak pricing. D1.8 functions similarly to D1.2, and currently utilizes power supply capacity charges to ensure appropriate time variance and relationships between the pricing periods. The capacity and non-capacity revenue requirements are such that the historical relationships cannot be maintained in the current design, minimizing its use as a time-of-use rate. Therefore, the Company proposes to vary non-capacity energy charges by time period, which will approximately maintain the historic relationships and the \$0.95/kWh critical peak power supply rate (Willis, 5T 3184, 3187).

In the Company's general rate case filed in 2014, Case No. U-17767, MPSC Staff recommended, and the Commission approved, variable distribution rates designed such that all customers in the Residential Secondary 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, and U-20836. The Residential Secondary rate schedules now all have the same distribution rate, so no cap is applied in this case (Willis, 5T 3187-88).

1. Rate D1.13, the Residential “Overnight Savers TOD” Tariff

The Company proposes to establish Rate Schedule D1.13 (Overnight Savers TOD), which has four key features: (1) it has three pricing periods; (2) it varies distribution, power supply capacity, and power supply non-capacity rates; (3) it is a voluntary rate that will be offered to residential customers; and (4) it is a whole-home rate that does not require additional metering (Willis, 4T 3189, 32150).

The Overnight Savers rate is an appropriate addition to the portfolio of rates that is available to customers because it is a cost-aligned option for low overnight pricing, it offers additional optionality to customers, and it is a more broadly accessible rate for customers seeking low overnight pricing, such as those who own or lease electric vehicles (EVs). The success of Rate Schedule D1.9 (the Company’s supplemental EV charging rate) established that customers desire low overnight rates for EV charging (and potentially other things). The Company’s primary offering that delivers on this desire without critical peak pricing requires a second meter, which might discourage or preclude customers from taking service. Customers that cannot leverage D1.9 but could use D1.13 Overnight Savers include renters, customers in multifamily dwellings, and customers who are interested in EV ownership (and particularly those leasing an EV) but do not want to make the cost commitment of new wiring and a second meter (Willis, 5T 3189-90, 3192, 3194). Overnight Savers is intended in part as a successor to D1.9, and the Company expects that a relatively high proportion of Overnight Savers customers will have EVs (Willis, 5T 3197-98).

Overnight Savers has three pricing periods: (1) On-Peak (3:00pm – 7:00pm weekdays); (2) Super Off-Peak (1:00am – 7:00am all days); and (3) Off-Peak (all other hours). The on-peak pricing

period is designed to be consistent with Rate Schedule D1.11 (default time-of-use rate). The super off-peak period is designed to align with the Company's lowest load hours from both a system and residential customer perspective. This period is a critical part of the proposal because it is a rate option for highly-engaged customers who have the ability and desire to shift load into overnight hours, or add load in overnight hours (Willis, 5T 3191-92).

Overnight Savers offers cost-aligned pricing for all load on one rate, which balances lower overnight (super off-peak) pricing with higher daytime and peak pricing. The resulting rate is designed to be revenue neutral to D1.11. Thus, the rate maintains overall cost alignment and revenue neutrality, while offering low overnight pricing (Willis, 5T 3185, 3193).

The proposed design varies pricing based on observable market and system characteristics. Power supply capacity and non-capacity prices vary depending on the ratio of the LMPs across the pricing windows, which is the same methodology used for Rate Schedule D1.11, and conveys to customers the economics of power supply and when costs are higher. Distribution prices vary depending on average residential substation loading, which is a measure of relative grid demand (Willis, 5T 3190, 3194-97).

The Company anticipates that the Rate Schedule D1.13 will drive changes in usage patterns compared to D1.11 due to a relatively high proportion of customers charging EVs during super off-peak hours. The present assumption is that super off-peak usage would increase 5%, with those sales proportionally reduced from the off-peak and on-peak periods. Actual usage patterns might differ, however, and there is some uncertainty due to the lack of a comparable rate offering. Therefore, the Company proposes to limit D1.13 enrollments to 10,000 customers. Assuming that Rate Schedule D1.13 is approved, the Company plans to have it become effective during the projected test year upon system implementation (Willis, 5T 3197-98).

Therefore, the Company's proposed Rate Schedule D1.13 (Residential Service Rate – Overnight savers TOD) should be approved.

2. Rate Schedule D1.6 Transition and Closure

The Company proposes to change the Low-Income Assistance (LIA) program by eliminating Rate Schedule D1.6 (which offers qualifying low-income customers a \$40 per month credit on their bills) and transitioning all D1.6 customers to D1.11. The Company also proposes to expand the availability of the LIA credit to all residential base rates, including D1, D1.11, D1.2, D1.8, D2, and the proposed D1.13. This change will have no substantive impact on the credit, and will bring the LIA availability in line with how the electric Residential Income Assistance (RIA) program is managed (Griffie, 5T 2096; Willis, 5T 3200-3203, 3215).¹¹³

The Company also proposes to expand its senior provision (now available on only rate schedules D1 and D1.11) so that it is available to all residential base rates. This would support customer flexibility and optionality. After the change, customers could utilize the credit on D1, D1.2, D1.8, D1.11, D2, and the proposed D1.13 (Willis, 5T 3203, 3215).

The Company essentially agrees with Staff's recommendations regarding the timing for filing D1.6 and D1.13 tariffs (Isakson, 7T 4482), and believes that it is prudent to (1) file the tariffs on the typical 30-day post-order timeline, and (2) with additional language noting their effective dates as no later than November 30, 2024 (Willis, 5T 3225).

DAAO witness Koepfel did not support the Company's proposal to transition D1.6 customers to D1.11, and expand the availability of the low-income assistance credit, asserting that "the forced conversion of LMI customers onto the D1.11 TOD rates raises equity and customer

¹¹³ The RIA provision provides a \$8.50 per month credit for qualifying customers, which offsets the current \$8.50 monthly service charge (Griffie, 5T 2092).

education concerns” (6T 4002). The Company disagrees because there is no sound basis for Mr. Koeppel’s indicated concerns. A customer receiving (or who desires to receive) the credit must take service on Rate D1.6 (regardless of whether the customer wants that rate schedule) and presently has no alternative option. The Company’s proposal to open the LIA credit to all base rates supports customer choice and flexibility. Mr. Koeppel does the opposite by essentially proposing that customers be forced to stay on (or move to) Rate D1.6 as a condition of receiving the credit (Willis, 5T 3245-47).

The Company’s proposal to close rate D1.6 is also appropriate because the Commission has made it clear that the Company should be oriented toward time-of-use rates for residential customers. Rate D1.6 customers are the only customers (apart from those without transmitting meters and customers on Rate Schedule D2 which has been closed to new customers since 2015) who remain on the inverted block rate. Rate D1.6 was established as the vehicle for the LIA credit simply because that rate design mimicked the default (D1) residential rate at the time. The default rate is now time-of-use, so that is the most appropriate rate design going forward (Willis, 5T 3246-47).

Mr. Koeppel also recommended an “analysis from DTE on the impacts of TOU conversion on LMI households” (6T 4022). The Company disagrees because the recommendation ignores the extensive record of D1.11 in prior cases, and the reality that it is the default rate for nearly 2 million customers. The study would also be onerous to conduct, and provide little, if any, determinative value (Willis, 5T 3247).

3. Rate Schedule D1.7 (Geothermal Time of Day).

Staff found that the Company’s proposed rate design (which is consistent with the approved rate design in Case No. U-20836) “produces a reasonable set of charges when it relies on the

Company's proposed revenue requirement and COSS" (Isakson, 7T 4466). Based on Staff's proposed revenue requirement and COSS, however, the Company's proposed method results in negative capacity charges as a result of balancing the total power supply revenue requirement. "To correct this issue Staff instead allocated the power supply capacity revenue requirement to each of D1.7's four distinct charges based on the present revenue that each charge generates" (Isakson, 7T 4467).

The Company agrees that Rate D1.7 should not have negative capacity rates in any of the pricing periods, and that negative D1.7 rates are the mathematical outcome using the Company's rate design with Staff's proposed revenue requirement and COSS. The Company disagrees with Staff's proposed rate design, however, because it largely eliminates the time variant nature of the rate relative to the Company's proposal and the Orders in Case Nos. U-20561 and U-20836. Therefore, the Commission should order a D1.7 design that approximates the historic ratio, or in the alternative, a design that reflects gradualism instead of the significant reduction in the summer differential as proposed by Staff (Willis, 5T 3223-24).

E. Commercial Secondary Rate Design Proposals

DTE Electric's commercial secondary rate design is consistent with the methodology that the Commission approved in past cases. The Company proposes changes in commercial D1.8 consistent with those for residential D1.8, discussed above. The Company also proposes to change Rate Schedule D4 (the Company's large general service rate). Within power supply, all capacity costs are recovered through a demand charge, and a portion of non-capacity costs are also recovered through a demand charge. The balance of the non-capacity costs are recovered through energy charges. The Company proposes to limit the change in the ratio of demand and energy charges for D4 power supply to no more than 15% compared to the currently-effective rates. This change is to

ensure that customers on the rate are not subject to excessive volatility in how they are charged (Pollack, 5T 3108-10).

Staff disagreed with the Company regarding Rate D4, and proposed to “maintain the current ratio between demand and energy revenue collection of roughly 53% demand and 47% energy (i.e. not ‘limit’ the change between the two). (Isakson, 7T 4474). The Company notes for clarity that the current ratio is 47% demand and 53% energy, and maintains its position (Pollack, 5T 3119). The Company utilized a similar method to what was approved in Case No. U-20836. The only change from currently approved rate design is the limit placed on the shift of power supply demand-based recovery to power supply energy-based recovery (Pollack, 5T 3120).

Staff proposed to modify distribution cost allocation in such a way that, in this case and with Staff’s proposed revenue requirement, \$70 million of distribution cost recovery would be moved from residential customers to commercial secondary customers. To lessen the effect of this change occurring all at once, Staff further proposed an Interim Distribution Alignment Credit/Surcharge (IDACS), which would be a credit to residential and a surcharge to commercial secondary for the duration of the projected test year (Isakson, 7T 4458-59). The Company does not take a position on Staff’s proposed change in allocation methodology; however, the proposed IDACS presents challenges (customer understanding, timing, and cost). Therefore, if the Commission adopts Staff’s proposed change to distribution allocation methodology, then the Commission should adopt the full value of the change in this case. This would create the least risk of customer confusion resulting from temporary credits, surcharges, or other methods of staggering the implementation of the change. In the alternative, the Commission should implement 50% of the change in this case, and 50% in the next rate case. This would be consistent with Staff’s stated goal of gradualism, and work

within existing billing IT structures and processes (Willis, 5T 3221-22). As Company witness Willis observed:

“The Company cannot achieve the proposed timing and is simply not able to construct the billing mechanism in the IT system in the seven days it typically utilizes for rate implementation following an order in a general rate case. Given the proposed short term nature of the IDACS (ending at the conclusion of the projected test year), the IT development would consume a potentially significant portion of that time.” (Willis 5T 3221)

F. Commercial and Industrial Primary Rate Design Proposals

Mr. Pollack described the Company’s major primary rate schedules,¹¹⁴ and explained that Rates D11 and D6.2 have both demand-based and energy-based rates. Within power supply, all capacity costs are recovered through a demand charge, and a portion of non-capacity costs are also recovered through a demand charge. The balance of non-capacity costs are recovered through energy charges. The Company proposes to limit the change in the ratio of demand and energy charges for D11 and D6.2 power supply to no more than 15% compared to the currently-effective rates. This change is to ensure that customers on the rate are not subject to excessive volatility in how they are charged (Pollack, 5T 3112-13).

Regarding Rates D11 and D6.2, ABATE witness Andrews asserted that “DTE’s proposed rate design would cause a very large portion of the recovery of power supply revenues from customers in the primary classes with demand charges to be shifted from demand charges to energy

¹¹⁴ 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. Rider 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 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 (Pollack, 5T 3112-13).

charges.” He further asserted that this caused the Company “to propose to mitigate the amount of the shift,” and that the “cause of the large shift is DTE’s use of the SRM Capacity Charge revenue requirement in its rate design and the large downward swing in DTE’s SRM Capacity charge revenue requirement in this proceeding due to abnormally high market prices for energy” (Andrews, 4T 1085). Based on this, he proposed to either utilize “an analysis based on DTE’s 2024 power supply cost components” to obtain a 62% demand / 38% energy split of costs, or in the alternative that “the current primary class split of 47% demand and 53% energy be maintained” (Andrews, 4T 1095-96).

The Company disagrees. The Company’s only change from currently-approved rate design is the limit on the shift of power supply demand-based recovery to power supply energy-based recovery, which would reduce volatility and be in accordance with the principle of gradualism, as indicated above. Using Rate D11 as a further example, the current ratio using rates approved in Case No. U-20836 is 47% demand / 53% energy. Using the identical method in the instant case, the ratio would be 23% demand / 77% energy, so the Company’s proposed limit is appropriate. In contrast, Mr. Andrews’ primary recommendation is to use his analysis of power supply cost types to determine demand and energy charges. This would represent a stark departure from how cost of service and rate design have been conducted. Therefore, the Commission should reject ABATE’s proposal to use power supply line-item costs as a basis for determining a demand/energy split in rate design, and adopt the Company’s proposal to limit the percentage change in the ratio of demand to energy in any one case to 15% on any given rate schedule (Pollack, 5T 3120-21).

The Company’s proposed primary delivery rates are cost-based by voltage level, as reflected on Exhibit A-16, Schedule F1.2. All primary rates will have the same \$/kW charges shown in column (h), except Rate D10 and Riders R1.1 and R1.2, which have energy-based delivery

charges. Mr. Pollack calculated energy charges for these rates that are equivalent to the proposed voltage level distribution charges (Pollack, 5T 3114-15).

1. Rate Schedule D13

Rate Schedule D13 is the Company's XL Industrial High Load Factor rate for customers with new load of at least 50 MW of contract capacity at a 75% load factor. The Commission approved the rate (December 22, 2021 Order in Case No. U-21163). The proposed rate design is consistent with the design approved in Case No. U-21163, and utilizes the Blue Water Energy Center (BWEC) as a proxy indication of marginal cost to serve. The proposed rates use updated assumptions. Customers taking service on D13 are not subject to the PSCR factor; however, consistent with Case No. U-21163, D13 is subject to true-up to reconcile actual natural gas prices with the gas prices assumed in approved rates. This ensures that D13 customers continue to be responsible for their cost of service. D13 customers are similarly subject to a reconciliation of transmission expense (Willis, 5T 3207-3209). The Company proposes to use the same methodologies detailed in Case No. U-21163, and as reflected in Exhibit A-16, Schedule F3, to allocate D13 revenues (Maroun, 5T 3138-40).

2. Rider 3

In Case No. U-20836, this ALJ agreed with DTE Electric and Staff that Bloom Energy's recommendations concerning Rider 3 should be rejected (PFD, p 685). The PFD further stated (after recounting reasons for rejecting Bloom's recommendations):

That said, the PFD finds that in the company's next rate case, DTE should be directed to provide a proposal to reduce the reservation fee for fuel cell systems, based on FOR [forced outage rate] for these systems, or provide a justification for why it would be unjust or unreasonable to do so. [PFD, p 685.]

The Commission agreed, stating that it was “persuaded by the testimony presented by the company and the Staff that Bloom Energy’s recommendations for the Rider 3 tariff are not reasonable at this time . . . [but] the Commission adopts the ALJ’s recommendation and directs DTE Electric to file in its next rate case, a proposal to reduce the reservation fee for fuel cell systems, based on the FOR for these systems, or provide justification for why it is unreasonable to do so” (Case No. U-20836 Order dated November 18, 2022, pp. 427-28).

Accordingly, Mr. Willis further explained that consistent with the Orders in Case Nos. U-20836, U-20561, and prior cases, it is unreasonable to reduce the reservation fee for fuel cell systems. Rider 3’s generation reservation fee already reflects the forced outage rate of the best performing generator, based on the adoption of ABATE’s proposal in Case No. U-18255. Thus, the Rider 3 generation reservation fee has consistently included a best-performing-generator FOR adjustment since the April 18, 2018 Order in Case No. U-18255 (Willis, 5T 3210, 3250).

The Company does not custom-design rate schedules or riders based on the operating characteristics of individual customers. Rate design based on the average energy usage characteristics of customers is a well-established feature of utility ratemaking. As indicated above, the generation reservation fee is already based on the forced outage rate of the best performing generator. Rider 3 appropriately applies to any customer with a common set of characteristics, and has pricing based on the aggregate of those customers. Fuel cells are just one of the myriad technologies that might be employed by the Company’s customers. An asserted incremental difference in forced outage rate does not make them somehow qualify for unique treatment (Willis, 5T 3211-13, 3251, 3255-56).

Bloom witnesses Morse (6T 4101-12) and Jester (6T 4119-38) largely recounted their testimony from Case No. U-20836 attempting to obtain favored treatment for Bloom technology,

and otherwise continued to offer no valid support for their positions. Company witness Willis responded in detail (Willis, 5T 3248-56), which is incorporated in full rather than being repeated here, since the Company already litigated this matter extensively in Case No. U-20836. Staff also again found that Bloom's contentions should be rejected, while further noting the lack of evidentiary support provided by Bloom for their positions in the instant case (Revere, 7T 4636-39, 4641-42). The Company further notes that although *res judicata* and collateral estoppel do not apply "in the pure sense" to MPSC decisions, issues fully decided in earlier MPSC proceedings need not be relitigated in later proceedings unless a party presents new evidence or shows by changed circumstances that the earlier result is unreasonable.¹¹⁵

Therefore, and in addition to the prior record and rejection of Bloom's proposals in Case No. U-20836, it would be unjust and unreasonable to reduce the reservation fee for fuel cell systems or adopt the other unsupported positions of Bloom.

G. Streetlighting Rate Design

Community Lighting provides Commission-approved tariff service to approximately 166,000 street lights on its E1 Option I Rate Schedule, 138 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, 5T 2617).

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 mercury vapor, high pressure

¹¹⁵ *Application of Consumers Energy Co*, 291 Mich App 106, 122; 804 NW2d 574 (2010); *Pennwalt Corp v Public Service Comm*, 166 Mich App 1, 9; 420 NW2d 156 (1988).

sodium, metal halide, and light emitting diode (LED) 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 (Bellini, 5T 2617-20). 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, 5T 2620-21).

Exhibit A-16, Schedule F3 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-20836 reflect a monthly energy charge, both non-capacity and capacity energy, and a luminaire charge (Bellini, 5T 2637-39).

Mr. Bellini supported the proposed allocation of costs reflected in the various E1 Option Rate Schedule luminaire charges (5T 2639-42), 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, 5T 2642). 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, 5T 2642-44). The Company's proposed D9 rates similarly

allocate costs and continue the gradual movement toward cost-based rates (Bellini, 5T 2644-45). Mr. Bellini also explained and supported Rate Schedule E2 charges (5T 2645-46).

MI-MAUI witness Bunch proposed that the E1 streetlighting tariff be amended to provide that the Company issue to any E1 requesting streetlighting customer an annual report (or quarterly report for customers with more than 5,000 lights) providing streetlight outage occurrence counts, average outage duration, and counts of outages lasting longer than 14 days (4T 933-34). The Company disagrees because its outage management system (OMS) does not have this capability. The Company does not capture customer-reported outages by light, but instead by event (which could be many lights). Implementing the proposal (which would be inappropriate) would also likely involve costs that would have to be passed on to customers (Bellini, 5T 2665-66; Exhibit A-40, Schedule EE10). Mr. Bunch’s premise, that the Company “avoid[s] accountability for reliability of its streetlight services” as he suggests in a question to himself (4T 927) is inaccurate. The Company continues to be transparent in its performance, and will continue to evaluate and employ solutions to improve reliability and reduce outages. For example, the Company proactively implemented a night patrol program in 2019, and proactively implemented its cable replacement program effective in 2022 (Bellini, 5T 2628-29, 2667). Therefore, the proposal to modify the E1 streetlighting tariff should be rejected as impractical and unfounded.¹¹⁶

MI-MAUI witness Bunch also suggested that the Company opposes streetlight outage credits (e.g., 4T 935). To the contrary, the Company has not denied any streetlight customer outage credit requests in 2022 (Bellini, 5T 2668; Exhibit A-40, Schedule EE11). Mr. Bunch went on to suggest various outage criteria and reporting requirements (4T 936-37). These are unnecessary and

¹¹⁶ To the extent that Mr. Bunch’s proposal that the Company “include outages discovered by night patrols in its reports” (4T 934) pertains to aggregate outage detail reflected in Exhibit A-40, Schedule EE3, the Company agrees and will do so effective 2024 (Bellini, 5T 2668).

impractical, with steps suggesting that multiple new reports would need to be created for which data does not even exist. In contrast, presently (unless the Company is impeded from making a timely repair) outage credits are generally issued within the next billing cycle. The proposal should also be denied because, as discussed above, the Company's outage performance does not merit such onerous criteria. The standard duration for an outage was 4.7 days in 2022, despite almost 3,000 events being "ok on arrival" or the pole and/or light was knocked down by a third party (Exhibit A-40, Schedule EE3). Also, not all outages are the result of failed Company equipment, and when the Company is impeded from making a repair, these additional 1,931 "follow-up" events in 2022, added over 2.5 days (over 50%) to the Company's restoration time for a total of 7.24 days (Exhibit A-40, Schedule EE3, line 9). Therefore, the Commission should reject the MI-MAUI streetlight bill credits proposal (Bellini, 5T 2669-70).

MI-MIUAUI witness Bunch further suggested that the Commission "order DTE to reduce the electric sales forecast for streetlights for the projected test year by 4,508,803 kWh, or approximately 3.25%, and to reduce the revenue requirement for streetlights accordingly" (4T 940). The Company disagrees because, as indicated above, not all outages are the fault of Company equipment, and those outages for which the Company is impeded from making a timely repair add approximately 2.5 days (over 50%) in outage duration. Also, the adjustment would theoretically account for outages for which credits are paid (and Mr. Bunch suggests further credits), resulting in double compensation. The most equitable solution continues to be the Company's current process of evaluating each customer-requested outage credit for reasonableness and issuing approved credits directly to the municipality. Therefore, MI-MAUI's proposal to reduce the streetlighting sales forecast should be rejected (Bellini, 5T 2670-71).

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. 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 \$38.9 million for the projected test period (Exhibit A-20, Schedule J1, page 1, line 5, column (b)), which is a decrease of approximately \$0.2 million from the currently-authorized nuclear surcharge. The Company's proposed nuclear surcharge is reasonable and prudent, and therefore should be approved (Davis, 5T 2497-98. See also Willis, 5T 3182; 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 approved by the Commission. 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, 5T 3204).

Staff (Matthews, 7T 4566), MEIBC/IEI/United witness Sherman (6T 4181), and DAAO witness Koepfel (6T 4046) suggested that the Company should voluntarily raise or eliminate the

limits on installed capacity allowed under the Company's DG program.¹¹⁷ To the extent anything remains of this issue (which would be unexpected in light of the Commission's Order Approving Settlement in Case No. U-21193),¹¹⁸ the Company acknowledges that DG program and tariff design has been subject to disagreement among various stakeholders, but maintains that the current design of Rider 18 creates an unfair cost shift from DG customers to non-DG customers. Limiting the amount of DG capacity that can take service under Rider 18 can offer useful protection against these cost shifts. As discussed in pending Case No. U-21376,¹¹⁹ if the Company elects to limit participation in its current DG program, customers will have other options under which they could connect their DG systems and take service. The Company also made a commitment in Case No. U-21376 to continue accepting applications for Category 1 systems through at least the end of 2023 (Foley, 2T 107).

Mr. Koepfel recommended that the Company increase the Rider 18 outflow credit or provide incentives for low and moderate income (LMI) customers wishing to install DG (6T 4047-48). The Company disagrees because increasing the Rider 18 outflow credit and/or introducing an LMI incentive for solar adoption would only increase the size of the unfair cost shift from DG customers to non-DG customers (who would have to pay for the higher credits or new incentive through higher rates, which the Company does not consider appropriate).

¹¹⁷ MCL 460.1173(3) relevantly provides: "An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years."

¹¹⁸ On July 26, 2023, the Commission issued an Order Approving Settlement Agreement in Case No. U-21193.

¹¹⁹ The November 18, 2022 Order in Case No. U-20836 directed the Company to file options available to customers with DG systems should DTE Electric decide to cap participation in its current DG program consistent with MCL 460.1173(3).

J. Rider 14

As discussed above in section IX. A. 1, the Company proposes certain rate book modifications as part of its permanent program proposals for Charging Forward. Rider 14 is further discussed here because the proposed expanded availability goes beyond electric vehicles.

Rider 14 provides for the payment for energy that outflows from customers to the Company. The Company proposes three changes to expand Rider 14's availability and capacity (Willis, 5T 3205-3207).

First, Rider 14 is currently available to Rate Schedules D1, D3, and D4. The Company proposes to expand Rider 14's availability to all full service customers, except where noted on the customer's applicable tariff. Rider 14 would remain inapplicable on any other service or rider. This change would expand customer optionality in how they manage their energy (Willis, 5T 3205).

Second, Rider 14 is: "Available to customers with on-site distributed generation desiring to operate in parallel with the Company's system and take service for their supplemental needs." The Company proposes to amend the tariff to include battery electric vehicles and stationary storage. The addition of battery electric vehicles will support future vehicle-to-grid applications. The addition of stationary storage will allow customers to have more flexibility in utilizing their assets (Willis, 5T 3205-3206).

Third, the Company proposes to increase the capacity limit from 100kW to 150kW to better align the capacity limitations across existing programs and products offered by the Company, such as the current DG program (Willis, 5T 3206).

MEIBC/IEI/United witness Sherman (6T 41555-56) and MNSC witness Jester (6T 3468) proposed that storage outflow should be compensated at full retail rates. The Company disagrees because Rider 14 is available to a wide variety of technologies, and the Company's proposal extends that availability to storage. It would be inappropriate to alter the rate design that applies to the

various technologies supported on Rider 14. The currently-approved Rider 14 is an LMP-based rate with customer compensation designed to reflect the power supply costs avoided by the Company for their outflow. This framework of closely linking compensation and avoided cost is correct. The proposals to provide retail credits for storage outflow have no cost basis and would generate unjustified profits for certain customers. They also inaccurately imply that charging and discharging storage do not utilize the grid, and there is no cost responsibility for grid operation and maintenance. Thus, the proposals are nothing but requests for a subsidy without justification or legal authority¹²⁰ (Willis, 5T 3232-3234). Staff also notes their own disagreement with the proposal put forth by witness Sherman and witness Jester (Krause, 7T 4538-39).

Therefore, the Commission should (1) adopt the Company's proposal to amend the applicability and availability of Rider 14 as proposed, including the addition of storage as an eligible resource, and (2) reject the proposals to provide full retail credits to storage outflow, which improperly focus on certain customers making profits instead of cost-based ratemaking (Willis, 5T 3234).

K. Other Proposals

1. DR Tariffs

MEIBC/IEI/United witness Schisler made three recommendations regarding DR tariffs. First, that the Company should include language in the Company's DR tariffs that specify which

¹²⁰The 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).

tariffs are ineligible for Aggregator of Retail Customers (ARCs) participation (Schisler, 6T 4260). The Company agrees with the concept and proposes to add the following language to interruptible tariffs (D1.1, D3.3, D5, D8, R1.1, R1.2, R10 and R12): “Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC).” Adding this language will ensure that the February 23, 2023 Order in Case No. U-21099 *et al* is followed (Farrell, 5T 1335-36).¹²¹

Mr. Schisler’s second recommendation (based on an unfounded anti-competitive “tying arrangement”) was to “unbundle” DR tariffs (separate wholesale DR from retail DR), and “allow customers to choose 1) a wholesale demand response offering from DTE, 2) a retail DR offering from DTE, or 3) both” (Schisler, 6T 4265). The Company’s DR programs are designed for its retail customers and used at the wholesale/MISO level to support the reliability of the bulk electric system. Since the programs are only designed for retail customers, there are no DR tariffs that would need to be separated into wholesale and retail. The retail benefits provided in the Company’s DR tariffs are made possible by the resource adequacy benefits that the Company receives from MISO. Mr. Schisler’s proposal suggests that the Company should provide the retail DR benefits without receiving the wholesale benefits or receive the wholesale benefits at a marked-up price to provide profits to ARCs. This is unjustified and would be detrimental to the Company and its customers. Moreover, nothing prevents ARCs from marketing their services to customers, as long as they comply with the Commission’s orders in Case No. U-21099 *et al* and any applicable requirements from MISO. Therefore, Mr. Schisler’s second recommendation should be rejected (Farrell, 5T 1337-38).

¹²¹ 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’s February 23, 2023 Order in Case No. U-21099 *et al* provided some additional clarity, including that certain customers will not be allowed to participate in aggregated DR programs.

Mr. Schisler's third recommendation was to create a Demand Response Feed in Tariff (DR FIT) under which "the utility purchases the DR capabilities [Zonal Resource Credits (ZRCs)] of its customers represented by an ARC" (Schisler, 6T 4267). The Company disagrees because it can already purchase ZRCs from a third-party within MISO's Module E Capacity Tracking tool (MECT). There would be no benefit in adding a tariff to the process that is already in place within MISO. Therefore, witness Schisler's third recommendation is unnecessary and should be rejected (Farrell, 5T 1339).

Mr. Schisler suggested to "create an option for an ARC to enroll customers in the DTE retail demand response tariff-based program. This approach would leverage the customer recruitment and enablement efforts and expertise of ARCs to bring customers into the DTE retail program" (Schisler, 6T 4265). The Company disagrees because this is unnecessary and could be problematic. The Company already has the largest DR portfolio in MISO, so it has done an excellent job in recruitment. The Company also has direct communications with its customers. Allowing ARCs to recruit customers to enroll on the Company's DR programs could result in customer confusion. Therefore, the suggestion should be rejected (Farrell, 5T 1338).

2. Performance-Based Ratemaking (PBR)

AG witness Coppola proposed a Service Improvement Incentive Mechanism (SIIM) consisting of ten equally weighted Target Metrics that would be used to calculate a Total Performance Score and resulting penalty or reward, which would be set at a maximum of \$10 million each year (Coppola, 3796-3804). The Company appreciates Mr. Coppola's work, and is not opposed to exploring the implementation of a system of incentives and penalties. The proposed SIIM contains many elements that the Company could potentially support in a future PBR application (Foley, 2T 97-99).

The Company disagrees with the proposed SIIM, however, for two reasons. First, the April 24, 2023 Order in Case No. U-21400 launched the Financial Incentives and Disincentives workgroup. The initial focus includes developing appropriate metrics, and the Commission also directed the workgroup to consider future distribution grid challenges and explore rate structures and methods by which incentives and disincentives may be applied (*Id.*, p 12). Therefore, it seems premature to implement PBR before the workgroup is completed. The Company anticipates that once the workgroup completes its work, the Commission will issue guidance on what it feels is an appropriate path forward on PBR (Foley, 2T 97, 99-100, 172).

Second, the Company is concerned with some elements of the SIIM as proposed, which are in general summary: (1) insufficient time to assess because the SIIM was just recently proposed in this case, (2) basis of penalties and rewards, (3) metrics overlap, (4) metric breadth, (5) target ambiguity, and (6) complexity. Therefore, a prudent path forward is to allow the Financial Incentives and Disincentives workgroup to complete its work, potentially including exploring the proposed SIIM, and for the Commission to issue guidance on what it believes is an appropriate path forward on PBR (Foley, 2T 97, 100-102).

MNSC witness Jester suggested to link Return on Equity (ROE) to outage statistics and/or affordability (6T 3446). That would be an improper way to set the Company's ROE. As discussed above in section VII. C, some witnesses including Mr. Jester suggested that the Company's ROE should either not increase, or be reduced, but did not support their recommendations with a ROE analysis using financial market data. Thus, their unfounded and irrelevant assertions cannot support a decision and merit no serious consideration (Villadsen, 5T 3046, 3049, 3053-55, 3087-90).

For purposes of the PBR discussion here, Mr. Jester's suggestion to link ROE to outage statistics could be considered as a form of PBR because it links financial outcomes to performance

measures. Again, the prudent path forward is to allow the Financial Incentives and Disincentives workgroup to complete its work, and the Commission to issue guidance on what it believes is an appropriate path forward on PBR. Mr. Jester’s recommendation also lacks sufficient detail to even be understood, let alone properly assessed in this case. He just ambiguously links ROE to “outage statistics,” “reliability,” and “affordability,” without offering any specific proposal or detail on how those things could be linked other than vaguely suggesting that the Commission “can construct a formula.” Therefore, it is impossible to even understand or debate what he proposes, and the proposal should be disregarded (Foley, 2T 103-104).

In connection with his comments about projected test years (see section V above), ABATE witness Dauphinais suggested that an asymmetrical earnings sharing mechanism (ESM) should be imposed on the Company in this case (4T 1067-71). The suggestion should be rejected because there is not enough time to properly consider such a mechanism following ABATE’s filing of intervenor testimony. The establishment of this one-sided mechanism or any permutation that only seeks to penalize should also be rejected, and ABATE’s proposal raises legal and regulatory concerns (Crozier, 5T 216).¹²²

¹²² For example, 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.).

3. Environmental Justice in System Reliability and Distribution Planning

Consistent with the Company's 2021 Distribution Grid Plan and the Commission's March 3, 2022 order in Case No. U-21122, DTE Electric provided a geographic representation of reliability data by census tract across the Company's service territory. (See Kryscynski 3T 404 – 411) Going further, the Company overlaid reliability data with vulnerable census tracts which were determined using an 80% threshold definition for vulnerable communities using the draft MiEJScreen tool score, consistent with the U.S. Environmental Protection Agency approach (Kryscynski 3T 402). When compared to the remainder of the service territory, the 483 census tracts identified as vulnerable communities collectively had above average reliability performance in years 2020 through 2022 for SAIDI and SAIFI metrics excluding MEDs and All-Weather SAIFI compared to the systemwide levels (Kryscynski 3T 411). In addition, the vast majority of the investment in Company's proposed 2023-2024 conversion and 4.8kV hardening programs (85% and 90% respectively) is planned in vulnerable communities (Kryscynski 3T 419). DTE Electric believes that its method for evaluating reliability metrics in vulnerable communities is reasonable and prudent and demonstrates that its past and proposed investments are significantly focused on vulnerable communities.

Other intervening parties suggested alternative ways to evaluate environmental justice (EJ) related reliability. Staff witness Wang suggested utilizing a 1939 federal Home Owners Loan corporation (HOLC) map for the City of Detroit to determine if historic redlining persists in electric reliability investments. The Company does not believe that the 84 year old HOLC map provides a valid basis to consider reliability metrics in EJ communities. The MiEJScreen tool is more appropriate. The tool, which was also utilized by witness Wang in the Company's last electric rate case (U-20836), takes into account many present-day factors and was developed by state agencies

and EJ experts to determine whether a community may be considered vulnerable (3T 430). Moreover, the projects that witness Wang overlaid onto the HOLC map do not provide a full picture of the Company's investments as her timeline was too condensed and she did not consider the Company's 4.8kV hardening projects planned for 2023 on the Company's website¹²³ that are proposed for the yellow and red areas on the HOLC map. Considering past and proposed investments from 2018 to 2024 shows that DTE Electric is focusing most of its investments in areas that are the red and yellow areas on witness Wang's HOLC map (Kryscynski 3T 431-432).

Separately, CEO's witness Tan proposed that the Company should utilize a linear regression model to determine vulnerable community status (6T 3926-27). In short, the proposed regression analysis is so complex and rife with errors in statistical analysis and misinterpretation that this proposal should be rejected (Kryscynski 3T 435-439).

Last, CEO witness Periera and Staff witness Wang both suggest that the definition of vulnerable communities be reevaluated beyond the 80% to 100% threshold utilized by the Company (6T 3895-3896). The Company disagrees with these proposals to readjust the vulnerable community threshold. The Company is early in its EJ journey and is identifying those customers who are the most vulnerable with poor reliability and developing plans to improve their reliability. Constantly adjusting those targets will slow the Company's efforts in this space.

4. Contributions in Aid of Construction (CIAC) and Standard Allowance Table

The Commission previously agreed with this ALJ to continue discussion of CIAC recommendations through the CIAC workgroup (November 18, 2022 Order in Case No. U-20836, pp. 475-76).

¹²³ [Electric Reliability Improvements Map \(arcgis.com\)](https://arcgis.com)

MNSC witness Ozar presented CIAC testimony focused on per-foot costs in Section C6 of the Company's rate book, which are chargeable to individual customers based on work performed by the Company for the customer. He essentially asserted that it would be inconsistent to update the Standard Allowance table without also updating the per-foot costs, and recommended that the Commission refuse to update the Standard Allowance table until the Company has updated the per-foot costs (Ozar, 6T 3574-78).

The Company disagrees because the per-foot costs are unrelated to the Standard Allowance table. Mr. Ozar conflated two different things. There are two distinct elements when determining a customer's actual CIAC: (1) the cost of the work, however determined, and (2) any allowances provided to the customer based on the margin contribution of the new or increased load. The per-foot costs are part of (1) because they are a construction cost. The Standard Allowance table is part of (2) because it is based on the margin contribution of a customer on a given rate schedule and greater than 1000 kW of load. It would be inappropriate to hold the table in limbo, and unduly impact the Company's largest customers, contingent on the outcome of an unrelated matter. The Company also believes that the per-foot costs in its tariff remain appropriate.¹²⁴ Therefore, the Commission should approve the updates to the Standard Allowance table consistent with prior practice and utilizing the ordered rates resulting from this case (Robinson, 5T 2723; Willis, 5T 3229-31).

¹²⁴ No contrary evidence has been presented, so the Company is unable to respond in further detail. In *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), our Supreme Court explained that "[t]he party alleging a fact to be true should suffer the consequences of a failure to prove the truth of that allegation." Thus, unproven allegations cannot stand in the place of evidence. Things not proven must be taken as not existing, since a decision cannot be based upon conjecture. *Star Steel v USF&G*, 186 Mich App 475, 481; 465 NW2d 17 (1990); *see also, Skinner v Square D Co*, 445 Mich 153; 516 NW2d 475 (1994). There is no requirement to even respond to unfounded allegations. *Lendberg v Brotherton Iron Mining Co*, 75 Mich 84, 89; 42 NW 675 (1889).

5. Time-of-Use (TOU) Commercial Secondary and Primary Rates

MEIBC/IEI/United witness Barnes proposed that the Commission direct the Company to replicate the design of Rate Schedule D1.11 (Residential TOU) for commercial secondary and primary customers, suggesting that there are no significant issues because D1.11 has already been approved based on a considerable record of evidence (Barnes, 6T 4237, 4247-50). The Company disagrees because the “considerable record of evidence” concerned residential rate design. There is no record of evidence regarding D1.11 and commercial or primary customers. Residential customers also have different characteristics than commercial and primary customers. For example, witness Barnes suggested a pricing window for every customer group based on a rate design reflecting residential usage patterns. Time-of-use rates for commercial secondary and primary customers must be addressed on their merits (whatever the merits might be, and for each customer group separately, using the specific and relevant data for each proposed application), and cannot simply be copied from residential rates as Mr. Barnes proposed. Moreover, due to the inconsistencies in Mr. Barnes’ testimony, the Company is unable to discern what he would consider to be an acceptable commercial secondary and primary time-of-use rate design beyond simply replicating the D1.11 residential rate design. Therefore, the proposal should be summarily rejected (Willis, 5T 3235-38, 3241-42).

Mr. Barnes also suggested that demand rates are inappropriate (Barnes, 6T 4238). To the contrary, large customer rate design across the country appropriately uses demand rates to charge customers based on their peak usage, which in the case of primary customers, is substantial. Allowing low load factor primary voltage customers to choose a time-of-use rate would shift costs to other customers as they would provide a decreasing share of their cost to serve. Thus, primary voltage demand charges remain the most appropriate way to price electric service for large customers (Willis, 5T 3238-39). Mr. Barnes further suggested that customers should have options,

but optionality cannot exist apart from cost alignment. There also already are options in commercial pricing (D3, D4, D1.8, and D3.3) and primary pricing (D11, D8, and Rider 10) (Willis, 5T 3239-40).

Mr. Barnes' proposal that the Company file tariffs "within 30 days" of the Commission's order in this case (6T 4250) is also unreasonable. Even if the proposed ratemaking approach was prudent (which it is not, as outlined above), the Company would be unable to complete IT development, testing, and implementation of new rates in that period, and related costs have not been contemplated or proposed (Willis, 5T 3241-42).

6. Generation Meters

MEIBC/IEI/United witness Hoyle proposed that the Commission "grant waivers of the requirement in Michigan's interconnection regulations that requires the installation of generation meters on distributed generation ('DG') facilities larger than 20 kW, and that the Commission grant any other relief necessary to ensure that a requirement for DG customers to install generation meters does not continue to be an unreasonable impediment to DG installations" (Hoyle, 6T 4210).

The Company disagrees because the proposal is contrary to MCL 460.1177(1), which relevantly provides: "For a customer with a generation system capable of generating more than 20 kilowatts, the utility **shall install and utilize a generation meter** and a meter or meters capable of measuring the flow of energy in both directions" (Emphasis added). It is axiomatic that statutory language must be applied as written.¹²⁵ The statute is clear, and repeatedly uses the term "shall,"

¹²⁵ *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("We presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"). *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); *Amb's v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003).

which denotes a mandatory duty imposed by the Legislature, and excludes the idea of administrative discretion.¹²⁶ Therefore, the proposal should be rejected.

For completeness, the Company further notes that Mr. Hoyle further asserted that “DTE has no system safety or reliability use for generation meters” because any necessary data is allegedly available from meters that measure power inflow, and the aggregate capacity of QFs over 20kWac is allegedly inconsequential for system reliability purposes (6T 4230). To the contrary, bidirectional meters measure at a different electrical location than generation meters, and are unable to separate out actual load from actual generation unless the customer is 100% exporting or 100% importing power, which is an unlikely occurrence for a customer with both load and generation. Generation metering also provides information about gross load, voltage, power quality, and status. This information is critical to the safe operation of the electrical system. For example, knowledge of gross load is critical to safely performing switching when there has been an interruption. Generation metering is also needed for generation system capacity planning. QFs greater than 20kWac are material to system reliability and planning at the localized circuit level (Robinson, 5T 2708-2709).

The Company acknowledges that generation meters involve costs, and continues to work with QFs to manage costs; however, data about the operating status of interconnected generation is not an area where an accommodation can be made without the safety and reliability impacts outlined above. The proposed waiver focuses on reducing interconnection customer costs, but it would increase rates for others, and is inconsistent with the principle of allocating costs to cost causers. Therefore, the recommendation should be rejected (Robinson, 5T 2710).

¹²⁶ *Macomb Co Rd Comm'n v Fisher*, 170 Mich App 697, 700; 428 NW2d 744 (1988); *Southfield Twp v Drainage Bd*, 357 Mich 59, 76-77; 97 NW2d 281 (1959) (“the word ‘shall’ is mandatory and imperative and, when used in a command to a public official, it excludes the idea of discretion”).

Mr. Hoyle also inaccurately characterized Rider 3 metering requirements (6T 4223). Initial Rider 3 contract capacity determination is unrelated to generation meters, and accurate billing on Rider 3 would not be possible without a generation meter (Willis, 5T 3243-44).

MEIBC/IEI/United witness Sherman asserted that “it seems logical to me that generation meters are likely unnecessary and duplicative” while offering no evidentiary support for the assertion (6T 4182). Again, the suggestion does not merit consideration because MCL 460.1177(1) plainly says “For a customer with a generation system capable of generating more than 20 kilowatts, the utility **shall install and utilize a generation meter and a meter or meters capable of measuring the flow of energy in both directions**” (Emphasis added). Also for completeness and as indicated above, bidirectional meters do not perform the same functions as a generation meter, and generation meters provide valuable data. The costs to install Category 2 generation metering (20kWac-150kWac) are also necessary and reasonable, so the Commission should reject the suggestion to remove the requirements for Category 2 generation meters to ensure that costs are not transferred from interconnection projects to other customers (Robinson, 5T 2708-13).

MEIBC/IEI/United witness Sherman further stated: “My understanding is that the Company’s Green Book has not historically been subject to specific Commission review and approval. However, I see no reason why it should be beyond the reach of the Commission’s regulatory authority” (6T 4183-84).¹²⁷ The Company disagrees with the suggestion that the Commission should require oversight of the Green Book. Oversight is unnecessary and witness

¹²⁷ The DTE “Green Book” is the electrical installation guide that the Company provides to developers, and which is available on DTE Energy’s website. It outlines the requirements of the installation of equipment related to metering and/or that could impact DTE personnel working on the electrical system. It is a wide-ranging document encompassing all points of interconnection with the electrical system, not just generation interconnection metering. It provides the technical specifications necessary to ensure no connection or customer equipment impacts the grid or other customers (Robinson, 5T 2714-15).

Sherman provides no evidence that such oversight would benefit the Company or customers (Robinson, 5T 2715).

7. Community Solar and MIGreenPower Community Impact Pilot

The Commission previously ordered the Company to file a straw proposal for community solar in its Voluntary Green Pricing (VGP) docket, Case No. U-21172 (November 18, 2022 Order in Case No. U-20836, p 456). The Company did so. DAAO witness Koeppel apparently dislikes that proposal, and asserts an unsupported list of demands for a different proposal, vaguely incorporating his own testimony from Case No. U-21172 and witness Donovan’s testimony from Case No. U-20836 (Koeppel, 6T 4051-53).

The Company disagrees because it properly filed its proposal in Case No. U-21193 in accordance with the U-20836 Order. It is improper for DAAO to attempt to “pancake” that case with this case. Also, “the time constraints and voluminous issues of a general rate case do not allow for the full development of a community solar program” as this ALJ previously observed (U-20836 PFD, p 346). The Commission reasonably determined that community solar is best addressed in the VGP case, which remains pending. It would be procedurally and legally inappropriate to attempt to litigate that case here, or propose yet another community solar program while the first proposal is still being considered. Therefore, DAAO’s proposal should be rejected (Crozier, 5T 2222-24).

There is similarly no merit in DAAO witness Koeppel’s proposal regarding the Company’s MIGreenPower Community Impact Pilot, that “[s]hould the program fail due to the design deficiencies highlighted by Soulardarity in response to the settlement agreement in #20713, the Commission should order DTE to produce a detailed report on the IT expenditures and how they may be repurposed to serve to establish subscription management for a true community solar program. Failing that, those IT expenditures should be deemed non-recoverable” (Koeppel, 6T

4053). The Company incurred the IT costs for a pilot that was included in the Settlement Agreement that the Commission approved in Case Nos. U-20713 and U-20851. DTE Electric maintains that the expenditures are reasonable and prudent and necessary to implement the settlement. DAAO made no showing otherwise, but apparently just disagrees with the settlement. Therefore, DAAO's disallowance proposal lacks any valid basis. DAAO's proposal that the Company write a "detailed report" on how IT costs could be repurposed for a different program, based on vague speculation that the still-pending program might somehow fail, is unwarranted and would be administratively wasteful. Therefore, DAAO's proposals should be rejected (Crozier, 5T 2224-26).

8. MISS DIG

Staff made four recommendations regarding the MISS DIG process (Becker, 7T 4351-52). The Company generally agrees, except regarding the recommendation that the Company begin to track expenditures for damage caused by the Company to its own facilities. The Company does not currently track the expenditures due to the low number of instances, and does not have a way to separate them historically. Tracking the expenditures would require new processes and procedures to be implemented, along with additional training for field personnel. Due to the low number of instances, the additional costs and training are not justified (Hill, 5T 2831-32).

XI. REQUEST FOR RELIEF

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

A. Granting DTE Electric's request for final rate relief, as further supported and explained in its Application, testimony, exhibits, and this Initial Brief (including Attachments A and B) approving rates that will recover the Company's revenue deficiency of approximately \$583

million (\$586 million without approval of the IRM), based on a December 1, 2023 through November 30, 2024 projected test year;

B. Approving an annual revenue increase effective as soon as possible in the projected test year;

C Approving new rates effective as early as December 10, 2023 in the manner described in the Company's Application, testimony, exhibits, 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 Company's proposed IRM;

J. Approving all proposed pilot programs as requested by the Company;

K. Approving all proposed regulatory accounting treatments as requested by the Company;

L. Approving the capacity charge calculated by the Company, which is based on the methodology utilized in Case No. U-20836, and approving the capacity-related costs supported by the Company in this proceeding;

M. Approving the remainder of DTE Electric’s proposals and requested relief as set forth in the Company’s Application, testimony, exhibits 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

By: _____
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Dated: August 15, 2023

DTE Electric Company
Computation of Revenue Deficiency
Projected 12 Month Period Ending November 30, 2024
(\$000)

MPSC Case No. U-21297
Initial Brief
Attachment A
Page 1 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	Rate Base (1)	\$ 22,611,230	\$ (266,756)	\$ 22,344,475	\$ 22,274,637	\$ 69,837
2	Adjusted Net Operating Income (2)	836,780	11,076	847,856	952,529	(104,672)
3	Rate of Return (3)	5.6986%	0.0000%	5.6986%	5.5217%	0.1769%
4	Income Requirements	1,288,524	(15,202)	1,273,322	1,229,929	43,393
5	Income Deficiency (Sufficiency)	451,744	(26,278)	425,466	277,400	148,065
6	Revenue Conversion Factor (4)	1.3496	-	1.3496	1.3496	-
7	Rev Deficiency / (Sufficiency)	\$ 609,689	\$ (35,466)	\$ 574,223	\$ 374,389	\$ 199,834
8	Tree Trim Surge (5)	8,847	0	8,847	8,847	0
9	Revenue Deficiency (Sufficiency)	\$ 618,536	\$ (35,466)	\$ 583,070	\$ 383,236	\$ 199,834

Sources

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

DTE Electric Company
Rate Base - Average Net Plant
For the 12 Month Average Period Ending 11/30/2024
(\$000)

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	\$ 26,771,019	\$ (261,048) (1)	\$ 26,509,971	\$ 26,510,902	\$ (931)
2	Plant Held for Future Use	76,508		76,508	76,508	-
3	Construction Work in Progress	2,149,642		2,149,642	2,060,036	89,606
4	Total Utility Plant	28,997,168	(261,048)	28,736,120	28,647,446	88,675
5						
6	Less: Depreciation Reserve	7,845,749	(3,230) (2)	7,842,519	7,822,124	20,395
7						
8	Net Utility Plant	21,151,419	(257,818)	20,893,601	20,825,322	68,279
9						
10	Net Capital Lease Property	11,636		11,636	11,636	-
11	Net Nuclear Fuel Property	201,880		201,880	201,880	-
12						
13	Total Utility Property and Plant	21,364,936	(257,818)	21,107,118	21,038,838	68,279
14						
15	Less: Capital Lease Obligations	13,486		13,486	13,486	-
16						
17	Net Plant	21,351,450	(257,818)	21,093,632	21,025,353	68,279
18						
19	Allowance for Working Capital	1,259,780	(8,938) (3)	1,250,843	1,249,285	1,558
20						
21						
22	Rate Base	\$ 22,611,230	\$ (266,756)	\$ 22,344,475	\$ 22,274,637	\$ 69,837

(1) (2) Capital adjustments to Plant and Depreciation Reserve:

	Net Cap Ex	Plant Adj. (1)	Accum. Depr. (2)	
EV Home Charger/Rider 22	(4,200)	(2,100)	(43)	4T 801
PrePay II	(2,640)	(1,320)	(132)	5T 1742-43
Nuclear Generator Project	(286,824)	(257,628)	(3,055)	STDE-21.1 / DTE Brief section V(B)(3)
	\$ (293,664)	\$ (261,048)	\$ (3,230)	

(3) Working Capital:
Change to 13-month average
Non-utility A/R

(1,680)	7T 4448
(7,258)	7T 4448
\$ (8,938)	

DTE Electric Company
Adjusted Net Operating Income
Projected 12 Month Period Ending November 30, 2024
(\$000)

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	\$ 5,112,874		\$ 5,112,874	\$ 5,115,278	\$ 2,404
3	Other Operating Revenue	-		-	-	-
4	Fuel and Purchased Power	1,361,901		1,361,901	1,361,901	-
5	Net Margin	3,750,973	-	3,750,973	3,753,378	2,404
6						
7	Operating Expenses					
8	Operations and Maintenance Expenses	1,302,355	(13,403) (1)	1,288,952	1,169,561	(132,794)
9	Depreciation and Amortizations	1,168,921	(6,459) (2)	1,162,462	1,145,942	(22,979)
10	Property Taxes	320,250		320,250	320,250	-
11	Other Taxes	50,173		50,173	50,173	-
12	Total Operating Expenses	2,841,699	(19,862)	2,821,837	2,685,926	(155,773)
13						
14	Operating Income	909,274	19,862	929,136	1,067,452	158,178
15						
16	Other Operating Income Adjustments					
17	Allow. For Funds Used During Constr	43,035	(3,357) (3)	39,678	43,035	(0)
18	Amortization of Loss on Reacquired Debt	(2,980)		(2,980)	(2,980)	-
19	Other Income	(1,277)		(1,277)	(1,277)	-
20	Total Operating Income Adjustments	38,778	(3,357)	35,421	38,778	(0)
21						
22	PreTax Adjusted Net Operating Income	\$ 948,052	\$ 16,505	\$ 964,557	\$ 1,106,230	\$ 158,177
23						
24	State Income Taxes	64,503	1,233	65,737	74,674	10,171
25	Federal Income Taxes	46,769	4,195	50,964	79,027	32,258
26						
27	Net Operating Income	\$ 836,780	\$ 11,076	\$ 847,856	\$ 952,529	\$ 115,749

(1) O&M

Tree Trim O&M Surge Savings	\$ (6,300)	5T 2162-63
Uncollectibles Expense	(6,759)	DTE Brief section VII(C)(7)
Corporate Membership Fees	(20)	7T 4580
Regional Relations Labor & Other Expenses	(324)	DTE Brief section VII(C)
	\$ (13,403)	

(2) Depreciation and Amortization

EV Home Charger/Rider 22	\$ (86)	4T 801
PrePay II	(264)	5T 1742-43
Nuclear Generator Project	(6,109)	STDE-21.1 / DTE Brief section V(B)(3)
	\$ (6,459)	

(3) AFUDC

Nuclear Generator Project	3,357	STDE-21.1 / DTE Brief section V(B)(3)
	\$ 3,357	

DTE Electric Company
Rate of Return Summary
Projected 12 Month Period Ending November 30, 2024
Based on Average Rate Base
(\$000)

MPSC Case No. U-21297
Initial Brief
Attachment A
Page 4 of 4

Line No.	(a) Description	(b) Amounts (\$000)	Capital Structure		(e) Cost Rate %	Weighted Costs				
			(c) Percent Permanent Capital	(d) Percent of Total Capital		(f) Permanent Capital	(g) Total Cost %	(h) Conversion Factor	(i) Pre-Tax Return	
U-21297 Filed Position (Test Period Average Basis)										
1	Long-Term Debt	\$ 8,876,109	50.00%	39.26%	4.06%	2.028%	1.59%	100.000%	1.592%	
2	Preferred Stock	0		0.00%	0.00%	0.000%	0.00%	134.964%	0.000%	
3	Common Shareholders' Equity	8,876,081	50.00%	39.26%	10.25%	5.125%	4.02%	134.964%	5.431%	
4	Total	<u>17,752,190</u>	<u>100.00%</u>			<u>7.153%</u>				
5										
6	Short-Term Debt	330,941		1.46%	4.98%		0.07%	100.000%	0.073%	
7										
8										
9										
10	Job Development - ITC - Debt	15,986		0.07%	4.06%		0.00%	100.000%	0.003%	
11	Job Development - ITC Equity	15,986		0.07%	10.25%		0.01%	134.964%	0.010%	
12	Total Job Development - ITC	<u>31,973</u>								
13										
14	Deferred Income Taxes (Net)	<u>4,496,126</u>		<u>19.88%</u>	0.00%		<u>0.00%</u>		<u>0.000%</u>	
15										
16	Total	<u>22,611,230</u>		<u>100.00%</u>			<u>5.70%</u>		<u>7.108%</u>	
U-21297 Initial Brief Position (Test Period Average Basis)										
17	Long-Term Debt	\$ 8,876,109	50.00%	39.26%	4.06%	2.028%	1.59%	100.000%	1.592%	
18	Preferred Stock	0			0.00%	0.000%	0.00%	134.964%	0.000%	
19	Common Shareholders' Equity	8,876,081	50.00%	39.26%	10.25%	5.125%	4.02%	134.964%	5.431%	
20	Total	<u>17,752,190</u>	<u>100.00%</u>			<u>7.153%</u>				
21										
22	Short-Term Debt	330,941		1.46%	4.98%		0.07%	100.000%	0.073%	
23										
24										
25										
26	Job Development - ITC - Debt	15,986		0.07%	4.06%		0.00%	100.000%	0.003%	
27	Job Development - ITC Equity	15,986		0.07%	10.25%		0.01%	134.964%	0.010%	
28	Total Job Development - ITC	<u>31,973</u>								
29										
30	Deferred Income Taxes (Net)	<u>4,496,126</u>		<u>19.88%</u>	0.00%		<u>0.00%</u>		<u>0.000%</u>	
31										
32	Total	<u>22,611,230</u>		<u>100.00%</u>			<u>5.70%</u>		<u>7.108%</u>	

DTE Electric Company
Rate of Return Summary
Projected 12 Month Period Ending November 30, 2024
(\$000)

MPSC Case No. U-21297
Initial Brief
Attachment B

(a)	(b)	(c)
Line No.	Description	Source
1	Company's Filed Position	Exhibit A-11 Sch A-1
2		
3	<u>Adjustments to Revenue Deficiency:</u>	
4		
5		Rate Base
6	Rate Base (1)	<u>Changes</u>
7	EV Home Charger/Rider 22	(2) Attachment A page 2 (2,057) (146)
8	PrePay II	(2) Attachment A page 2 (1,188) (84)
9	Nuclear Generator Project	(3) Attachment A page 2 (254,573) (18,095)
10	Change to 13-month average	(2) Attachment A page 2 (1,680) (119)
11	Non-utility A/R	(3) Attachment A page 2 (7,258) (516)
12		
13		<u>(266,756)</u>
14	Operations and Maintenance Expenses	
15	Tree Trim O&M Surge Savings	(3) Attachment A page 3 (6,300)
16	Uncollectibles Expense	(2) Attachment A page 3 (6,759)
17	Corporate Membership Fees	(3) Attachment A page 3 (20)
18	Regional Relations Labor & Other Expenses	(3) Attachment A page 3 (324)
19		
20		
21	Depreciation and Amortization	
22	Depreciation Expense, Increase/(Decrease)	Attachment A page 3 (6,459)
23		
24	AFUDC	
25	AFUDC, Increase/(Decrease)	Attachment A page 3 3,357
26		
27	Total Adjustments to Company's Initial Revenue Deficiency	Line 7 through Line 25 \$ (35,466)
28		
29	Company's Brief Position	Line 1 + Line 27 <u>\$ 583,070</u>

(1) Rate Base Change multiplied by pre-tax return 7.11% (Attachment A page 4)
(2) Amount withdrawn or reconsidered due to proposed disallowance
(3) Amount withdrawn due to error

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21297

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on August 15, 2023, 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

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