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January 14, 2020

Ms. 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-20561

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/lah
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-20561
(Paperless e-file)

DTE ELECTRIC COMPANY'S INITIAL BRIEF

Dated: January 14, 2020

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I. INTRODUCTION

This case began on July 8, 2019, when DTE Electric Company (DTE Electric or the Company) filed its Application and supporting direct testimony and exhibits, requesting a jurisdictional rate increase of approximately \$351 million, and other forms of regulatory relief. The projected revenue deficiency spans the projected test year of May 1, 2020 through April 30, 2021 (9T 3414, 3419; Exhibit A-11, Schedule A1).

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 the Company's customers. After reviewing Staff's and other intervenors' positions, DTE Electric is reducing its projected revenue deficiency to \$343.0 million to account for: a) plant reductions due to capital cost eliminations related to contingency of HQ Energy Center (\$3.2 million) and Blue Water Energy Center (\$14.6 million) and the related depreciation impacts; b) working capital reductions due to the correction of a \$2 million error in the accounts payable balance and an elimination of \$68 million included in the accounts receivable balance in error; c) reduction of Marketing operation and maintenance (O&M) expense of \$1 million to reflect only amortization associated with audited Electric Vehicle (EV) costs; and d) reduction in Administrative and General O&M to reflect corporate memberships of \$285,000 that should have been excluded. (See Company's Attachments A and B included with this Brief). Therefore, DTE Electric requests that the Commission authorize an adjustment of rates to provide an additional \$343.0 million annually.

II. HISTORY OF PROCEEDINGS

DTE Electric Company is presently serving its jurisdictional electric customers under rate schedules and charges approved by this Commission in its Orders dated May 2, 2019 and July 2, 2019 in Case No. U-20162, and pursuant to various Commission-approved special contracts.

In accordance with MCL 460.6a(1), DTE Electric filed its Filing Announcement indicating the Company's intent to file an application for authority to increase its rates on June 6, 2019. The Company's Rate Case Summary was filed on July 3, 2019, and the Application was filed on July 8, 2019. On July 31, 2019, a pre-hearing conference was held and intervention was granted to the Michigan Attorney General (AG); the Association of Businesses Advocating Tariff Equity (ABATE); Citizens Utility Board (CUB¹); Energy Michigan, Inc. (Energy Michigan or EM); Foundry Association of Michigan (FAM); Michigan Cable Telecommunications Association (MCTA); Utility Workers Union of America Local 223 (UWUA or UWL 223); Great Lakes Renewable Energy Association (GLREA); Residential Customer Group (RCG); Wal-Mart, Inc. (Wal-Mar); the Kroger Company (Kroger); the Michigan Environmental Council (MEC), Natural Resource Defense Council (NRDC) the Sierra Club (SC) and the Citizens Utility Board of Michigan (CUB) (collectively MEC/NRDC/SC/CUB); ChargePoint, Inc. (ChargePoint); the Environmental Law & Policy Center, Ecology Center, Solar Energy Industries Association, and Vote Solar (collectively ELPC); Soulardarity; Michigan Cable Telecommunications Association (MCTA); Central Transport, LLC; Central Transport, Inc.; Detroit International Bridge Company; and Universal Truckload Services, Inc. (1T 10).

¹ At times CUB joined MEC/NRDC/SC on specific issues.

Along with its Application, DTE Electric provided direct testimony and exhibits of 27 witnesses in support of its request for a rate increase and other regulatory relief. Robert A. Bellini is the Manager of Community Lighting (qualifications and direct testimony at 9T 3475-3505); Timothy A. Bloch is a Principal Financial Analyst in DTE Energy Corporate Services LLC's Regulatory Affairs organization (qualifications and direct testimony at 8T 2277-90); Alex M. Brasil is a Senior Rates Analyst – Load Research (qualifications and direct testimony at 8T 2317-28); Marco A. Bruzzano is Vice President, Distribution Operations at DTE Energy Corporate Services LLC's (qualifications and direct testimony at 4T 116-239); 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 797-818); Henry N. Campbell is the Director of the Customer Care Organization at DTE Energy Corporate Services LLC (qualifications and direct testimony at 8T 2544-66); Rodrigo Cejas Goyanes is a Strategy and Project Specialist in DTE Electric's Demand Response and Energy Waste Reduction Strategy department (qualifications and direct testimony at 9T 3507-38); Eric W. Clinton is a Manager in DTE Electric's Electric Regulated Marketing Organization (qualifications and direct testimony 6T 997-1041); Michael S. Cooper is DTE Energy Corporate Services LLC's Director of Compensation, Benefits & Wellness (qualifications and direct testimony at 5T 887-947); Adella F. Crozier is the Director of Regulatory Affairs for DTE Energy Corporate Services LLC (qualifications and direct testimony at 4T 456-85); Jeffrey C. Davis is DTE Electric's Manager of Nuclear Strategy and Business Support (qualifications and direct testimony at 9T 3427-62); Phillip W. Dennis is a Manager, Regulatory Economics (qualifications and direct testimony at 7T 2117-27); Daniel J. Griffin was at the time of filing direct testimony the Director – Information Officer in the Information Technology Services (ITS) organization of DTE Energy Corporate Services LLC (qualifications and direct testimony at

8T 2354-2460),² Kelly A. Holmes is a Principal Financial Analyst – Regulatory Economics in DTE Energy Corporate Services LLC’s Regulatory Affairs organization (qualifications and direct testimony at 8T 2245-59); Tamara D. Johnson is DTE Energy’s Director, Revenue Management and Protection (RM&P) (qualifications and direct testimony at 6T 1135-48); Thomas W. Lacey is a Principal Financial Analyst in the Revenue Requirements Department of DTE Energy Corporate Services LLC’s Regulatory Affairs organization (qualifications and direct testimony at 7T 2009-32); Joyce E. Leslie is DTE Electric’s Director – Business Planning & Development (qualifications and direct testimony at 5T 755-69); Markus B. Leuker is DTE Electric’s Manager of Corporate Energy Forecasting (qualifications and direct testimony at 4T 397-421); David C. Milo is a Fuel Resource Specialist in the Operations and Logistics section of the Company’s Fuel Supply Department (qualifications and direct testimony at 9T 3919-28); Justin L. Morren is DTE Electric’s Plant Director of Fossil Generation (qualifications and direct testimony at 5T 567-634); Heather D. Rivard is DTE Electric’s Senior Vice President of Electric Distribution (qualifications and direct testimony at 9T 3577-3628); Jaqueline L. Robinson is the Director of Operational Technology in DTE Electric’s Electric Distribution Operations organization (qualifications and direct testimony at 9T 2609-26); Edward J. Solomon is the Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy and its subsidiaries, including DTE Electric (qualifications and direct testimony at 6T 1447-63); Margaret A. Suchta is a Consultant in the Revenue Requirements group of DTE Energy Corporate Services LLC’s Regulatory Affairs organization (qualifications and direct testimony at 9T 3404-20); Theresa M. Uzenski is the Manager of Regulatory Accounting for DTE Energy Corporate Services LLC (qualifications and direct testimony at 6T 1478-1557); Dr. Bente Villadsen is a Principal of The Brattle Group, which

² In September of 2019, Mr. Griffin became DTE Electric’s Director of Distribution Operations (8T 2484-85).

is an economic, environmental and management consulting firm (qualifications and direct testimony at 6T 1202-1306); and Sherri L. Wisniewski is DTE Energy's Director of Tax Operations (qualifications and direct testimony at 9T 3559-75).

On November 6, 2019, the Commission Staff and Intervenors filed their testimony and exhibits. Staff provided the testimony of Brad B. Banks (9T 3189-96), Jonathan J. DeCooman (9T 3198-3205), Michelle L. Edelyn (9T 3207-13), Nicholas M. Evans (9T 3219-33), Jay S. Gerken (9T 3235-41), Daniel J. Gottschalk (9T 3243-51), David W. Isakson (9T 3110-38), Cody S. Matthews (9T 3262-69), Theresa McMillan-Sepkoski (9T 3271-84), Kirk D. Megginson (9T 3286-3313), Robert F. Nichols II (9T 3325-33), Jing Shi (9T 3343-51), Joseph E. Ufolla (9T 3314-22), Joy H. Wang (9T 3353-79), Brian Welke (9T 3334-41), and Timothy G. Witt (9T 3214-17).

ABATE provided the testimony of Amanda M. Alderson (7T 1799-1821), James R. Dauphinais (7T 1634-63), Christopher C. Walters (7T 1822-1902), and Jessica A. York (7T 1919-48). The AG provided the testimony of Sebastian Coppola (9T 2954-3096) and David E. Dismukes (9T 2829-73), and with MEC/NRDC/SC/CUB, Roger D. Colton (9T 3639-3733). FAM provided the testimony of Alexander Zakem (9T 2754-70). GLREA provided the testimony of Robert Rafson (9T 2776-88), and John Richter (9T 2789-99). Kroger provided the testimony of Justin Bieber (8T 2154-68). UWL 223 provided the testimony of Jonathan Hardon (9T 2741-46), and Michael Smith (9T 2748-52). ELPC provided the testimony of William D. Kenworthy (9T 2722-38) and Christopher Villarreal (9T 2683-2720). MEC/NRDC/SC/CUB provided the testimony of Karl G. Boothman (9T 3862-81), Richard Bunch (9T 3900-13), David L. Gard (9T 3883-98), Douglas B. Jester (9T 3795-3860), and Steve Letendre (9T 3736-93). RCG provided the testimony of Geoffrey C. Crandall (9T 2809-25). Soulardarity provided the testimony of Jackson Koepfel (6T 1396-1444). Wal-Mart provided the testimony of Steve W. Chriss (9T 3658-80).

On December 2, 2019, DTE Electric filed the rebuttal testimony and exhibits of witnesses Bloch (8T 2291-99), Brasil (8T 2329-34), Bruzzano (4T 240-86), Burgdorf (5T 819-26), Cejas Goyanes (9T 3539-57), Clinton (6T 1042-62), Cooper (5T 948-64), Crozier (4T 486-508), Davis (9T 3463-72), Dennis (7T 2128-36), Griffin (8T 2461-83), Holmes (8T 2260-64), Johnson (6T 1149-62), Lacey (7T 2033-48), Leslie (5T 770-80, stricken in part at 4T 105-106),³ Leuker (4T 422-30), Morren (5T 635-61), Rivard (9T 3629-36), Robinson (9T 2627-36), Solomon (6T 1464-68), Suchta (9T 3421-24), Uzenski (6T 1558-76), and Villadsen (6T 1307-48).

ABATE filed the rebuttal testimony of witnesses Dauphinais (7T 1664-1711), and Walters (7T 1903-18). The AG filed the rebuttal testimony of witnesses Coppola (9T 3097-3105) and Dismukes (9T 2938-52; stricken in part at 4T 82). GLREA filed the rebuttal testimony of witness Richter (9T 2800-2806; stricken in its entirety at 4T 82). Kroger filed the rebuttal testimony of witness Bieber (8T 2169-2200). Staff filed the rebuttal testimony of witnesses Gottschalk (9T 3252-60), Isakson (9T 3139-56), Kevin S. Krause (9T 3381-91), and Nicholas M. Revere (9T 3393-3400).

³ DTE Electric incorporates its prior filings and arguments, and maintains all of its rights regarding the striking of Ms. Leslie's testimony.

Cross-examination and binding-in of testimony was held on December 13 and 16-20, 2019. Subsequent to the close of the record on December 20, 2019 the Administrative Law Judge (ALJ) provided direction regarding her briefing preferences by e-mail.⁴

III. SUMMARY OF MAJOR ISSUES

DTE Electric initially requested that the Commission authorize an adjustment of rates to provide an additional \$351 million annually, based on \$18,251.3 million in rate base and \$1,353.4 million in O&M expense. As discussed in section I above, DTE Electric has adjusted its request to \$343 million. The revenue deficiency is largely driven by the revenue requirement associated with increased investments in plant, associated depreciation and property tax increases, and increased O&M, primarily driven by inflation. The Company is seeking a return on equity (ROE) of 10.5%,

⁴ “Dear Counsel:

In order to more clearly identify the issues in dispute in this case and to assist me in resolving those issues, I am requesting that you do the following in preparing your briefs and reply briefs:

1. Issue Identification

Please clearly state each issue you are addressing, and the corresponding relief you are seeking from the Commission. If you change your position on an issue after your initial brief is filed, please indicate that change clearly in your reply brief, not in a footnote.

2. Whole Record Discussion

Please identify the relevant portions of the record on each issue you address, and address the record on that issue comprehensively including any rebuttal testimony and cross-examination in your initial briefs.

3. Prior Commission Orders

For each issue you address, please identify relevant portions of the Commission’s most recent rate case order for DTE Electric, Case No. U-20162, and discuss as appropriate.

4. Citations and Quotations

When citing testimony in the evidentiary record in this case, please identify the witness as well as the transcript volume and page. When citing an exhibit, please identify the page(s) as well the exhibit number if the exhibit has more than one page.

Lengthy quotations and near-verbatim recitations of testimony are discouraged—I will read the portions of the record you rely on, and I prefer your summaries, analysis, and argument.

5. Reply briefs

In your reply briefs, please do not repeat the text of the arguments you made in your initial briefs. You may incorporate your prior arguments by reference, and include the page numbers from your initial briefs. Make clear what contentions you are replying to, and as noted above, if you have changed your position, state that clearly at the outset of your discussion...” (January 2, 2020 E-mail from Administrative Law Judge to Parties)

and uses an inflation factor of 2.8% for 2019, 2.9% for 2020, and 1.0% for January 1 through April 30, 2021.

IV. 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.*

The Michigan Constitution requires the Commission’s findings to “be supported by competent, material and substantial evidence on the whole record.” Const 1963, Art 6, § 28. 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). 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). “[S]ubstantial evidence is ‘more than a mere scintilla’ but less than a ‘preponderance’ of the evidence.” *Huron Behavioral Health v Dep’t of Behavioral Health*, 293 Mich App 491, 497; 813 NW2d 763 (2011). Thus, the applicable standard of proof for purposes of determining whether the Company’s proposals or recommendations are reasonable and prudent is the “substantial evidence” standard, which is a lighter standard than even the “preponderance of the evidence” standard, which itself is a lighter standard than the “beyond a reasonable doubt” standard that is only applicable to criminal proceedings.⁵ For the reasons

⁵ *Thangavelu v Dep’t of Licensing & Regulation*, 149 Mich App 546, 554-555; 386 NW2d 584 (1986).

discussed below, DTE Electric's proposals and recommendations in this case more than satisfy the "substantial evidence" standard as demonstrated by the record.

The Administrative Procedures Act (APA) also 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. *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002).

In *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), the Michigan 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).

Finally, 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) (reversed Commission finding that the Company had made misrepresentation because decision was not based on sufficient record evidences, but rather was based on speculation); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that

agency's decision was not supported by evidence that a reasonable person would consider adequate).

B. Rate Setting Legal Requirements

All Commission decisions must be authorized by law, and the Commission's findings of fact must be supported by competent, material and substantial evidence, in the record. Const 1963, Art 6, § 28; MCL 24.285.

Utilities are also provided 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.⁶

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 *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'

⁶ 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).

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.⁷ The Commission has an obligation to facilitate DTE Electric’s financial health for the benefit of its electric customers and shareholders. *See, by way of example and not limitation*, MCL 460.6j(1); MCL 460.10(2)(e); *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).

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

⁷ 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).

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.

In Michigan, our Supreme Court announced the retroactive ratemaking prohibition in *Michigan Bell Telephone Co v Public Service Comm*, 315 Mich 533; 24 NW2d 200 (1946). 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.

In any event, “the 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.).

V. TEST YEAR

DTE Electric’s projected test year is May 1, 2020 through April 30, 2021. The Company normalized and adjusted actual results from the historical test year ended December 31, 2018 to arrive at its filed projected revenue deficiency of approximately \$351 million (4T 464-65; 9T 3414, 3419; Exhibit A-11, Schedule A1) (adjusted to \$343.0 million in this Brief, see Attachment A and B) which produced the equivalent of a fully-projected test year.

The only disagreement with respect to DTE Electric’s projected test year was by RCG witness Mr. Crandall, who claimed that the Commission should adopt an historical test year instead

of a projected test year (9T 2812-15). RCG's position should be rejected because it is contrary to MCL 460.6a(1), which expressly authorizes DTE Electric to use a projected test year. MCL 460.6a states: "A utility may use projected costs and revenues for a future consecutive 12-month period in developing it requested rates and charges."

Mr. Crandall asserted that a "layman's interpretation of the statutory language is that a projected test year for purposes of this case would cover at most the 12 consecutive months after DTE's rate filing in July 8, 2019" (9T 2813). The Commission previously rejected RCG's position as unfounded and contrary to MCL 460.6a(1). (May 2, 2019 Order in Case No. U-20162, p 4). If the Legislature had intended to limit projected test years in this manner, then it "surely could have said so."⁸ Ms. Crozier further explained that Mr. Crandall's proposed interpretation is contrary to well-established regulatory practice, and would illogically create a mismatch between the period on which rates are based and the period in which the rates are implemented (4T 504).

RCG also again asks the Commission to disregard the extensive record in this case, contrary to the requirement that the Commission must base its decision on the record. Const 1963, art 6, § 28; MCL 24.285. RCG's proposal to use an historical test year with selective (and unspecified) adjustments (9T 2815) also violates fundamental due process. The Michigan Supreme Court cited with approval the conclusions of a circuit court judge granting an injunction against such unlawful rates:

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." *Michigan Consolidated Gas Company v Public Service Comm*, 389 Mich 624, 633; 209 NW2d 210 (1973).

⁸ *Lash v Traverse City*, 479 Mich 180, 189; 735 NW2d 628 (2007); *People v McIntire*, 461 Mich 147, 160; 599 NW2d 102 (1999).

Therefore, RCG's proposal should again be rejected, and the Company's May 1, 2020 through April 30, 2021 test year should be used.

VI. 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 ending April 30, 2021 was \$18,251,329,000, which consisted of \$16,789,215,000 of net plant and \$1,462,113 of working capital (9T 3414; Exhibit A-12, Schedule B1, column (d)).

As discussed in Section I, the Company has made a few adjustments to its originally filed Rate Base. Adjustments to working capital include: 1) \$68.0 million reduction to the Other Accounts Receivables – Associated Companies (9T 3240-41); and 2) a \$2 million correction to Accounts Payable (9T 3217). Adjustments to net plant include: 1) a \$14.6 million reduction to plant in service related to contingency for the Blue Water Energy Center (rate base impact of \$11.5 million) (9T 3211; and 2) a \$3.2 million reduction to plant in service related to contingency for the Headquarters Energy Center (rate base impact of \$2.3 million) (9T 3211). DTE Electric's Total Rate Base request as adjusted in this Brief for the projected period ending April 30, 2021 is \$18,167,548,000, which consisted of \$16,775,456,000 of net plant and \$1,392,092,000 of working capital.

A. Working Capital – Accounts Receivable and Accounts Payable

Staff proposed to eliminate the balance within Other Accounts Receivable – Associated Companies in the total amount of \$88,292,000 as shown on Exhibit A-12, Schedule B4, line 12 (9T 3240-41). DTE Electric agrees with the elimination of \$68,020,626 due from the Reduced Emissions Fuels (REF) companies and has adjusted its working capital amount as discussed in Section I above. DTE Electric also agrees with eliminating the remaining \$20,271,408, but only if

the related financing source is also eliminated from Accounts Payable. The inter-company receivable is effectively financed with the inter-company accounts payable because affiliate balances are settled on a net basis. Therefore, \$20,271,408 of the \$76,797,000 of Accounts Payable – Associated Companies (shown on Exhibit A-12, Schedule B4, line 47) should also be eliminated, which therefore results in no net change in Working Capital from this adjustment (6T 1560, 1567). Staff also proposed to increase Accounts Payable – Associated Companies by \$2 million to correct an error in the Company’s projected amount (9T 3317). DTE Electric agrees with this increase and has adjusted working capital as discussed in Section I above. Based on these two corrections, the Company now supports a working capital amount of \$1,392,092,000.

B. Working Capital - Prepaid Pension

The Commission previously rejected in Case No. U-20162 ABATE’s proposal in that case to exclude the prepaid pension asset from working capital, but directed the Company in this case “to provide additional evidence on this cost demonstrating that the prepaid pension asset should be included in working capital, including the source of the funding of the prepaid pension asset” (May 2, 2019 Order in Case No. U-20162, p 50).

Accordingly, Ms. Uzenski explained that the prepaid pension asset is properly included in working capital because it is a reasonable and prudent investment that results from the Company’s policy of funding its pension trusts to minimize its pension costs. Customers benefit because increased pension funding results in higher pension balances and higher compounded returns on investments. The Company can also deduct the contributions made to its pension trusts from its income taxes (6T 1541-42, 1572-73). Since December 31, 2002, when the Company had a net pension liability of \$37.6 million, the prepaid pension asset has accumulated to \$757.7 million as of December 31, 2018 (6T 1542-43; Exhibit A-12, Schedule B4.4), and is projected to be \$836.7

million at April 30, 2021 (6T 1569, 1572). Ms. Uzenski further explained that the source of funding of the prepaid pension was from investor capital (6T 1543).

ABATE witness Ms. Alderson proposed a \$794.3 million disallowance of prepaid pension asset within working capital, claiming that it has not been fully funded by investor capital, and that the Company did not prove that contributions were reasonable and prudent (7T 1804-12). Ms. Uzenski disagreed, emphasizing again that the accumulation of the prepaid pension asset was funded through investor capital. She explained that the pension asset represents that difference between pension funding and pension expense. Customer rates include pension expense (The Company only recovers through rates the annual pension costs recognized pursuant to ASC 715-30). Since the prepaid pension asset represents the cumulative difference between the annual pension costs and the Company's annual contributions to the pension trust, the prepaid pension asset could only be from investor capital (6T 1543, 1568).

Ms. Uzenski further explained that customers have funded approximately \$2,073.4 million (the amount expensed). Total funding was \$2,952.0 million. The difference between customer funding and total funding results in total investor funding of \$836.7 million, which is the ending prepaid pension asset at April 30, 2021. She also explained the underlying calculations, which are reflected on Exhibit A-40, Schedule EE3 (6T 1570-71).

Ms. Alderson suggested that a portion of the prepaid pension asset was funded through market returns (7T 1807). Ms. Uzenski explained that it is incorrect to include the actual return on assets as a component of the prepaid pension expense. The prepaid pension asset is the difference between pension funding and pension expense. Pension expense is not based on the *actual* return on assets; it is based on the *expected* return on assets, which is a non-cash credit to expense (6T 1569).

Turning to Ms. Alderson's suggestion that the Company's funding might not be reasonable and prudent, it is undisputed that the Company is required to make minimum annual contributions to fund its pension liabilities pursuant to ERISA and related regulations. Funding above that amount is discretionary, but Ms. Alderson acknowledged that investor funding may be found reasonable to include in rate base if the Company shows that it benefits customers (7T 1809-10). As of December 31, 2018, the Company's pension plan assets were \$811.3 million less than the pension liability, which demonstrates that the pension trust is not over funded (6T 1543; Exhibit A-12, Schedule B4.4). Ms. Uzenski further explained how discretionary contributions to the pension fund benefit customers through lower costs:

As contributions are made to the pension fund, additional returns are expected and reflected as a reduction to pension expense. The estimated impact of the Company's discretionary funding is identified on Exhibit A-40, Schedule EE4, which shows that if the Company only funded up to the amount of pension expense and thus eliminated the prepaid pension asset, then the net impact on the Company's proposed revenue requirement, would be an increase of at least \$16.0 million. There would also be Pension Benefit Guarantee (PBGC) premiums that would arise from an underfunded plan as measured under ERISA. This exhibit recognizes the increase in pension costs due to lower assets and a reduction in Deferred Income Taxes arising from the deductibility of pension funding. Since Deferred Income Taxes are included in the overall cost of capital at zero cost, it is equivalent to a reduction in rate base. These two benefits sum to \$72.8 million as shown on line 11. In contrast, the reduction in the Company's revenue requirement due to the elimination of the prepaid pension asset is \$56.8 million, shown on line 14. This provides the demonstration of the benefit to customers of the Company's policy to contribute discretionary pension funding, and that the contributions were both reasonable and prudent. [6T 1572-73.]

In summary, the Company has demonstrated that the prepaid pension asset was funded by investors, and that it benefits customers by reducing the pension expense included in rates. Therefore, ABATE's proposal to exclude the prepaid pension asset from rate base should be rejected (6T 1560, 1573).

Pension Expense Tracker

Ms. Alderson's concern about variances between booked expense and the amount assumed in rates does have some merit, however, in connection with projected pension expense in this case, due to the current volatility in the financial markets.

As explained by Mr. Cooper, as of August 31, 2019 (as compared to December 31, 2018), the net effect of lower discount rates and higher 2019 investment return increased the Company's total pension cost for the projected test year by \$17.4 million. This increase, net of the impact of costs capitalized, produced a \$12.0 million increase in pension expense for the projected test year (5T 963-64; Exhibit A-33, Schedule X4). This calculation highlights the volatility of pension costs in the current financial market environment. This amount as of August is indicative of a potential increase in the Company's projected revenue requirement, but remains subject to further adjustments based on the actual interest rate environment at December 31, 2019, and actual asset returns for all of 2019 (5T 964).

In recognition of this volatility in pension costs, Ms. Uzenski proposed to address Ms. Alderson's concern that the Company's future pension costs may be different than the pension costs recognized in rates by implementing a pension expense tracker that would defer (as a regulatory asset or liability) any difference in the Company's actual net pension expense in future years from the \$50.7 million reflected on Exhibit A-13, Schedule C5.12.1. This proposal is similar to the ongoing deferral of negative Other Post-Employment Benefit (OPEB) expense (6T 1570). In Case No. U-17767, the Commission agreed that OPEB expense should not be based on temporary savings and approved the Company's proposed deferral treatment. The MPSC should reason similarly in this case that temporary expense levels should not be the basis for on-going rates.

C. Fossil Generation

Mr. Morren explained and supported total Fossil Generation capital expenditures of \$375.6 million for 2018, \$697.3 million for 2019, \$295.4 million for the 4 months ending April 30, 2020, and \$519.8 million for the twelve-month period ending April 30, 2021 (Exhibit A-12, Schedule B5.1, page 1, line 13, columns (b), (c), (d) and (f)). He provided an overview of expenditures for routine and non-routine projects as reflected on Exhibit A-12, Schedule B5.1, page 1 (5T 589-92). He described the major non-routine capital projects (5T 592-99; Exhibit A-12, Schedule B5.1, page 2), and the major routine capital projects (5T 599-616; Exhibit A-12, Schedule B5.1, pages 4-7). The routine expenditures for all Units were \$207.4 million in 2018, and are projected to be \$237.3 million for 2019, \$75.4 million for the first 4 months of 2020, and \$187.1 million for the 12-month period ending April 30, 2021 (Exhibit A-12, Schedule B5.1, page 3).

DTE Electric is making routine ongoing investments in its existing fossil generation fleet to maintain safe, environmentally-compliant, reliable and efficient operations. The Company's Fossil Generation organization anticipates that certain coal-fired generating units will be retired years before others, so it created a two-tiered maintenance and capital expenditure allocation strategy. Belle River and Monroe are the Tier 1 units with the greatest long-term value to customers. The remainder of the coal-fired units (St. Clair, River Rouge, and Trenton Channel) are Tier 2 (5T 583-84, 616).

The Tier 2 retirement schedule has been modified since Case No. U-20162. Because of extensive repairs identified during a February 2019 outage at St. Clair Unit 1, the Company requested approval from MISO to retire the unit. MISO approved the Company's request with an

effective retirement date of March 27, 2019.⁹ Based on several factors including economic value, reliability benefits, local community impacts, and environmental benefits, River Rouge Unit 3's previously-planned 2020 retirement date has been altered. The Unit will now end the use of coal in 2020 and will continue to operate until 2022 on recycled industrial gas and natural gas. This plan allows for use of the recycled industrial gases to produce electricity instead of flaring directly to the environment,¹⁰ economically supports the surrounding community in River Rouge, and allows additional time to resolve reliability concerns, particularly considering the retirement of St. Clair Unit 1. A MISO Attachment Y analysis for River Rouge Unit 3 determined that if the unit was to retire in 2020, firm load shed would be required during certain electrical grid conditions (DTE Electric would be required to shut off power to some of its firm customers to ensure transmission grid reliability).¹¹ Firm load shedding is one of the countermeasures that MISO may use to maintain necessary transmission grid stability, but the Company does not believe this to be in the best interest of its customers. The retirements of the St. Clair Power Plant (Units 2, 3, 6, and 7) and the last unit at Trenton Channel Power Plant (Unit 9) are also planned for 2022. The Tier 2 retirements are contingent on the timely start-up of the Blue Water Energy Center (BWEC). The Trenton Channel

⁹ The Commission previously approved St. Clair Unit 1 capital expenses for the May 2018 through April 2019 test year, but noted the then-recent shutdown and stated that “the Commission expects the utility to repurpose the capital expense associated with St. Clair Unit 1 on this record after the date of the shutdown of that unit for use on other units in need, and to present that expense information in its next rate case” (May 2, 2019 Order in Case No. U-20162, p 13). Mr. Morren testified that approximately \$0.2 million associated with St. Clair Unit 1 was redirected to support the remaining operating units at the St. Clair power plant (5T 620).

¹⁰ The industrial gasses are a byproduct of the coke and steel-making process. Recycling the gasses as a fuel allows the energy in the fuel to be recaptured rather than wasted to the atmosphere through flaring. Recycling industrial gasses also eliminates the need to burn fuel at another location to produce the electrical energy that River Rouge Unit 3 is forecasted to produce. Operating River Rouge Unit 3 on industrial gasses will also result in significantly reduced emissions as compared to operating it on coal (5T 657-58).

¹¹ MEC/NRDC/SC/CUB witness Dr. Letendre criticized the Company's reliance on the MISO Attachment Y analysis, but offered no evidence to support his speculation that the potential load shed conditions might no longer exist (9T 3775). The Company has no reason to believe that the conditions identified in the MISO Attachment Y analysis are no longer valid (5T 656).

Unit 9 retirement is also contingent on the resolution of the grid reliability issues caused by this retirement (5T 576-79, 624-25, 655-58).

In projecting the proposed retirement dates for these Units, several factors were considered. As indicated above, MISO's permission is needed to retire units pursuant to the MISO Attachment Y process. The Company also evaluates factors including the age and condition of the generating unit, workforce planning, local community impacts, resource adequacy, and grid reliability when determining whether a generating unit should be retired and the timing of that retirement (5T 620-25). The Commission's April 27, 2018 Opinion and Order in Case No. U-18419, pp 48-49 recognized this as well:

The Commission agrees with DTE Electric that, although there is a possibility that one or more of the Tier 2 units might retire early, any plans to do so should await the outcome of the Company's 2019 IRP analysis and the results of MISO's Attachment Y reliability study. Other matters such as workforce and local government tax impacts may also be considered in a decision of this magnitude." [5T 620-21.]

Mr. Burgdorf's direct testimony provided: (1) an overview of the MISO resource adequacy requirements and capacity market (5T 808-12); (2) an overview of the capacity import limitation (CIL) enforced by MISO in the Planning Resource Auction (PRA) and its impact on Zone 7, including a calculated 164 MW Effective Capacity Import Limit (ECIL) for Zone 7 in Planning Year 2019/20 (5T 812-13) and (3) an overview of the MISO Zone 7 capacity position for Planning Year 2019/2020 as well as forecasted capacity positions for Planning Years 2020/21 and 2021/22 (5T 813-17). He expressed concern over capacity shortages because Zone 7 was only 251 MW long to its Local Clearing Requirement (LCR, the minimum amount of unforced capacity that must be located in a Local Resource Zone to maintain reliability) in Planning Year 2019/20, and the forecasted Zone 7 capacity length to the LCR remains very tight at less than 2% of LCR in Planning years 2020/21 and 2021/22. Earlier than expected retirement of any of the more than 1,600 MW

that comprise the remaining Tier 2 fleet prior to their planned retirement in 2022 would exacerbate this issue and likely result in Zone 7 being short of capacity. If that happens, then the MISO auction clearing price would be set to the Cost of New Entry (CONE) and the probability of a loss of load event (available capacity is insufficient to serve demand) would exceed the federal reliability standards that govern the resource adequacy planning process (5T 816-17). Updated data (further discussed in section VI. A. 1 below) confirms these concerns (5T 822-25). Mr. Morren concluded:

Continuing operations of the more-than 1,600 MW of Tier 2 electric generating units until the planned retirement date of May 2022 is in the best interest of our customers and needed to provide sufficient capacity to Zone 7 and support grid reliability while allowing local communities to plan for the impacts of the previously announced retirement dates. [5T 625.]

The Company's Fossil Generation planning process is 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 Fossil Generation reliability performance and reducing costs (5T 586-89). There are different operating performance metric targets that drive the capital and O&M expenditures for each tier of units. Investments in Tier 1 coal units are designed to achieve first quartile reliability performance as measured by random outage factor (ROF). Investments in Tier 2 units are limited to those required to maintain safe and environmentally-compliant operations until the units are retired (5T 579, 583-84, 616).

ABATE witness Ms. York asserted that \$18.1 million of routine capital forecasted expenditures for three projects (the Belle River Unit 2 LP Turbine Blade Replacement, the Greenwood Unit 1 Main Unit Transformer Replacement, and the Monroe Unit 4 Generator Stator Rewind) should be disallowed, reasoning that the Company did not provide information demonstrating that the costs would be incurred during the bridge period or projected test year (7T 1943-44). To the contrary, the Company provided details on the timing of the periodic outages

associated with the three projects in discovery responses (Exhibit A-39, Schedule DD2). All of the outages and associated projects are being executed during the timeframe of this case (5T 642-43).

AG witness Mr. Coppola similarly recommended that \$7.2 million forecasted for the Belle River HP Turbine replacement project be disallowed, indicating that there is uncertainty regarding when the project will be undertaken (9T 2987). Mr. Coppola apparently ignored or misread the Company's testimony, exhibits and discovery response. The project has now been completed as scheduled and was appropriately included in this case (5T 643).

Mr. Coppola repeatedly recommended disallowances for 2019 and 2020 capital expenditures, asserting that the "rate case forecast is not supported by the project approval document" (9T 2988, 2990-92). Mr. Morren explained that a Project Authorization Template (PAT) form authorizes the initiation of a project. Fossil Generation updates its forecasts for all of its capital projects monthly, but project approval document updates occur only as needed. The Company's forecast in this case relied on the best information available, which was the latest (updated monthly) project forecasts, and not the PAT project-approval documents. Therefore, there is no merit in Mr. Coppola's proposed disallowances based merely on a comparison of requested amounts to PAT forms (5T 644-46).

Mr. Coppola similarly suggested that the Company is prematurely requesting funds for certain routine capital projects that are "ballpark" estimates not approved by management (9T 3987-94). To the contrary, the Fossil Generation Capital Governance Board (CGB, which consists of plant directors, the Director of Engineering, and the Senior Vice President of Fossil Generation) reviewed and approved the funding allocations shown on Exhibit A-12, Schedule B5.1 (5T 644, 646).

Mr. Coppola further asserted that there should be a \$12.7 million blanket disallowance for seven routine capital projects in 2021 because they appear to be “ballpark” placeholder estimates that lack specific approval (9T 3994). Mr. Morren disagreed, explaining that the funding was approved as discussed above, and the projects are not placeholders; instead, they are specific projects that are mainly associated with the Greenwood periodic outage. Mr. Morren further explained and supported each project. Therefore Mr. Coppola’s proposed disallowances are unwarranted and should be rejected (5T 646-48).

Non-routine capital investments for all Units were \$168.1 million in 2018, and are projected to be \$460.0 million for 2019, 220.0 million for the first 4 months of 2020, and \$332.7 million for the 12-month period ending April 30, 2021 (Exhibit A-12, Schedule B5.1, page 2). These expenses are driven by steam power generation upgrades with a heavy focus on environmentally-mandated work at the Tier 1 coal plants, decommissioning and environmental remediation projects at steam power generation plants, upgrades at the Ludington Pumped Storage Plant, and construction costs for the new BWEC,¹² and combined heat and power (CHP)¹³ plant (5T 589).

Mr. Coppola recommended disallowing the Monroe Bottom Ash Basin Closure Coal Combustion Residual (CCR) project (\$40,785,000), reasoning that “[u]ntil EGLE issues new compliance rules that have been approved by the EPA, it is premature to spend millions of dollars on this project” (9T 2997). To the contrary, and as the Company explained in a discovery response (Exhibit A-39, Schedule DD3), the state CCR permitting programs must be at least as protective as

¹² The Commission granted three certificates of need (CONs) for a 1,100 MW CCGT plant, which is needed due to DTE Electric’s pending retirement of Tier 2 coal-fired generating units (April 27, 2018 Opinion and Order in Case No. U-18419).

¹³ DTE Electric developed a new 34 MW CHP plant as part of infrastructure upgrades to Ford Motor Company’s Research and Engineering Center complex. The Commission found that the CHP plant should be included in rate base, but with a disallowance of 10% of incremental plant additions for the test year (May 2, 2019 Order in Case No. U-20162, p 18). The disallowance is reflected at line 31 of Exhibit A-12, Schedule B5.1, page 2 (5T 599).

the federal CCR rule, so the state program will not lessen the cleanup requirement. Moreover, the EPA's pre-publication draft rule released in November 2019 would require initiating the closure of the Monroe Bottom Ash Basin by August 2020, rather than October 2020 under the current rule. The Company has only months to initiate the closure under either the current or draft rule. Therefore, the AG proposed disallowance is not justified (5T 649-50, 750).

ABATE witness Ms. York recommended full disallowance of the Monroe Bottom Ash Basin Closure CCR project because it had not received "full BOD approval" (7T 1940). Mr. Morren responded by explaining that the Company expected full BOD approval on December 4, 2019, and that this is not an elective project. The project is environmentally mandated by being subject to the "forced closure" requirements of the CCR rules (5T 651).¹⁴

Ms. York alternatively recommended partial recovery based on a comparison to project approval documents (7T 1940-42). As discussed above, project approval documents do not necessarily reflect the Company's latest forecast that is used for rate case purposes, and do not constitute a sound basis for any disapproval (5T 645-46, 652). Ms. York also ignored certain projects. In response to Staff audit request JJD-3.1, the Company provided a list of five complementary projects that are incorporated into Exhibit A-12, Schedule B5.1, line 13. But Ms. York's Table 4 (7T 1941) includes only two of these projects. Therefore, Ms. York's proposed full and partial disallowances are unjustified and should be rejected (5T 651-52).

Ms. York recommended full disallowance of the Monroe Dry Fly Ash Conversion project, reasoning that construction is not expected to start until after the projected test year in this case, and

¹⁴ MEC/NRDC/SC/CUB witness Dr. Letendre suggested that the Company should be "required to provide a description of how the Company plans to cover CCR-related costs in future years" (9T 3793). Mr. Morren responded by explaining the current status of the CCR Rule, and the Company's plan for compliance with that Rule. At this time, however, certain CCR provisions are not final, and some of the closure dates for CCR sites are decades into the future. It is not fully known what will be required or what the complete costs will be, so Dr. Letendre's suggestion is premature (5T 660-61, 723, 725).

it is unclear whether the Company has received all necessary internal approvals (7T 1937). This recommendation lacks merit because the project is required to comply with ELG regulations mandating zero liquid discharge from the Monroe Fly Ash Basin. The Company expects to receive BOD approval in January 2020. Expenditures required to design, engineer, and procure materials prior to physical construction will occur during the projected test year. These project costs are recorded to construction work in progress (CWIP) and recoverable pursuant to well-established ratemaking practice (5T 653; 6T 1536-37).

Ms. York alternatively recommended a partial disallowance for the Monroe Fly Ash Conversion project (7T 1937). Mr. Morren explained that this recommendation has the same two flaws as Ms. York's recommended partial disallowance for the Monroe Bottom Ash Closure CCR project. First, project approval documents do not necessarily reflect the Company's latest forecast that is used for rate case purposes, and do not constitute a sound basis for any disapproval. Second, Ms. York ignored certain projects that were presented in response to Staff audit request JJD-3.1. The Company provided three complimentary projects that are incorporated into Exhibit A-12, Schedule B5.1, page 2, line 4. But Ms. York's Table 3 (at 7T 1936) includes only one project. Therefore, Ms. York's proposed full and partial disallowances are unjustified and should be rejected (5T 654).

As indicated above, the majority of investments in the Company's fossil generating units are directed at the Tier 1 Monroe and Belle River power plants.¹⁵ Mr. Morren further testified that

¹⁵ Dr. Letendre suggested that the Company should be required to present information and analysis relating to potential retirement dates for Belle River in its next rate case (9T 3788). The Company disagrees because retirement analyses are more comprehensive than simple economic calculations. Additional planning principles must be considered. The proper forum is an Integrated Resource Plan (IRP) case. The Company recently demonstrated in its IRP case (Case No. U-20471) that continuing to operate Belle River to 2029/30 is favorable to customers as compared to retiring it in 2025/26. Dr. Letendre's suggestion constitutes an improper attempt to litigate (or re-litigate) the Company's IRP in a rate case forum. The suggestion is also improper because rate cases are designed to normalize and adjust historical

he prepared two tables [at 5T 618] with data extracted from Exhibit A-12, Schedule B5.1 pages 2 and 3 showing that planned expenditures are being minimized at the Tier 2 coal units as they are moving towards retirement. The Tier 1 units are receiving 75% of total capital for routine capitalized maintenance and 18% for non-routine capital additions, primarily for environmental-related projects. The Tier 2 units are receiving just 7% of the total expenditures for capitalized maintenance and zero (0%) for non-routine capital additions (5T 616-18).

Mr. Morren also provided details regarding the routine capital expenditures at the Tier 2 units, all of which are necessary to operate the units in a safe and environmentally-compliant manner (5T 618-19). He also noted that the Company must continue to perform maintenance on the Tier 2 plants to ensure that they operate safely and are environmentally-compliant until they retire. Some of that maintenance is categorized as capitalized maintenance rather than O&M pursuant to the accounting rules that the Company follows (5T 617).

The projected capital projects and associated expenditures for the Company's fossil generation units are required to support safety, regulatory compliance, environmental compliance and reliability. DTE Electric has also shown that the planned retirement schedule for the Tier 2 units is reasonable and prudent. Therefore, the Company's capital expense recovery should be fully approved.

costs to arrive at a one-year projected test period that is used to determine the Company's revenue requirement and corresponding rates. Dr. Letendre suggests scenario analyses with retirement projections many years into the future. This would likely involve modeling efforts akin to an IRP and result in various parties asserting widely-variable positions about a range of future possibilities. All this is best addressed in an IRP case (and would be a wholly-improper major case effort to squeeze into an already compressed ten-month rate case), so the Commission should reject Dr. Letendre's suggestion (4T 507-508, 543).

1. Tier 2 NPVRR Analyses and River Rouge Unit 3 Retirement Date Discussion

As indicated above, because of extensive repairs identified during a February 2019 outage at St. Clair Unit 1, the Company requested and received approval from MISO to retire the unit. Company witness Ms. Leslie further explained that the Company's decision was supported by a net present value revenue requirement (NPVRR) analysis showing a range of results from \$18 million in favor of retiring the unit in 2019, to \$14 million in favor of repairing the unit and continuing operations until 2022, depending on the capacity price sensitivity selected. The unit was retired March 27, 2019 (5T 759-60; NPVRR results at Exhibit A-12, Schedule B6.1, page 2).

River Rouge Unit 3 is now planned to end the use of coal in 2020 and to continue to operate until 2022 on recycled industrial gases. In addition to the reasons discussed above, Ms. Leslie testified that a NPVRR analysis showed a range of results from \$14 million in favor of continuing to operate the plant through May 2022, to \$1 million in favor of retiring the unit in May 2020, depending on the capacity price sensitivity selected (5T 761-62; NPVRR results at Exhibit A-12, Schedule B6.2, page 2).

MEC/NRDC/SC/CUB witness Dr. Letendre took issue with the range of capacity price sensitivities that the Company used for its River Rouge Unit 3 NPVRR analysis, and asserted that "under any reasonable set of modeling assumptions, retirement in May 2020 is more economical than continued operation through May 2022 on industrial and natural gas. Therefore, any future capital expenditures on River Rouge Unit 3 would be imprudently incurred and should be disallowed" (9T 3779).

Ms. Leslie explained that Dr. Letendre's position lacked merit because the Company assessed multiple capacity price sensitivities to capture the range of uncertainty with capacity prices: (1) zero (\$0) was used as the low end of the range; (2) the Cost of New Entry (CONE)

assessed the highest possible clearing price if an early retirement would cause MISO Zone 7 to not meet the LCR; and (3) 50% of CONE reflected the middle range sensitivity. The Company also used the November 2018 PACE forecast, which was the most recently available at the time of this case filing (5T 772-73).

Dr. Letendre asserted that “[a]ll of these prices, with the exception of the \$0 sensitivity, represent the high end of potential capacity prices” (9T 3752). To the contrary, actual prices paid by the Company in 2017 compare closely to 50% CONE sensitivity. The November 2018 capacity price forecast from PACE is also very close to the 50% CONE sensitivity (5T 773-74). There is similarly no merit in Dr. Letendre’s suggestion that the Company should have considered additional price sensitivities (9T 3752, 3762). The Company used a range of capacity price sensitivities reflecting a reasonable set of capacity price forecasts, so adding additional forecasts is unnecessary (5T 774-75).

Mr. Burgdorf further refuted Dr. Letendre’s suggestion that the Company’s capacity price sensitivities were inflated by explaining (in addition to the discussion above) that a price of CONE is a very real possibility in the next two Planning Years (PY 2020/21 and PY 2021/22). Updated data presented in the 2020/2021 MISO Loss of Load Expectation Study Report published on November 1, 2019 (Exhibit A-32, Schedule W1) significantly reduced the forecasted LCR position that Mr. Burgdorf presented in his direct testimony (at 5T 816), indicating a probable shortage to LCR (*i.e.*, a negative position relative to LCR) in both Planning Years 2020/21 and 2021/22 if River Rouge Unit 3 retires on May 31, 2020 (5T 822-24). The MPSC Commissioners also recently sent a letter to MISO on November 7, 2019, indicating concern about Zone 7 meeting the LCR (Exhibit A-32, Schedule W3).

Mr. Burgdorf further explained that if River Rouge Unit 3 had not participated in the Planning Year 2019/20 PRA, then Zone 7 capacity resources offered into the PRA would have only been 14 MW above the LCR.¹⁶ River Rouge Unit 3 is expected to provide up to 100 MWs of capacity from continued operation on industrial gasses. This additional Zone 7 capacity changes the expected LCR position to positive for Planning Year 2020/21 and possibly Planning Year 2021/22, thus reducing the risk of not meeting the LCR (which would cause the MISO auction clearing price for Zone 7 to be set at CONE). Thus, the Zone 7 LCR position is presently forecasted to be negative (triggering CONE), but this situation may be alleviated by the continued operation of River Rouge Unit 3. This further supports both the Company's use of CONE as the upper-end capacity price sensitivity in the NPVRR, and the Company's decision to continue operating River Rouge Unit 3 on industrial gasses (5T 824-25).

Dr. Letendre asserted that "the Company's favored capacity forecast, developed by PACE, contains a significant error regarding its treatment of the Zone 7 CIL, which results in an overestimation of the Zone 7 capacity price" (9T 3751). Dr. Letendre's assertion is wrong for two major reasons. First, Dr. Letendre's claim that there is an error in the PACE capacity price forecast is based on a flawed premise.¹⁷ Second, the Company did not favor the PACE forecast, but instead considered the range of NPVRR results from four capacity price sensitivities, without weighing each result as more or less likely. Moreover, the collective results of the NPVRR analysis were just

¹⁶ There were only 251 MWs of Zone 7 capacity resources offered into the PRA above the LCR. River Rouge Unit 3 was credited with 237 MWs of unforced capacity (UCAP). (5T 823).

¹⁷ Dr. Letendre claimed that the CIL represents the ability to transfer zonal resource credits of unforced capacity (UCAP), and incorrectly concluded that CIL should be adjusted to an installed capacity (ICAP) basis when used in the ICAP-based PACE forecast. Mr. Burgdorf explained that Dr. Letendre's claim that the PACE forecast's treatment of CIL results in an overestimation of Zone 7 capacity prices is based on a flawed premise that is inconsistent with the purpose of CIL and its utilization by MISO. According to MISO (reflected at Exhibit A-32, Schedule W2), CIL is not a generation asset and is not determined on a UCAP or ICAP basis. Instead, it is simply the MW transfer ability between MISO zones (5T 825).

one factor that the Company considered in its retirement analysis, as discussed above. Therefore, there is no foundation nor merit in Dr. Letendre's suggestion that the Company's analysis was either flawed or biased (5T 775).

There is similarly no merit in Dr. Letendre's criticism that "DTE erroneously mixed absolute values with differences between scenarios throughout the model" (9T 3764). Ms. Leslie explained that the basis of a net present value analysis is to determine the difference between comparative scenarios. The results, whether shown as an absolute value or as a difference, do not impact the overall merit or results of the NPVRR analysis, nor does the use of differences render the analyses meaningless as Dr. Letendre suggested (5T 778).

Dr. Letendre asserted that "DTE has not adequately supported its assertion that continued operation of River Rouge Unit 3 provides value to ratepayers . . . And when critical errors in the Company's analysis are corrected, and more realistic assumptions and sensitivities are tested, the results show that ratepayers are likely better off with the unit retiring in May 2020 as originally planned" (9T 3774).

To the contrary, the Company's NPVRR analysis showed a range of results from \$14 million in favor of continuing to operate the plant through May 2022, to \$1 million in favor of retiring the unit in May 2020, depending on the capacity price sensitivity selected (5T 761-62, 775-76; NPVRR results at Exhibit A-12, Schedule B6.2, page 2). Even assuming that Dr. Letendre's adjustments to the Company's NPVRR are appropriate (which they are not),¹⁸ they still yielded a

¹⁸ The Company disagrees that Dr. Letendre's adjustments are appropriate. For example, he assumed that the Company will continue to pay historic price levels for industrial gases (9T 3773) even though the Company has indicated that the contracts require renegotiation. The existing contracts are indexed to the price of coal supplied to the plant, so they have to be renegotiated because coal will no longer be supplied to River Rouge. The Company is currently in negotiations with the supplier, and expects pricing similar to what was modeled in the Company's NPVRR analysis

mixed range of outcomes. The range of NPVRR outcomes supports continued operation of River Rouge Unit 3 as the most reasonable and prudent path, particularly considering the other non-economic factors such as MISO grid reliability, resource adequacy, environmental considerations, and community impacts.¹⁹ Also, as discussed above, recent information demonstrates that River Rouge Unit 3 provides critical capacity to MISO Zone 7. Dr. Letendre's contrary assertions lack foundation and are otherwise erroneous, so they are entitled to no weight (5T 576-79, 620-28, 655-59, 775-78, 822-25).

With regard to the remaining St. Clair units (2, 3, 6, and 7), the Company's NPVRR analysis showed a range of results from \$43 million in favor of retiring the plant on May 31, 2020, through \$76 million in favor of continuing to operate the plant through May 2022, depending on the capacity price sensitivity selected (5T 763-65; NPVRR results at Exhibit A-12, Schedule B6.3, page 2).

Similarly, the Company's NPVRR analysis for Trenton Channel Unit 9 showed a range of results from \$24 million in favor of retiring the unit on May 31, 2020, to \$38 million in favor of continuing to operate the unit through May 2022, depending on the capacity price sensitivity selected (5T 766-69; NPVRR results at Exhibit A-12, Schedule B6.4, page 2).

Ms. Leslie added that an economic cost and benefit analysis can just provide a general guideline for the reasonableness and prudence of continuing to operate a generating unit. As discussed above, there are several additional factors to consider when determining whether to retire a generating unit, and the Company decided that the best option for its customers is to continue

(5T 658-59, 777). Dr. Letendre also made other calculation changes that he did not explain in his testimony, so it is unclear exactly what he did (5T 785-86).

¹⁹ Dr. Letendre suggested that the Company should effectively gift a payment to the City of River Rouge equal to property taxes that would be lost due to the retirement of River Rouge Unit 3 (9T 3776). The Company disagrees because its property is subject to taxation based on its value under Michigan law. Customers should not be burdened with paying amounts that are not authorized or required by law (5T 657, 715).

operating the St. Clair and Trenton Channel power plants until their planned retirement in May 2022 (5T 765-66, 769).

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 2018 through the projected period ending April 30, 2021. The capital expenditures of \$4.0 million for 2018, \$3.9 million for January 2019 through April 2020, and \$2.5 million for the projected 12-month period ending April 30, 2021 (as shown on Exhibit A-12, Schedule B5.2), relate to improving safety, meeting environmental requirements, upgrades to increase efficiency and reliability, and/or replacement of end-of-life equipment. The capital expenditures are reasonable and prudent, and necessary to maintain and/or improve Fuel Supply operations and MERC's coal transshipment capabilities (9T 3923-27; Exhibit A-12, Schedule B5.2, columns (b), (e) and (f)). There is no disagreement. Therefore, the expenditures should be approved.

D. Fermi 2

Mr. Davis described the operation of the Fermi 2 Nuclear Power Plant (Fermi 2) and supported Fermi 2's 2018 actual, as well as projected, capital expenditures through April 30, 2021. The Nuclear Regulatory Commission (NRC) has licensed Fermi 2 to operate through 2045. The capital expenditures (and O&M expenses discussed in section VII. C. 4) that Mr. Davis discussed throughout his testimony reflect reasonable and prudent measures to ensure the safe and reliable extended operation of Fermi 2 (9T 3430-31, 3445, 3460).

The Company's 2018 nuclear capital expenditures totaled \$240.3 million, as listed on Exhibit A-12, Schedule B5.3, page 1, line 11, column (b). The projected capital expenditures are \$324.0 million for the sixteen-month interim period ending April 30, 2020, and \$102.8 million for

the twelve-month period ending April 30, 2021 (9T 3432; 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 routine maintenance and smaller-scale project capital expenditures associated with maintaining Fermi 2's various assets (9T 3435). For example, one project is the replacement of the Integrated Plant Computer System (IPCS), which is necessary to address the aging and obsolescence of a key digital asset (9T 3436-37; Exhibit A-12, Schedule B5.3, page 2, line 8, reflects 4.9 million, \$11.6 million, and \$3.4 million of expenditures in the historical, interim, and projected test year periods).

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. For example, the replacement of the Fermi 2 Main Generator is necessary to address both a design vulnerability and overall reliability of the particular model generator, and thereby support Fermi 2's reliable operation through 2045 (9T 3437-38; Exhibit A-12, Schedule B5.3, page 4, line 2, reflects \$14.1 million, \$63.7 million, and \$14.6 million of expenditures in the historical, interim, and projected test year periods).²⁰ Mr. Davis also discussed the Underground Safety-Related Service Water Piping project, the Boraflex fuel storage racks project, the Reactor Recirculation Motor-Generator (RRMG) Set Replacement project, and the drywell cooler projects, and emphasized that none of the capital expenditures for the projects include contingencies (9T 3438-42).

²⁰ DTE Electric underspent 2018 Nuclear Generation capital by \$11.9 million, which was driven primarily by the retiming of the Main Unit Generator project. Certain engineering and manufacturing activities that were expected to occur in 2018 have been retimed into 2019 and 2020 (9T 3842).

Mr. Davis also explained the timing of Fermi 2's plant refueling outages (9T 3434-36), and the components of Nuclear Fuel capital expenditures (9T 3443-45). He supported the expenditures as reasonable and prudent (9T 3444-45; 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. 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 (9T 3431, 3445-46). There is no disagreement, therefore, the expenditures should be approved.

E. Distribution Operations (DO)

The Company's Distribution Operations (DO) organization focuses on the design, construction, maintenance and operation of the Company's distribution system (4T 123). DTE Electric's distribution system is aging and, in many cases, equipment is operating beyond typical design life. A combination of this aging infrastructure, with its associated reliability issues, along with growth in economic activity in the region, is driving the need for higher capital expenditures to upgrade electric infrastructure in a way that reduces risk, improves reliability, and helps manage costs. Investments in technology are also needed to improve preparedness for catastrophic events and provide better response time during outages, as well as support the evolving way that customers will use the grid, as distributed energy resources (DER) and electric vehicle (EV) penetration increase (4T 238).

DTE Electric also developed, at the Commission's direction, the Five-Year Investment and Maintenance Plan (Five-Year Plan) based on a careful evaluation of asset conditions and customer

needs. The Company evaluated a broad portfolio of investments and prioritized them based on their ability to meet goals that are in the best interest of customers. This case represents an evolution of the investments contemplated in the initial years of the Five-Year Plan. The costs described below provide the electrical infrastructure funding needed to support customer needs and improve reliability (4T 238).

Capital expenditures totaled \$832.4 million in 2018, and are projected to be \$850.8 million for 2019, \$280.0 million for the four months ending April 30, 2020, and \$853.7 million for the projected test year 12 months ending April 30, 2021 (Exhibit A-12, Schedule B5.4, page 1, line 22, columns (b), (c), (d), and (f)).²¹

Mr. Bruzzano supported the actual and projected expenditures shown on Exhibit A-12, Schedule B5.4 as reasonable and prudent based on past expenditures, the projected requirements for labor and material needed for the safe and reliable distribution of electric power, and the investments that are needed to maintain and improve service to DTE Electric's customers (4T 227). He also responded to various Intervenor suggestions (further discussed below), which should all be rejected because those suggestions would be detrimental to customers by reducing the Company's ability to safely and reliably operate the electric distribution system, and make the important strategic investments that are needed to make the grid more resilient and ready for a future characterized by a greater level of DER and EVs (4T 242).

Mr. Bruzzano also explained the forecasting methodology for base capital (4T 211-17). AG witness Mr. Coppola agreed with the Company's five-year normalization of capital expenditures from 2014 to 2018, but asserted that "it should be done using actual capital expenditures from prior

²¹ Pages 1 and 2 of Exhibit A-12, Schedule B5.4 provide a high-level overview of needed capital. Pages 3 to 9 provide additional support including forecasting methodology and project lists. Exhibit A-23, Schedules M-3 through M-6 provide detailed descriptions of each project or program listed in Exhibit A-12, Schedule B5.4 (4T 218). Mr. Bruzzano also provided detailed explanations of Exhibit A-12, Schedule B5.4 (4T 218-25), and Exhibit A-23 (4T 225-26).

years, not by recasting numbers with additional assumed costs for prior year inflation” (9T 2973). Mr. Bruzzano explained that the AG’s position is incorrect. Instead, prior years’ expenditures must be expressed in a constant-dollar denomination because the value of a dollar changes over time due to inflation (for example, the purchasing power of a dollar in 2014 is not the same as the purchasing power of a dollar in 2018). Therefore, the Company properly brought the expenditures to a common 2018-dollar denomination (using the CPI for 2014, 2015, 2016 and 2017 expenditures, as shown on Exhibit A-31, Schedule V-2, page 30) and then averaged them to calculate the starting point for projections (4T 245-47). The Company’s methodology is also consistent with the methodology that the Commission approved in past cases (4T 211, 228, 247-48). Therefore, the AG’s proposed methodology should be rejected.

There is similarly no merit in Mr. Coppola’s further proposals to disallow inflation in projected periods, or in the alternative to limit inflation to 2% beginning in 2020 (9T 2974-77). The AG’s proposals are unfounded and unreasonable because the Company has presented evidence that it experiences inflationary pressures (4T 249-51). See also sections VIII. C. 1 (regarding Inflation on O&M Expense) and VIII. C. 5 (Distribution Operations O&M Expenses) for further discussions regarding inflation.

1. 2018 Actual Expenditures versus U-20162 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 cost of prudently-incurred capital expenditures for used and useful assets that it has deployed to benefit customers.²² Under

²² 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

general ratemaking principles, the Company is entitled to the return “of” and “on” its investments in providing utility service.²³ 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, and the Company must have the flexibility to adjust to unexpected events, such as severe storms, and deploy capital and resources in a way that best serves customers.²⁴

In Case No. U-20162, the Staff requested that the Company identify programs where spending was significantly above the forecasted amount, the amount of overspending, and an explanation for why the overspending occurred. Mr. Bruzzano explained that variations from forecasted amounts can be expected for a variety of reasons. The most significant variations are driven by weather, since the Company’s projections for Emergent Replacements are based on a five-year average. The Company does not have discretion in responding to weather events that cause power outages or damage to the electrical system (4T 130).

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).

²³ 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).

²⁴ 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 \$22.3 million more in 2018 than what was forecasted in Case No. U-20162 (approximately 2.8%).²⁵ Most of this difference was due to higher-than-projected Emergent Replacements, which were approximately \$144 million more than the forecast (4T 132).²⁶ Emergent Replacement – Storm & Non-Storm was higher than forecast because the level of events that caused the Company to perform repairs increased by more than 40% over the five-year average, driven by significant weather events and equipment failures. This work to replace equipment must be addressed immediately. Deferring the work and associated costs would leave customers without power for unacceptably long periods of time, leave the system at risk for additional equipment damage and further customer outages, and potentially leave equipment in a temporarily-repaired condition with hazards unaddressed (4T 133-34). The retirement units, quantities replaced, and material costs are shown in Table 7 (Storm) and Table 8 (Non-Storm). (4T 134-35). The largest contributor to Emergent Replacement – Substation Reactive was the cost associated with the failure of the Plymouth substation at the end of 2017, with repairs continuing well into 2018. This work cannot be deferred because when substation equipment fails, it can leave a large number of customers without power for extended periods of time and significantly reduce the capacity that is needed to serve customers in the event of additional failures (4T 135-36). All of these expenditures were necessary to restore safe and reliable service to customers. The costs were reasonably and prudently incurred, so they should be included in the rate base approved in this case (4T 131-32).

²⁵ The Order from Case No. U-20162 included \$790.9 million of distribution plant expenditures in rate base, which was \$41.5 million less than the actual amount that was prudently incurred in 2018 (4T 137; Exhibit A-12, Schedule B5, line 7).

²⁶ Customer Connections, Relocations & Other spending was approximately \$6 million more than the forecast, before Contribution in Aid of Construction (CIAC). Partly in response to the overspending in Emergent Replacements, there was a reduction in spending for Strategic Capital programs, but there were also other factors that contributed to this underspending, as described in Exhibit A-23, Schedule M1, pages 2-4 (4T 132-33, 136-37).

2. The Company's Projected DO Capital Expenditures

Mr. Bruzzano explained that distribution grid modernization²⁷ is important because the electric power system is experiencing significant changes, driven by evolving customer needs and technological innovations. DTE Electric's near-term investment and maintenance plan is aimed at reducing risk, improving reliability and managing costs for the Company's customers primarily by addressing aging infrastructure; however, it is also important for the Company to make investments that will prepare the grid for a future in which DER, such as battery storage, solar generation and demand response (DR) programs, along with higher EV penetration will fundamentally alter the way the grid operates (4T 138).

DTE Electric is working to understand the potential future operation of the grid and engaged EPRI to provide a perspective on how the Company's current investment plan aligns with the requirements of a modern grid. EPRI found that "DTE is currently in Stage 1 of grid modernization with a primary focus on a refresh of its aging physical infrastructure, modernizing key components of its sensing, communications, and operational systems; and targeting prioritized grid modernization. Their plan is in alignment with its stated objectives and with modernization efforts that have been established nationally" (Exhibit A-23, Schedule M9). Based on its detailed analysis of system conditions and investment priorities and as further supported by EPRI's assessment, DTE Electric plans to continue focusing its investments on aging infrastructure and core grid technology in the near term.

ELPC witness Mr. Villareal asserted that the Commission should not give weight to the EPRI report "because the report does not make any attempt to compare DTE's plan against any

²⁷ The Electric Power Research Institute (EPRI) developed a report for DTE Electric (Exhibit A-23, Schedule M9) explaining that grid modernization "generally refers to actions that make the electric system more fully integrated – one that is highly flexible, reliable, resilient, accessible, responsive, and interactive."

other utility's distribution plan" (9T 2688). There is no sound basis for Mr. Villareal's suggestion that the lack of a comparison to other utility plans somehow invalidates the work of industry experts who assessed DTE Electric's plan against the well-supported, well-established and widely-accepted Department of Energy (DOE) "Next Generation Distribution Project" framework (DSPx). (4T 273-76). Also, as the EPRI report points out, each distribution system has a unique starting point, set of drivers and objectives, and policy considerations (4T 275; Exhibit A-23, Schedule M9, p 5).

Mr. Bruzzano further explained that the Distribution Investment and Maintenance Plan in this case is an evolution of the Five-Year Plan that was submitted in Case No. U-20147, and which also formed the basis for projected DO capital expenditures in Case No. U-20162. The projections from the original Five-Year plan were revised based on an updated system assessment, changes in known customer requirements, and project completions and deferrals experienced in 2018 (4T 146).

Mr. Villareal asserted that the Commission should "[n]ot give weight to DTE's investment strategy built upon its 5 Year Plan, because it lacks sufficient detail to allow the Commission to rely on it" (9T 2688). To the contrary, the Five-Year Plan provided a detailed overview of the Company's asset and system conditions, and clearly laid out the strategic investments needed to address asset and system issues by focusing on investments reducing risk, improving reliability and managing costs, in accordance with Commission orders. Also, as indicated above, the Company's investment strategy and proposed expenditures do not simply rely on the Five-Year Plan, but instead have evolved from it and are supported in detail by expert testimony and exhibits (4T 146, 176-78).

MEC/NRDC/SC/CUB witness Mr. Jester observed that the Commission denied the proposed Infrastructure Recovery Mechanism (IRM) in Case No. U-20162, and therefore asserted that "it is reasonable to conclude that the Commission perceived the distribution plan to be insufficiently persuasive" (9T 3812). Mr. Jester's position is unfounded and contrary to the May 2,

2019 Order in Case No. U-20162, p 20 (see, for example, p 20: “The five-year plan filed by the company complies with the Commission’s prior orders and provides significant and useful information on future system needs”).

Mr. Jester then attempted to leverage his reliance on the Commission’s decision on the proposed IRM by suggesting that the Commission should not approve capital investments in this case. He claimed for example that “DTE Electric’s proposals in this case largely reflect the next tranche of spending on the distribution plan that would have occurred pursuant to the IRM” (9T 3812), but acknowledged that “I am not offering an itemized analysis of the distribution plan spending that is proposed in this case” (9T 3813). In contrast to Mr. Jester’s position (based on an unfounded connection to the IRM and admittedly no analysis), the record reflects that the Company evaluated a broad portfolio of investments and prioritized them based on their ability to meet goals that are in the best interest of customers. This case represents a progression of the investments contemplated in the initial years of the Five-Year Plan. The costs outlined in this brief (and further detailed in the record) provide the electrical infrastructure funding needed to support customer needs and improve reliability. Moreover, projected capital expenditures are consistent with the forecast from Case No. U-20162, and the largest strategic capital expenditures in this case are continuations of projects and programs that were included in Case No. 20162 (4T 238, 270-72; Exhibit A-12, Schedule B5.4; Exhibit A-23, Schedule M2).²⁸

The Company has endeavored to maintain consistency in spending categories. Comparing the forecast from Case No. U-20162 to the present forecast, for the period 2019-2020, the aggregate

²⁸ Mr. Jester further recommended that “the Commission order DTE Electric to file the distribution plan itself and a related proposal for ‘outcome and output-based performance metrics and corresponding ratepayer protections’ within 6 months after the Commission’s Order in this case” (9T 3814). The Company disagrees because the Commission has already set June 30, 2021 as the date for submitting the next distribution plan in Case No. U-20147. This date allows sufficient time for the current stakeholder collaboratives to be summarized by the Staff, with the Staff’s report (planned for April 2020) providing guidance in advance of the June 30, 2021 deadline (4T 272-73).

expenditures are in line with the prior forecast (0.5% difference in aggregate); however, there are changes in the individual categories, driven by an increase in Base Capital (Emergent, Customer Connections, Relocations), which has been offset by a reduction in planned Strategic Capital (4T 157). Emergent Replacements has been adjusted upward because the Company has experienced increasing numbers of emergent events (4T 158). For Customer Connections, Relocations & Other, the Company is adjusting its forecasting methodology to simply reflect the prior year's expenditures plus inflation, instead of booked New Business projects (4T 159-61). There have also been changes to the scope of the Gordie Howe International Bridge (GHIB) project that have increased the project's total cost and delayed its timing (4T 161-62). Strategic Capital projects and programs were adjusted for a variety of reasons, including permitting and changes in system loading conditions, and to manage aggregate capital expenditures in light of the higher level of Base Capital (4T 162; Exhibit A-23, Schedule M2 provides further explanation). The plan could be further adjusted, and the Company must remain flexible to respond to external factors, such as extreme weather conditions and equipment failures, and changing customer needs (4T 162).

Mr. Coppola proposed a \$8,950,000 disallowance for the GHIB project (9T 2979), asserting that the "relocation raises questions about the competency of the original work done and the decision to choose the original location" (9T 2980). It is incorrect for Mr. Coppola to suggest that the Company chose a location for its infrastructure and then changed it. Instead, there has been a concerted effort to minimize costs. During the early stages of the project, the Windsor Detroit Bridge Authority (WDBA) attempted to reduce the project's cost by requesting that the Company not relocate its electrical system infrastructure from the area that would become the Port of Entry (POE), but rather leave it in place. As the project progressed and more information was obtained, however, it was determined that the soil conditions in the POE were such that the soil would need

to be pre-loaded to reduce future settling and that the infrastructure would have to be relocated to protect it from damage.²⁹ The decision to incur the additional cost is reasonable and prudent because it safeguards the integrity of the Company's equipment. The relocation cost is also the same as it would have been if the relocation had been within the project's original scope. There is no relocation cost increase due to the timing of the decision (4T 252-56, 332-33).

There is similarly no merit in Mr. Coppola's further assertions that "this is work specifically required to benefit the WDBA at an extraordinarily high cost" and "other customers of the Company do not benefit from these capital expenditures" (9T 2980). Mr. Coppola's assertion that relocation costs are "extraordinarily high" is unsupported and contrary to the record, as outlined above. Mr. Bruzzano further explained that customers will benefit from the relocation because they are served by the underground cables that are currently at the site, and reliability would decline if the equipment were not relocated to protect infrastructure integrity. Relocating the infrastructure will also provide easier access for maintenance and repairs in the future, rather than attempting to access infrastructure located under the POE. Therefore, the relocation costs are reasonable and prudent, and the AG's proposed disallowance should be rejected (4T 255-56).

The Company's Investment and Maintenance Plan 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 to recover from interruptions in electric service (*e.g.*, emergent replacements during storms, and equipment failures at substations), to address customer requests for new or upgraded service connections, or to relocate equipment in response to third-party

²⁹ Soil conditions at the site and POE-required pre-loading to avoid excessive settlement after construction would have compromised the manhole and conduit integrity of the Company's infrastructure if it had been left in place (4T 161-62, 254-55).

requests (e.g., MDOT). Details are included in Exhibit A-12, Schedule B5.4, pages 3 to 6, with more detail on Exhibit A-23, Schedule M3 (4T 146-47).

Strategic Capital programs include investments that are necessary to ensure the long-term health of the electric distribution system, and the continuing ability to serve customers with a high level of reliability and power quality, particularly as economic activity continues to rebound in southeast Michigan and as the distribution system continues to evolve in response to higher levels of DER and EV penetration (4T 147). Consistent with the Five-Year Plan and Case No. U-20162, Strategic Capital includes the following three categories, which are further discussed in subsection 3 below:

1. *Infrastructure Resilience and Hardening.* These projects and programs focus on replacing aging infrastructure, hardening the system, and addressing areas with known poor reliability (4T 147). Exhibit A-12, Schedule B5.4, page 7 provides an overview, with additional details at Exhibit A-23, Schedule M4.
2. *Infrastructure Redesign.* These projects and programs include more fundamental changes to the electrical system, such as converting entire substations and circuits to a higher voltage level to serve increased load (4T 147). Exhibit A-12, Schedule B5.4, page 8 provides an overview, with additional details at Exhibit A-23, Schedule M5.
3. *Technology & Automation.* These programs are designed to leverage proven technology solutions that provide significant customer benefits and bring the Company on par with current industry standards. This category also includes various pilot projects to test new technologies and their applications on DTE Electric's system, including non-wires alternatives (NWA). (4T 147-48). Exhibit A-12,

Schedule B5.4, page 9 provides an overview, with additional details at Exhibit A-23, Schedule M6.

Mr. Bruzzano further explained that strategic investment programs are evaluated against seven impact dimensions in the Company's Global Prioritization Model (GPM) (4T 148; Exhibit A-23, Schedule M7). Table 9 at 4T 149 shows the top 44 Strategic Capital investments, excluding "must do" projects and some other projects that are already well underway (4T 148-50).³⁰ This provides a sound basis for the Company's investment decisions, but other key considerations also affect those decisions (*e.g.*, scheduling, coordination, and proactive replacements of assets nearing end of life to avoid equipment failures).

The three key objectives that the Company is pursuing on behalf of its customers are: (1) Reducing Risk; (2) Improving Reliability; and (3) Managing Costs (4T 150-56). Improving safety is the Company's highest priority. The Strategic Capital investments will reduce safety risks by addressing the areas that are most susceptible to downed power lines. Eliminating the risk associated with a major substation failure is also a critical part of reducing risk. Reliability is measured by the all-weather System Average Interruption Duration Index (SAIDI) and by SAIDI-Excluding-Major Event Days (MEDs), with DTE Electric falling in the fourth (worst) quartile for all weather SAIDI in several of the past years. Improving reliability is a key focus for strategic investments and is critical to achieving the Company's goal to operate at the industry average or better for SAIDI (4T 151-53).³¹

³⁰ Tree trimming is the highest priority strategic program, but the costs are O&M, and not capital (4T 148). See section VIII. C. 5 (Distribution Operations O&M Expenses) for a further discussion regarding tree trimming.

³¹ Kroger witness Mr. Bieber asserted that the Company "needs an effective mechanism to incentivize it to improve reliability performance" so he proposed that the Commission establish a Reliability Improvement Mechanism (RIM). (8T 2160). The Company acknowledges its reliability performance as indicated above, but disagrees with the proposed RIM because it is unrelated to the causes of low reliability (mostly trees), and the Company is already under reporting

Strategic Capital investments will also help the Company manage costs because, if they are funded and implemented as proposed, then the Company forecasts that capital required for emergent projects will be reduced compared to what it would have been otherwise (4T 154; Exhibit A-12, Schedule B5.4, page 1, line 6; the reductions in emergent O&M is reflected in Exhibit A-13, Schedule C5.6, page 1, line 19). The present value of the economic benefit to customers from the Strategic capital and tree-trimming investments is estimated to be \$7.1 billion to \$9.5 billion (4T 153; Exhibit A-23, Schedule M8).

Mr. Coppola proposed a 20% (\$182,341,000) disallowance for Strategic Capital (\$78,313,000 for 2019; \$25,301,000 for the four months ending April 2020; and \$78,727,000 for the projected test year), reasoning that the Company's spending commitment is dependent on weather events, so "it is not a commitment at all" (9T 2985). Mr. Bruzzano disagreed, emphasizing the Company's prior investments and commitment to spending the forecasted Strategic Capital. Further, Mr. Coppola's proposal leads to an unreasonable result through "cherry picking" selective data without regard to offsetting considerations.³² The Company's capital expenditures must also be viewed in totality, since the Company has an obligation to allocate its resources in the best interests of its customers based on operational circumstances that are occurring at any given time (4T 257-58).

requirements in connection with its tree-trimming surge program, as discussed below in section VII. C. 5 regarding Distribution Operations O&M expenses. The Company also does not need an incentive to focus on reliability. Instead, the Company already is focused on improving reliability (4T 281-82, 372-73; Exhibit A-23, Schedule M7, pages 2-3). Moreover, Kroger's proposed RIM threatens to penalize the Company for events that are beyond its control, such as weather-related power outages. Therefore, Kroger's proposal to make the Company guarantee the future should be rejected as contrary to law, unfounded in fact, and bad policy.

³² The Michigan Supreme Court cited with approval the conclusions of a circuit court judge granting an injunction against such unlawful rates: "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." *Michigan Consolidated Gas Company v Public Service Comm*, 389 Mich 624, 633; 209 NW2d 210 (1973).

Total year-to-date spending through September 2019 for DO as a whole is over forecast by \$45.7 million. Emergent Replacement spending exceeded the forecast by \$114 million. The Company cannot defer emergent replacements (replacing equipment that is damaged by weather or other circumstances) in favor of Strategic Capital investments. Deferring the work and associated costs would leave customers without power for extended periods of time, leave the system at risk of additional equipment damage and customer outages, or leave equipment in a temporarily-repaired condition that could leave hazards unaddressed (4T 259; Exhibit A-31, Schedule V-1).

Mr. Coppola did not dispute the Company's forecasting methodology (he simply proposed inflation adjustments, which lack merit as discussed above). Using this five-year average, one can expect that Emergent Replacements will at some point swing lower than forecast, in which case the Company would be able to accelerate its Strategic Capital programs (4T 260).

On the other hand, if Mr. Coppola's proposal to disallow 20% of Strategic Capital were to be adopted, then the Company would not be able to implement many projects that are aimed at reducing risk, improving reliability, and managing costs. There would be several negative consequences, including (1) continued degradation of the system and increased equipment failures; (2) difficulty supporting economic development and customer growth, as overloaded circuits would not be addressed (further damaging equipment) and needed capacity would not be added; (3) the system would be less resilient to intense weather events; and (4) the system would not have the infrastructure or the technology to support further penetration of DER and EV. Therefore, Mr. Coppola's proposal should be rejected (4T 154-55, 260-61).

3. Specific Capital Investment Programs

As discussed above, DTE Electric's planned distribution system investments are focused in three areas: 1) Infrastructure Resilience & Hardening, 2) Infrastructure Redesign, and 3) Technology and Automation.

i. Infrastructure Resilience & Hardening

Infrastructure Resilience & Hardening focuses on hardening the system, addressing frequent outage circuits, and replacing aging infrastructure. The Company projects capital expense associated with these projects of \$237.3 million for 16 months ending April 2020, and \$197.5 million for 12 months ending April 2021 (4T 163; Exhibit A-12, Schedule B5.4, page 7; Exhibit A-23, Schedule M4). The Company plans to invest in 25 different programs in this category, however, three specifically warrant particular discussion: (1) 4.8 kV Hardening, (2) Pole and Pole Top Hardware (Pole Top Maintenance), and (3) Cable Replacement.

The 4.8 kV Hardening program was developed to address the aging 4.8 kV system. Primary components of the program include replacing or reinforcing poles as necessary, replacing wooden cross-arms with fiberglass cross-arms, removing Detroit Public Lighting Department (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 (4T 164). DTE Electric is prioritizing the order in which it addresses the different sections of the 4.8 kV system based on numerous criteria, including safety and reliability performance, with safety being the primary driver in the prioritization efforts (4T 165-66). 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). Moreover, the 4.8 kV hardening will deliver safety and reliability improvements faster than 13.2 kV conversion could (4T 284), and circuits are prioritized based on the greatest risk of something happening that could cause an injury (4T 365).³³

The Company's Pole Top Maintenance program proactively identifies and replaces damaged or defective equipment before unexpected failures occur (4T 170). The Company inspects poles on a 10-12 year cycle. Results from these patrols have typically shown that approximately five to seven percent of the total poles inspected have reduced strength and need to be remediated (4T 171). In recent years, the number of poles that are failing in service has increased. To address this trend, the Company has deployed an enhanced pole inspection process and will sustain its significant investments in this program for the foreseeable future (4T 172-73).

The Cable Replacement program prioritizes and replaces system cable based on multiple factors including cable type, vintage, failure history, system impacts, and cable loading. There are approximately 3,100 miles of underground system cable on the Company's distribution and subtransmission systems. The Company is ramping up its cable replacement efforts, which will benefit customers through reduced risk of lengthy outages, as well as lower reactive costs (4T 173-78).

ii. Infrastructure Redesign

Infrastructure Redesign focuses on major projects that generally involve the construction of substations and the rebuilding of large portions of circuits. The Company projects capital expense

³³ Soulardarity witness Mr. Koeppel asserted that the Company is making "inequitable investments in safety and reliability in low-income and people-of-color communities" (6T 1400), and suggested altering the Company's safety and reliability upgrade plan by allocating "more resources in Detroit and other low-income communities and communities of color" (6T 1414). Mr. Bruzzano disagreed. In addition to the discussion above, he explained that the Company's prioritization framework provides the greatest weighting to safety improvements (4T 283; Exhibit A-23, Schedule M7). Also, while approximately 14% of the Company's customers are located in the City of Detroit, the Company is investing more than 25% of its 2019 Strategic Capital in the City of Detroit to address aging infrastructure and improve safety and reliability, and these significant investments will continue in future years (4T 283-84).

associated with these projects of \$117.6 million for 16 months ending April 2020, and \$111.0 million for 12 months ending April 2021 (4T 178; Exhibit A-12 Schedule B5.4, page 8; Exhibit A-23, Schedule M5). Significant programs include Subtransmission Redesign, City of Detroit Infrastructure (CODI), and the 4.8kV Conversion and Consolidation.

DTE Electric's Subtransmission system is operated at a mid-level voltage of 24 kV, 40 kV, or 120 kV, and is used to step down transmission voltage to serve distribution substations. The Subtransmission Redesign program focuses on rebuilding both the overhead and underground portions of the subtransmission system. The program is needed to increase capacity for growing demand in specific areas, and to improve reliability due to aging equipment. Benefits include safety, improved reliability and operability, and increased capacity (4T 179-81).

The CODI program is needed because significant portions of the electrical infrastructure in the City of Detroit were placed in service in the early part of the 20th century. Development in the City of Detroit is stressing this aging infrastructure, and new customer load cannot be served with existing capacity. The Company is focusing on six CODI projects in the next three years, as shown on Table 14 of Mr. Bruzzano's direct testimony (4T 181-83. See Exhibit A-23, Schedule M5 for more detail).

The 4.8 kV Conversion and Consolidation Program is aimed at upgrading the 4.8 kV system to 13.2 kV by building new substations and upgrading circuits to add capacity to serve load. This is a costly and expensive process that the Company expects to occur over several decades. Over the short term, the Company expects conversion and consolidation will be driven primarily by load growth, and that this program will be coordinated with the 4.8kV Hardening program (4T 183-85).

Mr. Koeppel suggested that the Company's investments in areas experiencing load growth will "[o]ver time . . . result in greater inequality of service between low-income and high-income

areas” (6T 1413). Mr. Koepfel appears to have misunderstood DTE Electric’s evidence, and his position neglects that the Company has an obligation to serve all of its customers. Thus, although the Company prioritizes its investments based on safety and reliability, it must also make investments in areas that need additional capacity in order to serve its customers (4T 285-86). Detroit also experienced a unique and dramatic decline in population, and only portions of the City of Detroit are experiencing population or economic growth (4T 348-50).

iii. Technology & Automation

Technology & Automation investments are aimed at deploying technology and communications infrastructure that is needed to operate a modern distribution grid and prepare it for a greater level of DER and EV penetration. The Company projects capital expense associated with these projects of \$163.3 million for 16 months ending April 2020, and \$85.1 million for 12 months ending April 2021 (4T 185; Exhibit A-12 Schedule B5.4, page 9; Exhibit A-23, Schedule M6). Significant investments include the Advanced Distribution Management System (ADMS), System Operating Center (SOC) Modernization, 13.2 kV Telecommunications, Distribution Automation, and Non-Wire Alternatives (NWA).

ADMS is the technology platform that will substantially improve 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 is replacing several systems that are 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). (4T 186-87). 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” (May 2, 2019 Order in Case No. 20162, p 29). Mr. Bruzzano further discussed the benefits of ADMS (4T 188-90) and provided additional information on the three ADMS projects: GMS/EMS (4T 190-92); OMS/DMS (4T 192-95); and NMS (4T 195-96).

Mr. Villareal did not disagree with the Company’s investments but indicated a concern that the Company is not properly testing the interoperability of its ADMS and grid modernization technologies (9T 2706). DTE Electric agrees with and follows the National Institute of Standards and Technology (NIST) definition of “interoperability” (“the capability of two or more networks, systems, devices, applications, or components to work together, and to exchange and readily use information” 9T 2706), but disagrees that third-party testing is necessary to ensure interoperability. DTE Electric and vendor testing confirms compliance, conformance, and integration of all systems. Third-party testing the same system is unnecessary and would not provide additional value. All of Mr. Villareal’s indicated concerns are either unfounded or already being addressed by the Company (4T 278-81, 313-14).

The SOC Modernization project is aimed at replacing the Company’s outdated primary SOC and the smaller, outdated backup SOC by constructing two facilities designed using current industry security, resiliency, and operability standards. The SOC Modernization project is needed to address the outdated facility and technology, space limitations, and limited visibility of telecommunication infrastructure performance. Customers will benefit from reduced risk in the event of a catastrophe and from faster restoration times, particularly during storms (4T 196-99). Expenditures for the project were included in the Company’s last rate case, where the Commission “stresse[d] the need

for and importance of this modernization project for system operations from a reliability and resiliency standpoint” (May 2, 2019 Order in Case No. U-20162, p 30).

As discussed above regarding distribution grid modernization (4T 138-45) and in the EPRI report (Exhibit A-23, Schedule M-9), having robust and secure communications channels is as foundational as having poles and wires to carry electricity. 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 developed in patchwork fashion. The 13.2 kV Telecommunications project is designed to address these communication gaps and to deploy a consistent channel with sufficient and reliable bandwidth to meet the current and growing requirements of a modern electrical system, and to allow the deployment of the appropriate cybersecurity protocols. The Company’s existing fiber ring will be extended strategically from 2019 to 2024 to locations that provide the most benefit. The project’s benefits will include improved reliability and increased cybersecurity (4T 200-202).

DTE Electric’s efforts on Distribution Automation³⁴ have evolved over the years. Today, roughly 28% of general-purpose substations and 23% of the distribution circuits in DTE Electric’s territory have SCADA monitoring and control, which is a foundational element for further distribution automation. Distribution automation is being implemented strategically to maximize customer benefits. The scope of work for 2020 includes full SCADA control and monitoring of one substation, and the installation of one to three loop schemes on 13.2 kV circuits. The scope of work for 2021 is expected to include six substations and 25 circuits (4T 202-205).

³⁴ 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” (4T 86-87).

The electric generation and distribution industry is evolving, as technologies such as energy storage have seen cost declines and could become economic alternatives to traditional distribution investments, particularly when integrated with new demand response (DR) and energy waste reduction (EWR) alternatives. At least for the current time, however, the Company has determined that Non-Wires Alternatives (NWA) are best suited to addressing situations in which circuits or substation equipment is or might become overloaded, or to help delay or offset planned traditional upgrades (4T 206). Mr. Bruzzano described the Company's methodology for developing NWA pilots (4T 206-208), and the Hancock NWA Pilot and the Substation #2 NWA Pilot that the Company is pursuing as part of the EWR, Non-Wire Alternative settlement U-18268, Attachment E (4T 208-209). The Company is also pursuing the O'Shea Park Energy Storage Pilot (which couples battery storage with existing solar generation), and the Mobile Battery Storage Trailer Pilot (which involves a mobile battery system that could be used to provide load support). (4T 209-10).

4. Contribution in Aid of Construction (CIAC)

DTE Electric's current CIAC policy provides a DTE Electric contribution towards customer line extensions based on 2 times total revenue. MEC/NRDC/SC/CUB witness Mr. Jester proposed "CIAC reform" that would "establish that DTE Electric's maximum contribution to distribution system extensions and connections will be 4.5 times the estimated annual distribution revenue from the customer" (9T 3820).

Mr. Bloch explained that Mr. Jester's proposal should be rejected for three reasons. First, it would create a disincentive for new customers looking to locate in DTE Electric's service territory at a time when DTE Electric's growth rate is low. New customers contribute to fixed expenses, thereby lowering costs for other customers. Second, it does not properly recognize the total incremental value (contribution) provided by new customer load. Third, it would move away from

a long-standing policy and value proposition that existing customers have received, but new customers would not receive (8T 2293).

Mr. Jester suggested that current CIAC policies are inappropriate based on the claim that they “predate unbundled ratemaking” (9T 3816). The suggestion neglects that subsequent to unbundled rates, the Commission approved a standard allowance table that is based on both production and distribution contributions provided by new load, and which provides transparency and consistency (October 31, 2012 Order in Case No. U-17005). Mr. Jester’s proposal is contrary to the Commission’s objectives of providing customers with transparency in determining upfront construction costs, and using a standardized approach between utilities (8T 2293-94).

Mr. Jester further asserted that “Company contributions based on total revenue are likely to cause subsidies by those rate classes with a high ratio of distribution revenue to total revenue (i.e., residential and commercial secondary customers) to those rate classes with a low ratio of distribution revenue to total revenue” (9T 3816). Mr. Bloch disagreed, noting that Mr. Jester offered no explanation or support for his assertion, and explaining that lower-voltage (residential and commercial secondary) customers use more of the Company’s distribution system, so they are appropriately allocated more distribution system costs than higher-voltage customers. There is no basis for Mr. Jester’s suggestion about alleged subsidies (8T 2295).

F. Advanced Metering Infrastructure (AMI)

DTE Electric is nearing the end of the process of installing Advanced Metering Infrastructure (AMI) meters (also known as smart meters) to increase reliability, reduce outage time, and provide other benefits as compared to obsolete electromechanical (analog) meters. AMI meters are automatically read, monitored and controlled, instead of relying on manual actions (such as meter readers). 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).

The Commission previously found that a “full cost/benefit analysis is no longer necessary,” but ordered the continuing provision of annualized benefit projections in future rate cases (April 18, 2018 Order in Case No. U-18255, p 84). Accordingly, Company witness Ms. Robinson provided a brief background on AMI efforts at DTE Electric (9T 2613-14), explained the benefits to utility customers (9T 2614-18), supported capital investments for AMI technology enhancements including the AMI 3G to 4G³⁵ communication upgrade (9T 2619-24), and provided an update on the Company’s opt-out program, including the digital meter replacement program pursuant to the settlement in Case No. U-20084 (9T 2624-25).

As of April 1, 2019, the Company had installed over 2.6 million electric meters, 648,000 AMI gas modules, and nearly 578,000 Advanced Meter Reading (AMR) gas only modules for a total of nearly 3.8 million endpoints, or nearly 100% of planned meters.³⁶ Customer-related

³⁵ 3G is the third generation of cellular telecommunications technology, which is being succeeded by 4G (and by 5G in some instances).

³⁶ Gas meters relate to DTE Gas and are mentioned for purposes of clarity and completeness, but they are not directly relevant in this electric rate case nor are the costs associated with the gas modules included in the AMI costs DTE Electric seeks to recover in the rates set in this proceeding.

issues (such as locked gates, blocked access to meters, or dogs in the yard) have delayed completion, but the Company was working to complete the remaining 631 installations of AMI electric meters by the end of 2019 (9T 2613-14). At the time of the hearing, the Company still had to install approximately 105 meters at particularly difficult locations (9T 2646).

AMI's major customer benefits are: (1) Meter reading (automation of meter reading provides daily and on-demand, accurate meter reads of each customer meter regardless of energy type, reduces meter reading costs by eliminating the need to gain access for inside meter reads, and enhances the customer experience with the ability to provide daily reads and combine multiple sites onto one bill, and readily start and stop billing without the need for costly field visits); (2) Bill accuracy (customers benefit from the near elimination of estimated bills, and are billed for actual usage); (3) Theft and tampering notice (the system notes tampering at the meter any time it occurs); (4) OSHA recordable injury rate (customers and employees benefit from increased safety through the decreased risk of injuries from slips and falls, and dog bites); (5) Turn on / Turn off / Restore (customer service is improved significantly because DTE Electric can reconnect customers remotely, speeding reconnections); and (6) Outage efficiency (the overall outage operation is enhanced tremendously through the system's ability to report customer outages and restorations, which is particularly important after a storm, where AMI has the ability to "ping" meters to determine their power condition following the restoration of a circuit problem) (9T 2614-16).

New ideas that will enhance customer benefits and improve service quality include: (1) Power quality (AMI's ability to record instances of voltage problems at customer locations enhances the electric infrastructure's engineering design process); (2) Daily storm and non-storm statistics (AMI improves the accuracy of outage data, which improves the overall storm modeling and restoration process); (3) Tree trim program enhancement (AMI data indirectly enhances the

tree trim maintenance program, and will be combined with other data in the future to create predictive maintenance algorithms); (4) Enhanced automated storm job closures (auto-close algorithms avoid numerous “ok on arrival” truck rolls, and shorten the follow-up truck rolls required after an outage); (5) Enhanced storm information (during large storms with over 100,000 customer outages, the AMI system is repurposed to perform similar to an electric distribution management system); and (6) Electric grid phase modeling (DTE Electric is collecting average voltage samples to create voltage signatures of the quality of electric service at the customer site, and exploring the use of the data to improve the accuracy of the electric network and for enhanced future grid management). 9T 2616-18).

Exhibit A-19, Schedule I1 reflects AMI benefits by year through 2030 and is similar to AMI exhibits that the Company has provided in the past, except that it does not include future costs or a net present value requirement, since the Commission ruled that a full cost/benefit analysis is no longer necessary (April 18, 2018 Order in Case No. U-18255, p 84). The Company proposes to discontinue AMI reporting in future rate cases. With the AMI installation nearly complete, most of AMI’s initial benefits are already realized. The Company also provides annual smart grid reports to the Commission and meets with Staff monthly (9T 2618).

Staff instead “recommends the actual yearly realized benefits of AMI be provided for the same categories in Exhibit A-19, Schedule I1 from installation through the rate case. Staff also recommends the Company provide the forecasted benefits for past years, as well as future projections, to allow a comparison of forecasted benefits with actual realized benefits. This data should be collected for the life of the AMI installations” (9T 3362).

The Company disagrees. In addition to the discussion above, Ms. Robinson explained that the amount of data being requested by Staff would require a full-time employee to build a model,

mine the data, and continue to report the data going forward, with no real benefit. The effort is not justified, since AMI is here to stay, Staff and the Company agree that AMI has numerous benefits, and the Company is actively seeking new ways to leverage its investment (9T 2629). Thus, Staff's proposal to continue to include AMI benefit information in future rate cases should be rejected.

Ms. Robinson supported capital investments for AMI technology enhancements including capital spending required in new AMI infrastructure due to public cellular wireless carriers phasing out of 3G cellular by 2020 (Exhibit A-12, Schedule B5.4, page 9, lines 6 and 7); capital spending required to complete AMI installations requiring special skills, appointments, or hard-to-access customers (*Id*, line 8); and capital spending on the AMI Analytics project that was completed in 2018 (*Id*, line 9). Additional detailed project information is included in Exhibit A-23, Schedule M6, pages 11-18 (9T 2619).

The Commission previously approved 2018 spending of \$2,335,000 for the AMI Mesh Network Project to upgrade the AMI network from 3G technology to either 4G technology or DTE Electric's private mesh network. The Commission suggested that the Company provide additional evidence and stated: "Depending on the actual rollout schedule for 5G, the Commission notes that there may be the potential to move from 3G to 5G in certain areas, rather than investing large amounts in 4G when it, too, could soon be obsolete" (Case No. U-18255, April 18, 2018 Order, p 13). Accordingly, Ms. Robinson reiterated that the cellular industry is moving away from 3G technology, which will soon be obsolete. DTE Electric must similarly upgrade its technology. DTE Electric has approximately 3,000 cellular 3G Cell Relays (CR's) and 6,000 3G cellular industrial customer meters. They all must be replaced prior to Q4, 2020, or DTE Electric will lose daily communication with approximately 1 million of its 2.6 million residential electric meters and all 6,000 industrial meters. That would cause the AMI meters to lose remote functionality (*e.g.*, for

billing, outage information, and disconnect/reconnect capabilities), and the AMI benefits discussed above would be lost. The 3G to 4G upgrade will avoid these losses and will also provide additional customer benefits through better connectivity to meters, as well as create a communication foundation for other devices to utilize. The Company also plans to add an additional 300 relays as a second Optimization wave to strengthen its communication network (9T 2619-22), as further discussed below.

DTE Electric and its equipment vendors properly focused on the replacement strategy since 2016, but could not transition to 4G faster due to the time needed for product development and FCC approval. Products were not commercially available until late 2018 (9T 2621-22). Regarding the Commission's suggestion that there may be potential to avoid costs by moving to 5G rather than investing in 4G, Ms. Robinson testified that 5G products are not available, but 4G products have been designed for continuing use with future technology improvements:

At present, manufacturers of AMI equipment are not designing 5G products and 5G infrastructure is not readily available. The Company has, however, worked with multiple manufacturers of AMI equipment to minimize the impact as the cellular industry upgrades technology beyond 4G cellular. For instance, the cellular component of the existing CR is an integrated component of the CR. The new design is such that the cellular card is designed as removable from the device, establishing the possibility of upgrading the cellular card while the rest of the device remains for an extended service life. At this time, cellular providers have stated that 4G will be compatible with 5G. The Company's engineering team added a network card to each relay that will allow us communication path flexibility in the future and another pathway independent of cellular (9T 2622).

The Optimization phase is to install an additional 300 cellular relays to strengthen the Company's mesh network (9T 2620). Staff proposed a complete (\$2 million) disallowance, noting that the Commission previously disallowed a similar proposal (May 2, 2019 Order in Case U-20162, pp 34-35), and reasoning that it is unnecessary to increase the Company's meter read rate because it is well above the Commission's Service Quality and Reliability Standard of 85% (9T 3363-64).

Ms. Robinson explained that the 85% performance level was set before the deployment of AMI infrastructure. That performance level is clearly untenable and would drastically undermine core benefits of an AMI system. A read rate of only 85% would result in approximately 285,000 estimated bills each month. It is important to have a high read rate because customers want to be billed for their actual usage. Increasing the read rate would reduce estimated bills, and thereby result in fewer customer complaints. Staff also appears to have a fundamental misunderstanding about the necessity of the 3G to 4G project's Optimization phase. The main purpose of strengthening the communications network is to *sustain* read rates, not *improve* them. From May through October, seasonal vegetation impacts remote meter reading to approximately 13,000 meters, due primarily to leaves blocking the radio signals from the AMI meters. This results in estimated bills, unless the Company engages in manual meter reading efforts, which involve expenses and generates additional customer complaints. Therefore, the cost to strengthen the network by addressing pockets of meters affected by vegetation is prudent for the Company and useful to customers (9T 2631-32, 2638).

Staff also proposed to disallow \$4,450,000 associated with installing Power Quality (PQ) meters at 950 locations under the C&I 3G to 4G project, reasoning that the site selection (based on load of about 1 MW and above) appeared to be arbitrary and not based on demonstrated need (9T 3364-65). Ms. Robinson disagreed, explaining that Staff's proposed disallowance appears to be based on the inaccurate premise that PQ meters are useful only as a forensics tool to aid in root cause analysis after an electrical disturbance has occurred at a site. The Company believes that it is prudent to invest in PQ meters for top-load customers to reduce the impact and/or damage to circuit or customer equipment when disturbances occur. Due to the 1 MW load scale at the selected sites, it is crucial to detect disturbances immediately and to have relevant data available to inform

Company and/or customer personnel to initiate the most appropriate responses. Therefore, PQ meters must generally be in service before an electrical disturbance occurs. This is also the appropriate time to make this investment because the existing 3G meters must be replaced as obsolete. Therefore, the full investment should be allowed. Alternatively (but not optimally), at least \$1,358,500 should be allowed to cover the costs of replacing 3G meters with “non-PQ” 4G meters (9T 2633-34).

The Commission approved the Company’s AMI opt-out program in its May 15, 2013 Order in Case No. U-17053, and the Court of Appeals affirmed. *In re Application of Detroit Edison Co to implement opt-out program*, unpublished opinion per curiam of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728 and 316781). As of January 1, 2019, the Company had approximately 7,600 customer sites and 9,400 customer meters that opted out. At this rate, and based on the relatively-few hard-to-reach customers remaining to be converted to AMI, there would be less than 8,000 customer sites opting out when AMI installation is complete, which is considerably less than the 15,500 customers anticipated in Case No. U-17053. DTE Electric does not propose any changes to the opt-out charges in this case. DTE Electric anticipates completing its AMI installations and will then file an application in accordance with the Commission’s directive that “within six months after completion of its AMI installation, DTE Electric shall file, in a separate docket, an application for review of the opt-out charges” (January 31, 2017 Order in Case No. U-18014, p 129). Pursuant to the settlement agreement in Case No. U-20084, the Company has also conducted a program (which is nearing its conclusion) to replace the meters of existing AMI opt-out customers and any customers who want to opt-out but have not had an AMI meter installed, with digital meters without radios (9T 2624-25, 2645).

RCG witness Crandall re-asserted RCG's anti-AMI arguments, including that DTE Electric should have updated its AMI opt-out charges in the pending case, and that they should be eliminated (9T 2816-23). RCG's position remains meritless and again should be rejected. As indicated above, the Commission approved DTE Electric's AMI opt-out program in its May 15, 2013 Order in Case No. U-17053. The Court of Appeals affirmed, and our Supreme Court declined to review that case. In Case No. U-18014 (quoted above regarding when DTE Electric is to revisit the opt-out charge issue), the PFD concluded: "Based on the testimony and exhibits in the record, the PFD recommends that the Commission accept DTE's and Staff's view that it is premature to revise the opt-out charges, and instead that the Commission require DTE to file a separate application for review of those charges within 6 months of completing the AMI meter installations" (U-18014 PFD, p 308). The Commission agreed with the PFD, relevantly stating:

The Commission finds the ALJ's recommendation persuasive. Because DTE Electric has yet to complete its AMI installation, the Commission agrees with the company, the Staff, and the ALJ that it is premature to review and amend the opt-out charges. . . .

In response to the RCG's claims that the current-opt out charges should be eliminated or sharply reduced, that the tariff should require customer consent before an AMI meter may be installed, and that installation of an AMI meter infringes upon a customer's privacy, health and safety, and constitutional rights, the Commission finds that these arguments have been fully reviewed and addressed in previous cases and that the RCG provided no new evidence or analysis that persuades the Commission to revisit these issues. *See*, May 15 order [in Case No. U-17053], pp. 17-18, *aff'd*, *In re Application of Detroit Edison Co to Implement Opt Out Program*, unpublished opinion per curiam of the Court of Appeals, issued February 19, 2015 (Docket No. 316728), p. 9; December 11 order [in Case U-17767], pp. 97-99. [January 31 Order in Case No. U-18014, p 129.]³⁷

The Court of Appeals affirmed, and our Supreme Court declined to review the case, rejecting the same argument that RCG attempts to raise again here. *In re Application of DTE*

³⁷ RCG filed a petition for rehearing, which the Commission denied because RCG simply repeated arguments that had repeatedly been rejected (April 13, 2017 Order on Rehearing in Case U-18014, pp 3-4).

Electric Company to Increase Rates, unpublished opinion per curiam of the Court of Appeals, issued October 25, 2018 (Docket No. 338378), *lv denied* 931 NW2d 334 (2019), *reconsideration denied* 935 NW2d 346 (November 26, 2019). The Court of Appeals extensively recounted prior proceedings beginning with Case No. U-17053 (Opinion, pp 5-7) and then explained:

In this appeal, Residential again argues that the opt-out charges should be eliminated. Residential first contends that there was no evidence presented in the current proceeding supporting the amount of the fees. The reason for this was simple: DTE was not seeking to alter the opt-out fees, which had been set in Case No. U-17053. As the MPSC has explained previously, there is no need for the MPSC to take new evidence on an issue that has been decided previously, absent a showing that circumstances have somehow changed. [Opinion, p 7, following *In re Consumers Energy Co App*, 322 Mich App 480, 493-94; 913 NW2d 406 (2017) and *Pennwalt Corp v Public Service Comm*, 166 Mich App 1, 9; 420 NW2d 156 (1988).]

The Commission again followed the well-established law and its own recent decisions in rejecting RCG's repeated arguments in Case Nos. U-18255 and U-20162 (April 18, 2018 Order in Case No. U-18255, p 85, and May 2, 2019 Order in Case No. U-20162, pp 36-37). In accordance with the Commission's decision in Case No. U-18014 (relevantly quoted above), the Company anticipates filing an application for review of the opt-out charges in a separate docket before the end of the third quarter of 2020 (9T 2635).

Accordingly, RCG's AMI arguments should again be rejected.

G. Community Lighting

Mr. Bellini supported DTE Electric's Community Lighting capital expenditures for 2018 through the projected period ending April 30, 2021 (9T 3478). Capital spending for Community Lighting (detailed on Exhibit A-12, Schedule B5.5) was \$14.0 million in 2018, and is expected to be approximately \$12.5 million for 2019, \$4.1 million for the 4 months ending April 30, 2020, and \$14.2 million for the 12 months ending April 30, 2021 (9T 3488-89). There is no disagreement on this topic.

H. Demand Response (DR) Programs

DTE Electric plans \$8.5 million of capital expenditures for its Demand Response (DR) portfolio for the projected test year ending April 30, 2021, consisting of Interruptible Air Conditioning (IAC) (\$2.8 million), Other DR Pilots (\$4.1 million), and DTE Insight (\$1.6 million). (9T 3516; Exhibit A-12, Schedule B-5.6, column (f)). DTE Electric spent \$10.1 million in 2018, and plans to spend \$14.5 million in 2019, and \$2.0 million in the 4-month period ending April 30, 2020 (Exhibit A-12, Schedule B-5.6, columns (b), (c), and (d)). Mr. Cejas Goyanes described the importance of developing DR programs (9T 3512-13) and provided an overview of DTE Electric's DR portfolio (9T 3513-15; Exhibit A-30, Schedule U-1).

The IAC program was first approved in the December 11, 2015 Order in Case No. U-17767, pp 35-36). The Company is accelerating its efforts and intends to replace all the old IAC switches with new Load Control Devices (LCDs) by 2023, translating into a total of 244 MW of MISO-acknowledged nameplate capacity for DTE Electric. DTE Electric is forecasting to spend \$8.4 million during the bridge period of January 2019 through April 2020, and \$2.8 million for the projected test year period ending April 30, 2021 for the IAC program (9T 3517-20; Exhibit A-12, Schedule B5.6, page 1 of 2, line 1, columns (e) and (f)).

The Programmable Controllable Thermostat (PCT) pilot is available to residential customers and requires customers to enroll in the Dynamic Peak Pricing (DPP) tariff (D1.8 rate). The customer's enrollment allows the Company to send a pricing signal to a PCT installed in the customer's home that raises the thermostat by 4 degrees during a DPP event. The customer retains the option to override the temperature set point. The purpose of the program is to lower peak-hour electric consumption by residential customers (9T 3520-21).

The Commission previously agreed with Staff's proposal to limit DTE Electric to 10,000 PCTs, noting that "[i]f DTE Electric demonstrates that its DR programs are successful in the initial phases, additional DR expenditures will be recoverable in a subsequent rate case" (January 31, 2017 Order in Case No. U-18014, p 25). In the Company's next general rate case, the Commission disallowed the Company's request for funding to purchase additional PCTs, stating that the "Commission agrees with the utility that complete installation was not necessary to support increased funding, but a showing of initial success was" (April 18, 2018 Order in Case No. U-18255, p 22). Most recently, the Commission denied incremental funding to enroll the original 10,000 customers, as well as the Company's additional funding request to support additional enrollment, stating that it "will not consider further expenditure until DTE Electric completes enrollment of the first 10,000 customers and demonstrates some measure of success with the program (May 2, 2019 Order in Case No. U-20162, pp 38-39).

Mr. Cejas Goyanes testified that the Company had enrolled 6,330 customers on PCTs as of June 15, 2019 and expected to complete the enrollment of 10,000 units by the end of 2019. This enrollment volume illustrates the Company's progress in implementing the initial phases of the PCT pilot program. The PCT pilot also showed success through PCT customers participating in four events that the Company called during the summer of 2018, with a meaningful decline in electricity usage (an average of 1.0 kW per participating customer) in the critical hours of the events. The Company does not request additional funding for the test year; however, the capital costs that the Company has incurred to date, and the \$3.4 million that the Company expects to incur through the end of the bridge period (January 1, 2019 through April 30, 2020) are used and useful for the provision of utility service (or will be by the test year) and are necessary for the success of the PTC pilot program at the enrollment level authorized by the Commission (9T 3522-27, 3543-44).

Mr. Cejas Goyanes also discussed the Bring Your Own Device (BYOD) pilot (9T 3527-29) and other on-going or future DR pilots (9T 3529-33, 3544-45). These include a behind-the-meter project combining a battery-based energy storage system (BESS) along with a solar photovoltaic (PV) system at an industrial customer site. Other pilot opportunities involving battery storage include the use of a Non-Wires Alternatives (NWA) approach (9T 3531-32). Mr. Bruzzano further discussed potential NWA pilots (4T 206-10). DTE Electric is forecasting to spend \$3.7 million during the bridge period of January 2019 through April 2020, and \$4.1 million for the projected test year period ending April 30, 2021 for these Other DR pilots (9T 3533; Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, columns (e) and (f)).

The DTE Insight program centers on a mobile application that is integrated with AMI and helps 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. With the EB's recently-expanded functionality, users can also control other connected smart devices such as thermostats. In 2018, DTE Insight participants saved 30,821 MCF of natural gas, 9,544 MWh of electricity, and 2.74 MW of coincident peak demand. The Company recently transitioned the program onto a more robust platform that includes an updated Insight app with an improved EB. The Company also developed a customer charge for the EB devices. The Company plans to continue improving the program and might experiment with various pricing models. The Company plans to manage the existing EB inventory (53,708 as of June 10, 2019) to fulfill ongoing EB requests expected for 2019 and 2020, and estimates that it will purchase approximately 20,000 EBs in 2021. DTE Electric is forecasting to spend \$1.1 million during the bridge period of January 2019 through April 2020 and \$1.6 million for the projected test year period ending April 30, 2021 (9T 3534-38, 3546-47; Exhibit A-12, Schedule B5.6, page 1 of 2, line 4, column (e) and (f)).

Staff recommended a \$1.622 million increase in present revenue based on incorporating EB fees in other miscellaneous revenue (9T 3114-16; Exhibit S-6, Schedule C3, page 3). Mr. Cejas Goyanes explained that Staff made two miscalculations, First, Staff used a \$1.99 per month charge that is actually two charges that are accounted for in separate places (\$0.99 offsets EB costs and is included in other operating revenue (and is the only charge Staff should have used); \$1.00 offsets costs associated with customer use of the DTE Insight app , and is included in the Energy Waste Reduction (EWR) program). Second, Staff inaccurately based its customer count on EBs in the field at the end of the test year, without considering that new customer enrollment will occur throughout the year, and fees are not charged until after a six-month trial period. Therefore, the increase in present revenue that should be incorporated into other present revenue is \$0.527 million rather than \$1.622 million (9T 3555-57; Exhibit A-37, Schedule BB1).

ABATE witness Ms. Alderson asserted that “DTE’s requested capital expenditures for DR programs differ materially from those requested just three months prior in DTE’s Integrated Resource Plan (‘IRP’) in Case No. U-20471,” and suggested that the Company address this matter in its rebuttal (7T 1803). Mr. Cejas Goyanes responded by explaining that the Company’s proposed DR capital expenditures are just and reasonable considering the three-phase approach for DR cost recovery that the Commission approved in Case No. U-18369. That approach essentially contemplates that DR plans would be initially approved in the IRP, and then effectively incorporated into rates in the subsequent rate case. Here, however, DTE’s Electric’s IRP case was pending when the Company filed its rate case, so there was no IRP-approved DR plan preceding this Case No. U-20561 (9T 3542-43). The Company’s request for DR capital expenditures is also just and reasonable on its own merit, regardless of the existence of IRP pre-approval. The Company’s updated request is based on changes in circumstances and new pilot opportunities

between the IRP filing and the filing of this Case No. U-20561 (9T 3543). Mr. Cejas Goyanes further explained the differences in the updated PCT and Other DR pilots (9T 3521-34, 3543-44).

Ms. Alderson similarly asserted that the “DTE Insight program capital expenditures should be denied in the instant proceeding as they have not been evaluated in the context of the full IRP” (7T 1804). Mr. Cejas Goyanes disagreed based on the merits of the program and the Commission’s prior support for it (as outlined above), and further explained that the program is designed to reduce electricity demand. The Company does not measure the potential reduced electricity demand as a metric of a supply resource for capacity purposes. Since the program was not implemented to meet MISO requirements as a load modifying resource (LMR), it was not included in the IRP planning (9T 3547-48).

Ms. Alderson further asserted that: “In DTE’s pending 2017-2018 DR Reconciliation proceeding in Case No. U-20521, DTE requests approval of a Financial Incentive Mechanism to provide an incentive for investing in DR programs . . . DTE should be prohibited a return on its Test Year capital amounts for DR programs if the Commission approves of an incentive in Case No. U-20521” (7T 1804). Mr. Cejas Goyanes explained that Case No. U-20521 is ongoing and no party, including the Company, has filed a specific proposal for consideration of a financial incentive mechanism. Therefore, ABATE’s proposed disallowance based on a hypothetical and undefined financial incentive mechanism should be rejected as speculative (9T 3549).³⁸

Staff supported the Company’s proposed recovery for the BYOD pilot and the Electric Power Research Institute Transportation Program pilot (EPRI pilot), but recommended that “the Commission not approve capital costs associated with potential future DR pilots that are only in the exploratory stage” (9T 3136). Staff explained that it took essentially the same position in the

³⁸ DTE Electric reserves all rights to further address this issue in this and/or other cases.

Company's IRP case (Case No. U-20471) and re-asserted its reasoning that the "three-phase DR framework give[s] the Company ample opportunity to propose new DR capital spending on other pilots at a later time when it can be determined that those pilots actually have a defined purpose" (9T 3136-37).

Mr. Cejas Goyanes disagreed with Staff's proposed disallowance, emphasizing the importance of pilots in identifying how the Company's unique customer base will react to specific marketing efforts, program design features, and other characteristics that are dependent on DTE Electric's unique combination of systems, equipment, tariffs, programs and processes (9T 3550-52).

Staff's suggestion that there are other opportunities for cost recovery under the three-phase DR framework also neglects the timing involved. If the additional pilot spending is not preapproved in this case beyond the BYOD and EPRI pilots, then the development and execution of new DR programs could be delayed by several years. Under Staff's proposal, the Company's next opportunity to request DR pilot spending would be in its next general rate case (perhaps the summer of 2020, after the Commission decides the current rate case, No. U-20561), so an order approving the pilots could be issued around May of 2021, at the earliest. Then it would likely take another year to get the pilots up and running, delaying results until the summer of 2023. Only then, after this serious delay, would there be any potential to leverage any learnings into a full program (9T 3553).

To address Staff's concerns about pilots that are not fully defined, DTE Electric proposes to meet with Staff periodically to address the Company's pilot initiatives and progress. If there are any remaining concerns after the Company's explanation and the Staff's feedback, then they could be expressed in the annual DR reconciliation proceedings. The extra oversight through

collaboration and guidance by Staff would appropriately address Staff's concerns, without delays and potential missed opportunities that are inherent in Staff's proposed cost disallowance (9T 3554).

I. Information Technology

DTE Electric's Information Technology (IT) Department delivers services and solutions that are designed to be secure, reliable, and maintainable, while providing business value and a positive customer experience (8T 2358). Capital projects and investments are generally grouped into three categories: (1) IT Asset Health, (2) Value Creation, and (3) Non-Discretionary (8T 2358-60; Exhibit A-12, Schedule B.5.7 lines 12-14). There are also some projects that are less than \$250,000, which are small but nevertheless necessary (Exhibit A-12, Schedule B5.7.1, line 15). Total IT capital spending was \$79.2 million in the 2018 historical test year and is projected to be \$133.4 million for the 16-month period ending April 30, 2020, and \$136.7 million for the 12-month test year ending April 30, 2021 (8T 2357, 2371; Exhibit A-12, Schedule B5.7, line 45, columns (b), (e), and (f)).

DTE Electric has a robust IT capital planning process, which is known as the Annual Planning Cycle (APC), with output from that process included in this case. Exhibit A-12, Schedules B5.7.1 through B5.7.8 provide a high-level view of all projects/initiatives supported in Mr. Griffin's testimony. The Business Cases Exhibit (Exhibit A-24, Schedule N1) provides executive summaries for those projects with capital expenses over \$500,000, as the Commission directed (May 2, 2019 Order in Case No. U-20162, pp 43-45). The detailed business cases are provided as workpapers (8T 2360-62).

Mr. Griffin provided an overview of the most significant investments in each of the eight IT capital portfolios listed on Exhibit A-12, Schedule B5.7, lines 2-9, organized into the categories

of Asset Health, Value Creation, Non-Discretionary, and less than \$250,000 as indicated above. In summary:

1. The Corporate Applications Portfolio consists of the business systems that are used by the Company (Payroll, Timekeeping, Financials, Document Storage, Compensation, Supply Chain) or that support common corporate processes (Safety, Employee Wellness, Communications, Training). (8T 2363-71; Exhibit A-12, Schedule B5.7.1);
2. The Customer Service Portfolio consists of key systems integrating with the Company's SAP Customer Relationship and Billing (CR&B) platform (8T 2372-87; Exhibit A-12, Schedule B5.7.2);
3. The Plant and Field Portfolio consists of the business systems that are used by the Distribution, Fossil Generation, Generation Optimization, and Fermi organizations (8T 2387-94; Exhibit A-12, Schedule B5.7.3);
4. The Information Technology for IT Portfolio is responsible for 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 (8T 2394-2406; Exhibit A-12, Schedule 5.7.4);
5. The Technology & Architecture Portfolio has traditionally focused on enterprise data architecture planning and instrumentation, and rapid solution design. These initiatives ensure that the Company is well positioned to take advantage of long-term technology road mapping and to react to emerging technology opportunities (8T 2406-2409; Exhibit A-12, Schedule B5.7.5);

6. The Information Protection & Security Portfolio is focused on reliability of security infrastructure and improving the Company's security posture (8T 2409-13; Exhibit A-12, Schedule B5.7.6);
7. The Infrastructure Operations Portfolio is responsible for the design, implementation, and secure operation of the Company's overall IT infrastructure (8T 2413-24; Exhibit A-12, Schedule B5.7.7); and
8. The Enterprise Data & Analytics (EDA) Portfolio concerns the Company's construction of a cloud-based platform to enable the use of 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 is creating a team to organize, describe, and document the data available on the platform. This team and the system are referred to as Enterprise Data & Analytics (ED&A). (8T 2424-28; Exhibit A-12, Schedule B5.7.8).

Mr. Griffin further explained that in addition to the Commission's requirement for additional basic data on new investments (which the Company has provided as indicated above), there is also a requirement that the Company address the cost variance for capital investments greater than \$0.5 million, approved in the prior year's rate case, where there is more than a 20% variance from the projected budget and for which the Company is seeking additional recovery. To comply with the requirement, Mr. Griffin sponsored Exhibit A-24, Schedule N2, and explained the projects in his testimony (8T 2429).

In Case No. U-20162, the Company projected \$72.5 million of capital investment in IT systems for 2018. The Commission approved \$70.5 million for inclusion in rate base. The Company's actual 2018 capital investment was \$79.2 million. Mr. Griffin addressed the overall

\$8.6 million variance between approved and actual spending by identifying the portion of the variance that occurred in each portfolio and explaining the major factors that contributed to the variance (8T 2430-32; Exhibit A-12, Schedule N2, page 1).

Mr. Griffin then discussed the projects where there is more than a 20% variance from the projected budget and for which the Company is seeking additional recovery. He also discussed additional investments greater than \$0.5 million that were made in the period and demonstrated why those investments were prudent. His discussion is organized by portfolio, as follows: Corporate Applications (8T 2433-35; Exhibit A-24, Schedule N2, page 2); Customer Service (8T 2435-44; Exhibit A-24, Schedule N2, page 3); Plant and Field (8T 2444-47; Exhibit A-24, Schedule N2, page 4); Information technology for IT Variance (8T 2447-49; Exhibit A-24, Schedule N2, page 5); Information Protection Security Projects (8T 2449-50; Exhibit A-24, Schedule N2, page 6); and Infrastructure Operations (8T 2451-55; Exhibit A-24, Schedule N2, page 7).

Mr. Griffin further explained that the Company's filing in Case No. U-20162 included \$2 million to support a deliberate investment in Technical Innovation, which was listed at that time as 2018 Emergent. Staff requested a partial disallowance, asserting that the investments were speculative. As a result, the Commission approved only \$0.57 million for inclusion in rate base (8T 2455-56; May 2, 2019 Order in Case No. U-20162, p 43). The Company actually spent \$4 million (\$3.4 million more than was approved) on this project, which involved the rapid development of Company solutions and pilot testing for the use of emergent technologies. Mr. Griffin described the project's various initiatives, and supported the necessity, reasonableness and prudence of these IT capital expenditures (8T 2456-60).

1. Purchase to Pay (P2P)

AG witness Mr. Coppola proposes a \$5.1 million disallowance for the Purchase to Pay (P2P or Ariba) project, claiming that it was not clear how inventory procurement and scheduling would improve the customer experience, no financial benefits or cost savings were identified, and the project seemed premature (9T 3004-3008).

Mr. Griffin responded by recounting and further explaining that P2P is very important because it will allow the Company to better monitor and control inventory, procurement, and vendor contract performance to ensure that the Company is getting the most value for its expenditure while reducing vendor onboarding overhead. P2P is part of an integrated suite of systems that support the Enterprise Resource Planning (ERP) System, which will be replaced with a cloud-based version of that platform, known as S/4, in 2025. This must be done because the version of ERP that the Company uses will no longer have vendor support (8T 2368-69, 2464-66, 2533-34; Exhibit A-24, Schedule N1.10).

Mr. Griffin further clarified two aspects of IT obsolescence: (1) when a vendor stops making any improvements to a product; and (2) when a vendor stops all support for the product. Regarding the matters included in this case for preparing for S/4, such as P2P and the SuccessFactors project (discussed below), the vendor has already stopped making any new improvements other than software security patches. So DTE Electric is already at the point of being unable to get any additional functionality out of the system (8T 2538). Mr. Griffin further testified:

In 2025, that system goes fully unsupported. In other words, we wouldn't be able to engage the company for technical support, we couldn't get security patches any longer, software patches, upgrades, none of those things would be available any longer. We need to make the move away from that software before it [be]comes unsupported and we're left to our own devices. [8T 2538-39.]

Thus, the P2P project is not premature, and Mr. Coppola's suggestion to delay the foundational work until 2025 is neither feasible nor prudent. Instead, the Company must undertake

numerous steps to make the switch to S/4 by 2025. Implementing Ariba during the 2019 to 2021 timeframe is next in the sequence of foundational upgrades. Moreover, work began in 2018, and the Commission approved \$1.9 million for the initial phase of the Ariba conversion in Case No. U-20162. The Company is now mid-way through implementation. Cancelling the project now would wipe out the value of that investment (8T 2464-65, 2491).

Mr. Coppola's focus on financial benefits or cost savings also neglects that not every investment is driven by these elements. The Company must replace infrastructure from time to time in order to continue delivering safe, reliable and affordable service. In U-17767, the Commission found that "in the interest of providing customers with safe, reliable, punctual, and quality service, the Commission finds it reasonable to provide DTE Electric with sufficient funds to update its software to prevent it from becoming obsolete." (MPSC Case No. U-17767, Order dated December 11, 2015, p130.)

The Company is appropriately replacing at-risk outdated and unsupported software with newer better software to ensure the security of its platforms and operability of its inventory, procurement and vendor services. The customer experience will improve because timely investment in the Ariba platform will improve the timeliness, cost and quality of services provided to customers. Therefore, Mr. Coppola's proposed P2P disallowance should be rejected (8T 2465-66, 2489).³⁹

2. Success Factors

Mr. Coppola proposed a \$9.1 million disallowance for the SuccessFactors project, claiming that the project seemed expensive, and that "[a]lligning compensation programs with business

³⁹ Mr. Coppola's proposed \$5.1 million disallowance for the bridge period and projected test year period is also greater than the Company's \$4.9 million request for this period (8T 2466; Exhibit A-12, Schedule B5.7.1).

objectives is usually a process of compensation plan design at a high level, and not an execution function requiring complex computerized systems” (9T 3000-3001).

Mr. Griffin responded by explaining that SuccessFactors is the Company’s Human Resources management system. The vendor that supplies the software that the Company uses is retiring that software and therefore the Company must replace it. Company witness Griffin explained that “The Company requires time and attendance software, training management software, payroll software, and other human resources software to effectively manage a workforce commensurate to its size.” (8T 2467.) Allowing the software to lapse into unsupported obsolescence is not a viable option (8T 2467, 2538).

The Commission approved \$1.6 million for the program in the rate base for 2018 in Case No. U-20162, demonstrating an interest in its continuation. The Company is continuing with this multi-year program and continues to seek \$8.8 million for four program modules as Mr. Griffin explained in his direct testimony (8T 2370). After that direct-testimony filing, the Company decided to expand the investment to include an additional (fifth) module. The Company understands that the resulting increase in the capital investment will need to be presented in a future rate case (8T 2467-68). Mr. Griffin further explained the business benefits for each module (Time and Attendance, Employee Learning Management, Workforce Planning Metrics Pack, Payroll, and Compensation Management), which were previously provided in the business case for this program in Exhibit A-24, Schedule N1 – IT Business Cases – Executive summaries (8T 2468-69).

Mr. Coppola expressed concerns only about the Compensation Management module, yet he proposed a complete disallowance of the entire investment in the program. Therefore, Mr. Coppola’s proposed disallowance is largely unexplained. The proposal is also unfounded and inappropriate, as outlined above. Mr. Coppola’s suggestion that there may be some additional

uncertainty and/or lack of support also neglects Mr. Griffin’s direct testimony and the Business Case Documents (8T 2370, 2469-70; Exhibit A-43, Schedules HH3, HH4, HH5, HH6, HH7 and HH8). Therefore, Mr. Coppola’s proposed SuccessFactors disallowance should be rejected.⁴⁰

3. Bill Redesign

Staff recommended a complete \$5.524 million disallowance (\$1.252 million for the bridge period, and \$4.272 for the test year) for the Bill Redesign project, reasoning that “to further reduce customer complaints regarding bill design is not reasonable or prudent when over 99.99% of all DTE Electric customers have not filed MPSC complaints regarding the current bill design in the last two years and when further reduction of MPSC complaints is the key metric for program success” (9T 3369).⁴¹ Mr. Coppola took a similar position, reasoning that the project’s value was questionable without “specific evidence...to show that there is broad-based dissatisfaction or confusion with the format of the bill” (9T 3003-3004).⁴²

Mr. Griffin disagreed, explaining that while one of the metrics for the program would be MPSC complaints, that is not the sole indicator of success, nor is it the driving consideration behind the investment. Instead, the project is justified because the Company presently generates approximately 36,000,000 bill statements annually (paper and electronic). The current bill format is not flexible enough to display all transactions as new rates and products are added. This can result

⁴⁰ Mr. Coppola’s proposed \$9.1 million SuccessFactors disallowance for the bridge period and projected test year is also greater than the Company’s \$8.8 million request for this period (8T 2470; Exhibit A-12, Schedule B5.7.1).

⁴¹ Staff further recommended an O&M reduction for IT capital projects that were disallowed of \$576,252 for the Bill Redesign project and \$600,000 for the Network-AMI Enhanced Support project (9T 3369-70; Exhibit S-3, Schedule C5, line 7). These adjustments are improper because the Company’s projected O&M was based on 2018 historical expense, adjusted for inflation and other specific adjustments (Exhibit A-13, Schedule C5). The amounts were not included in the Company’s projection adjustments, so there is no basis for Staff’s proposed disallowances (6T 1559, 1561-62).

⁴² Mr. Coppola’s proposed \$5.7 million disallowance for the bridge period and test year is greater than the Company’s \$5.5 million request for this period (8T 2472; Exhibit A-12, Schedule B5.7.1).

in items missing from the bill. The Company must use IT and Customer Service resources to manually add an “Adjustment” line on approximately 2,000 bills per week or approximately 104,000 bills per year to resolve the missing items and ensure that accurate billing statements are delivered. This persistent and systemic subset of bills are known as Out of Balance (OOB) bills. They confuse and frustrate employees and customers because the transactions and associated “Adjustment” lines are not easy to explain. This often results in calls to the Company’s contact center. Once the bill has been redesigned, the Company projects a 5% decrease in billing-related calls, a 3% increase in Billing First Call Resolution (FCR) for calls related to this line-item adjustment current billing software, and an estimated 95% reduction in OOB bills by the end of 2020. Moreover, these improvements are anticipated to produce \$1.8 million of cost savings annually, consisting of: (1) \$1.2 million in material savings through the ability to use standard bill stock and standard envelop size; (2) \$166,000 for eliminating the full cost of a full-time equivalent employee having to do manual bill adjustments; and (3) \$500,000 due to the elimination of 5% of billing-related calls (8T 2497-98, 2534-35). These improvements are expected to increase customer satisfaction, with an ancillary benefit of a corresponding 8% reduction in customer complaints (8T 2472). Therefore, the Company’s requested cost recovery should be approved (8T 2471-72, 2534-35).

4. Digital Engagement Group Establishment

Staff recommended a complete \$9.2 million disallowance (\$2.303 million for the bridge period; \$6.897 million for the test year) for the Digital Engagement Group Establishment project, indicating that there is uncertainty with its objectives, benefits, and costs (9T 3370-71). Mr. Coppola took a similar position (9T 2999-3000).

Mr. Griffin disagreed, explaining that approximately 73% of customer interactions with DTE occur through the Company's digital channels (such as Mobile Application, Website & Interactive Voice Response (IVR) system). The Digital Experience Group (DEG) will be a new group that will focus on its mission to serve customers by delivering a unified and seamless digital experience. The Company proposes that the DEG will do this by aligning the Company web channel's performance and capability with other interactions that customers experience elsewhere and adopt the best practices that drive performance. This is important because while most customer transactions occur on-line, a lack of a common approach between systems and limited functionality means fewer customer transactions are occurring without also resulting in an accompanying call to the customer call center. The DEG will focus on closing those gaps and utilizing new technology that will greatly reduce the number of self-service transactions that require the customer to place a call to the customer call center. Customers expect to be able to complete their online transactions without having to call the company for assistance. Establishing a new group within Customer Service to focus on this problem will be far more efficient because at present, complaints and other issues regarding web functionality are not all fielded by the same group within customer service or IT. Mr. Griffin further detailed the underlying reasons and expected results for transaction-optimization efforts in the categories of: Move In Move Out (MIMO) (eliminating approximately 1 million calls to the customer call center annually, or 1/5 reduction in calls); Outage (also reducing customer calls to call center); Payments, Billing, Collections (reducing live calls); and Service Capabilities (reducing live calls). Therefore, the Company's requested recovery should be approved (8T 2473-74).

5. Web Portal Rebuild

Mr. Coppola proposed a \$17.8 million disallowance for the Web Portal Rebuild and Transformation project (9T 3002-3003). Mr. Griffin first explained that Mr. Coppola's criticisms were based in part on an incorrect narrative that was provided to the parties in the Top 25 highest cost IT/OT project list. The correct description and supporting data were included in the Executive Summary for the business case (Exhibit A-24, Schedule N1.29).⁴³ It appears Mr. Coppola relied upon the Top 25 narrative rather than the Executive Summary for the business case, therefore, some of Mr. Coppola's criticisms lack relevance to the actual project (8T 2475).

Mr. Griffin further disagreed with Mr. Coppola's proposed disallowance, explaining that the Company's current website implementation is no longer robust enough to support the variety of features expected in a modern digital experience. This results in the website having the lowest customer satisfaction rate among the Company's digital channels at 72% and contributes to the nearly 5 million calls to the contact center each year. The dedicated Web Transformation project will improve the website's performance by moving to a more robust cloud architecture that will improve the current load times and customer experience, which will also reduce costs because customer service representatives will need to handle fewer calls. Therefore, the Company's requested recovery should be approved (8T 2476, 2536, 2510-11).⁴⁴

⁴³ The business case describes the project as follows: "The Company will invest \$17 million in the Web-Portal Rebuild and Transformation project to bring the standard DTE Electric web application architecture to current industry standard, as the cumulative technologies supporting the presentation of the Company's web-presence have aged and are increasingly limited in functionality. Not investing in this area would represent a serious risk to customer interaction with the Company on the web, which continues to be a preferred avenue of communication and service." (8T 2475).

⁴⁴ Mr. Coppola's proposed \$17.8 million disallowance for the bridge period and projected test year is also greater than the Company's \$17.2 million request for this period (8T 2476; Exhibit A-12, Schedule B5.7.2).

6. 2019 Emergent project and the Applied Innovation project

The 2019 Emergent project and the Applied Innovation project are the same project, which was renamed for 2020 and beyond (8T 2477). Staff recommended a partial disallowance for the 2019 Emergent project, reasoning that “There is great uncertainty in these projects, not only in scope, benefits, and usefulness, but also project costs” (9T 3367). Staff recommended a full disallowance (\$482,000 for the bridge period; \$4 million for the test year) for the Applied Innovation project, reasoning that the costs are speculative (9T 3368).

Mr. Griffin acknowledged that the Commission previously agreed with Staff that the 2018 Emergent project was speculative, resulting in a disallowance (May 2, 2019 Order in Case No. U-20162, pp 41-43). He explained that 2018 was the first time the project was included in a rate case, so there was a lack of historical data to demonstrate that the investment would be carried out as described. Staff indicated that the Company should include the investment in a future case once the investment had been concluded. The Company did so, demonstrating that the method used to project spending is sound, and in line with UNITE Best Practices for Energy and IT organizations (8T 2408-2409, 2478-79; Exhibit A-12, Schedule B5.7.5).

The forecasted investment for 2019 Emergent did not prove to be speculative as Staff suggested. As of November 2019, enough data is available to demonstrate prudent and planned expenditures in alignment with Mr. Griffin’s testimony in Case No. U-20162 and his direct testimony here (Exhibit A-12, Schedule B5.7.5). Mr. Griffin provided additional quantified detail demonstrating that the Applied Innovation project is similarly non-speculative (8T 2479-80; Exhibit A-24, Schedule N1.69).

Mr. Coppola proposed a \$5.3 million disallowance for Applied Innovation,⁴⁵ asserting that “it is not clear why the Company would need to spend \$8 million to develop a system to keep track of innovation items” (9T 2999). Mr. Coppola’s criticism appears to be based on a misunderstanding of the program. In addition to the discussion above, Mr. Griffin explained that DTE Electric does not intend to spend \$8 million to develop or otherwise acquire a tracking tool. The Company is instead broadening its focus on electric reliability through emergent and active initiatives in the innovation pipeline. For example, the use of drones is expected to yield operational productivity, specifically with considerable improvements in pole top inspection and storm response (8T 2480).

7. Network Advanced Metering Infrastructure (AMI) Enhanced Support

Staff recommended a complete disallowance (\$2.465 million for the bridge period; \$2.2 million for the test year) for the Network Advanced Metering Infrastructure (AMI) Enhanced Support project, reasoning that it is unnecessary to improve the AMI mesh read rate because it is well above the Commission’s Service Quality and Reliability Standard of 85%, and that the Commission agreed with the Staff to disallow costs for a similar reason in Case No. U-20162 (9T 3371-72).

The Company disagrees. As discussed above in section VI.F. (regarding AMI), the 85% performance level was set before the deployment of AMI infrastructure. Company witness Ms. Robinson explained that the 85% performance level is clearly untenable and would drastically undermine core benefits of an AMI system. Staff’s position on the 4G optimization phase also appears to be based on a fundamental misunderstanding. The main purpose of strengthening the communications network is to *sustain* read rates, not *improve* them (9T 2631-32).

⁴⁵ Mr. Coppola’s proposed \$5.3 million disallowance for the bridge period and projected test year is greater than the Company’s \$4.8 million request for this period (8T 2480-81; Exhibit A-12, Schedule B5.7.5).

Mr. Griffin further explained that there are multiple reasons why the Network AMI Enhanced support expense is both prudent and timely. Maintaining or improving the read rate is just one of those reasons. The Company operates its AMI system using a private mesh network (6518 devices that interconnect to form a communications grid that allows the Company to currently average a 99.2% connection rate with its meter devices). The mesh network must be highly reliable and resilient to ensure that the Company can effectively control and reliably operate meter devices. The communication rate must be as high as possible because gaps or holes in the mesh network can result in groups of meters losing connection to the system. If this happens, then the Company cannot operate or read the meters, requiring physical site visits by field service personnel (8T 2418, 2482-83).

Moreover, the fact that the spending would affect the meter read rate should not shift the focus from Asset Health to improved read rates. The investment is first and foremost for the systematic identification and replacement of deployed network assets on a planned cadence. This ongoing scheduled replacement ensures that the system is refreshed and up to date at all times. Improvement of the read rate is an ancillary benefit, without which DTE Electric would still need the program. Therefore, the Company's requested recovery should be approved (9T 2483-84).

J. Corporate Staff Group

Corporate Staff Group (CSG) capital spending for physical infrastructure, fleet and other projects was \$114.1 million in 2018, and is projected to be \$208.7 million for 16 months ending April 30, 2020, and \$131.0 million for 12 months ending April 30, 2021 (Exhibit A-12, Schedule B5.8, page 1, line 8). Ms. Uzenski explained and supported the larger projects included in the categories on Exhibit A-12, Schedule B5.8, line 1 (Electric Vehicle Fleet), line 2 (Facilities Construction & Upgrade), line 3 (Facilities Renovation), line 4 (Service Center Optimization), line

5 (Headquarters (HQ) Energy Center), line 6 (Security Measures), line 7 (NERC-Critical Infrastructure Program), line 8 (Robotics Process Automation), line 9 (Customer Service Print Room Upgrade),⁴⁶ and line 10 (Other Miscellaneous). (6T 1523-32).

The Commission previously approved capital expenditures for the HQ Energy Center (May 2, 2019 Order in Case No. U-20162, pp 46-47). Ms. Uzenski recounted the project's necessity and benefits, and explained that the plan design was only about 30% complete when Case No. U-20162 was filed. It is now about 90% complete. The expected costs have increased by about \$10 million, but the NPV analysis still demonstrates that building a new facility is better than maintaining the old systems (6T 1526-29). Therefore, the additional capital expenditures should be approved.

More specifically, the HQ Energy Center is a new facility that will include a steam plant fueled by natural gas, and a chilled water plant for the downtown campus. The Company needs a steam production facility because it currently depends on purchasing steam from Detroit Thermal, which has increased prices by approximately 5% annually since 2013, and the Company has experienced negative impacts from Detroit Thermal's planned and unplanned outages. The Company also needs a new chilled water system because the current chilled water system is at the end of its useful life (6T 1526-27).

The Energy Center will provide benefits by reducing the number of chillers from the existing seven to four high-efficiency units, which will provide energy savings estimated at 2.5 million Kwh/year. The Energy Center will also be easily accessible, with reduced maintenance costs and labor needs. Regarding natural gas fired steam boilers, the Company believes that it can better control steam costs and improve operational effectiveness by using a system that it owns and

⁴⁶ Mr. Campbell further supported this \$2.5 million capital expenditure for two bill printers and three bill inserters to replace existing equipment that has been experiencing repeated down time, resulting in increased overtime as employees make up the lost productivity. Machine errors also cause the need to replace bills (8T 2564).

operates. The forecasted capital investment for the Energy Center is \$39.4 million, resulting in a net present value (NPV) of the revenue requirement of approximately \$62.0 million. This compares favorably to an NPV revenue requirement of up to \$65 million under the status quo (6T 1527-28).

As discussed in Section I above, the Company has accepted Staff's adjustment (at 9T 3202) to remove \$3.2 million of contingency related to the Energy Center (Rate base impact of \$2.3 million and depreciation impact of \$158,000).

K. 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. [May 2, 2019 Order in Case No. U-20162, p 115.]

Accordingly, Mr. Clinton provided an update on the cost projections for Charging Forward's primary components, including (1) Direct Current Fast Charging (DCFC) pilots, (2) Customer Education & Outreach, (3) Residential Smart Charger Support, (4) Charging Infrastructure Enablement, (5) Additional Elements, and (6) Program Management (6T 1001, 1003-1008). A complete status update and strategy overview of Charging Forward and all of its components is set forth in Exhibit A-29, Schedule T1, which is the Charging Forward Pre-Implementation Status Report that the Company filed on May 28, 2019 in Case No. U-20162.

Estimated program costs are \$2.9 million in 2019, \$4.6 million for the 16 months ending April 20, 2020, and \$5.4 million for the projected test year ending April 30, 2021 (6T 1004-1005;

Exhibit A-12, Schedule B5.9, page 1, line 20).⁴⁷ Three of the Company's planned DCFC pilots (Beacon Park, Capitol Park, and Meijer in Auburn Hills) will require additional funding (6T 1005; Exhibit A-12, Schedule B5.9, columns (e) and (f), lines 2 and 9). With regard to Additional Elements, the Company is expanding the program's scope to include an updated EV-Grid Impact Study and EV-Ready Builder Rebate Pilot (6T 1007; Exhibit A-12, Schedule B5.9, columns (e) and (f), line 16)). DTE Electric presently intends to include multifamily dwellings in the EV-Ready Building Program (6T 1065).

Exhibit A-13, Schedule C5.9.1 calculates the amortization expense. The projected test period amortization amount of \$628,000 is carried to O&M Exhibit A-13, Schedule C5.9, line 12, column (1). (6T 1513).

Staff proposed a total disallowance of \$1,280,000 for the Plug-in Electric Vehicle and Charging Forward programs (9T 3338-41; Exhibit S-3, Schedule C5.3). For the U-17767 Plug-in Electric Vehicle amortization, the Company agrees that four months of amortization should be excluded, but the amount should be \$415,000 (based on an end date of 1/1/2021) rather than Staff's recommended \$347,000 (which assumed an end date of 1/20/2021). (6T 1574).

For the Charging Forward program, Staff proposed disallowing return of and on Charging Forward expenditures, except for amounts that had undergone a prudency review as of September 19, 2019. DTE Electric understands that amortization of the regulatory asset for ratemaking purposes can only include amounts audited by Staff (May 2, 2019 Order in Case No. U-20162, p 115). Depending on the timing of future rate cases and Staff's reviews, however, some costs will not be recovered at all because the Company is required to start amortization expense for accounting purposes the year after the costs are incurred (*Id.*). Therefore, the amortization balance should be included in rates to slightly mitigate the loss from amortization expense that is above the amount in

⁴⁷ Total estimated Charging Forward expenditures are \$14 million through the end of 2021 (6T 1004).

rates. This would not provide full recovery *of* the deferred costs, but it would at least provide a return *on* the unamortized balance. Otherwise, Staff's approach would not simply delay recovery – it would result in a permanent loss of a return on the unaudited amounts. Accordingly, the Commission should reject Staff's proposed reduction of the regulatory asset balance and accept the Company's projected average balance of \$4.3 million (shown on Exhibit A-12, Schedule B4, line 31). This approach is reasonable because it allows a return on some of the deferred costs, while including only the audited costs to be recovered through amortization expense (6T 1560, 1575). As discussed in Section I, DTE Electric has reduced O&M to reflect only amortization of the audited costs. (see Attachment A, page 3).

In response to Staff and Mr. Jester's proposed changes in the Charging Forward program (9T 3373-78, 3851-52), Mr. Clinton explained that stakeholder meetings are the appropriate venue for discussing program modifications, as well as program reporting requirement changes or additions. To the extent that any program modifications are appropriate and agreed upon, they will be included in the Company's annual status report (6T 1046).

VII. RATE OF RETURN

DTE Electric requests a weighted, after-tax 5.73% overall rate of return (6T 1461; Exhibit A-14, Schedule D1, line 10, column (g)), which the Commission should adopt for all the detailed reasons set forth below.

A. Capital Structure

1. Debt and Equity Balances

DTE Electric seeks to maintain its permanent capital structure of 50% debt and 50% equity, (6T 1452, 1463; Exhibit A-14, Schedule D1. See also April 18, 2018 Order in Case No. U-

18255, p 25; May 2, 2019 Order in Case No. U-20162, pp 54-55). Staff agreed (9T 3318). So did the AG (9T 3009).

Mr. Solomon explained 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 (the *availability* of capital), and ability to raise capital at reasonable terms and rates (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 (6T 1452-55).

Mr. Solomon further explained that 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 51%, as the Company explained in Case No. U-20162. The Commission previously maintained DTE Electric's 50/50 capital structure, reasoning that "conditions have not changed to such a degree as to warrant a departure from a balanced equity ratio at this time" (May 2, 2019 Order in Case No. U-20162, p 55). Mr. Solomon testified that waiting for a negative event to occur could be detrimental to DTE Electric's financial health. A 50% equity ratio gives the Company little protection in the event of an unforeseen market event, and might impact DTE Electric's ability to access capital during the projected test period (6T 1456).

DTE Electric will be financing and funding over \$4.0 billion of electric capital expenditures for the period of January 2019 through April 2021 (Exhibit A-12, Schedule B5).⁴⁸ A capital structure with at least 50% equity is essential to DTE Electric's credit quality and financial soundness, which will in turn ensure the reasonableness and competitiveness of the Company's capital costs during this period of significant system investment (6T 1457-58).

Despite DTE Electric's higher expected capital expenditure relative to assets as compared to the electric peers (6T 1334), DTE Electric's 50% equity ratio is lower than the 52.4% average for the Company's peer group (Exhibit A-14, Schedule D1.1). In other recent peer utility rate cases, the MPSC has authorized a 52% or higher equity ratio for all utilities except DTE Electric. Therefore, DTE Electric's 50% equity ratio is reasonable and well below the equity ratios of its peers across the country and within Michigan (6T 1456-57).

DTE Electric also had a 51% equity ratio on December 31, 2018, and is committed to maintaining a 50% equity ratio. DTE Energy has made \$1.2 billion of equity infusions since 2014, plans equity infusions of about \$300 million in 2019, and will infuse the amounts necessary in future years to maintain a 50% equity ratio (6T 1458).

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 in section VII. C. 3 (regarding ROE). Accordingly, the Commission should maintain DTE Electric's 50% equity ratio.

⁴⁸ Moreover, as discussed above, particularly in sections VI. A. and C (regarding capital expenditures for Fossil Generation and Distribution Operations), DTE Electric has capital needs to address its aging infrastructure to ensure reliability and safety.

2. Accumulated Deferred Income Tax (ADIT)

In Case No. U-20162, ABATE proposed a “regulatory plan” involving the faster amortization of unprotected excess ADIT balances. The Commission declined to adopt ABATE’s proposed regulatory plan, but found that “in DTE Electric’s next general rate case, the parties should evaluate the benefits and costs of an accelerated amortization of the excess unprotected ADIT” (May 2, 2019 Order in Case No. U-20162, p 60). In this case, ABATE witness Mr. Walters again presented a “regulatory plan” to accelerate the amortization periods for DTE Electric’s unprotected excess ADIT balances (7T 1891-98).

Mr. Walters specifically recommended “the 23 year amortization period for plant-related unprotected excess ADIT be reduced to 13 years, and the 14 year amortization period for non-plant unprotected ADIT be reduced to 9 years” (7T 1893). He further asserted that: “As shown on page 3 of my Exhibit AB-28, I have calculated the net present value (‘NPV’) of the reduction in revenue requirement based on the current amortization schedules and my proposed amortization schedules through 2030, when Belle River is scheduled to be retired . . . under my proposal, customers are better off by approximately \$129.8 million through 2030” (7T 1897).

Ms. Suchta explained that Mr. Walters’ NPV analysis is incorrect. The primary mistake is that he did not carry his analysis out far enough, so he did not capture all of the impacts of the two scenarios being compared. By ending his analysis in 2030, Mr. Walters ignored the amortization of excess ADIT after that date. He should have extended the NPV analysis to 2042 in order to correctly include the full amortization of the excess ADIT under both scenarios (9T 3423).

Exhibit A-42, Schedule GG1 takes Mr. Walters’ Exhibit AB-28 and carries the revenue requirement out through 2042, in order to properly analyze the impact of the two scenarios. Ms. Suchta also made two other necessary corrections, but the remaining inputs and calculations were left unchanged. The corrected NPV analysis shows that customers would be better off by

approximately \$41 million under the Company's proposed excess ADIT amortization schedule rather than under ABATE's proposed regulatory plan (9T 3423-24).

Mr. Solomon further explained how ABATE's proposed accelerated ADIT amortization would negatively impact the Company's cash flows and financial integrity. There would be a \$34 million incremental yearly cash flow loss to the Company, which would be directly reflected in the numerator of the Company's Funds from Operations (FFO)/debt calculation, which is a key financial metric used by credit agencies. Long-term debt would also increase because the Company would have to fund the cash loss with a mixture of debt and equity. The incremental pro forma impact would be a reduction to the FFO/debt ratio of approximately 0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the Company's financial integrity. There would also be a negative long-term impact to customers because accelerating the ADIT would effectively replace deferred taxes (which have zero funding cost) with debt and equity in the Company's capital structure. Plus, the impact would grow each year as debt balances grow, with only a partial offset for earnings on equity. The lower rates that customers would experience in the early years would be offset by higher capital costs after ten years. This impact could be exacerbated if the Company experiences higher interest costs due to lower credit ratings (6T 1467-68).

Ms. Crozier further explained that the higher interest rates (which could arise due to the negative impact on cash flows lowering the company's credit rating) would result in higher financing costs. This would negatively impact the Company's ability to serve its customers and maintain its distribution and generation assets, because the more dollars that are required to pay for financing costs, the fewer dollars that would be available for customer service and system maintenance (4T 506).

Therefore, the Commission should again decline to adopt ABATE's proposed regulatory plan

B. Debt Cost Rates

1. Long-Term Debt

DTE Electric recommends a 4.31% 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 (6T 1453, 1460-61, 1463; Exhibit A-14, Schedule D2). Staff recommended 4.22% (9T 3319; Exhibit S-4, Schedule D1, line 1, column (e)). The difference in recommendations is due to Staff's projected interest rates of 3.54% for bonds issued in 2020, and 4.13% for bonds issued in 2021. The Company used 4.21% for 2020, and 4.25% for 2021. Staff suggested that its projected rates were more appropriate because they utilized more recent projections based on 30-year Treasury yield projections as of September 2019 (9T 3320).

Mr. Solomon explained that interest rates and interest rate forecasts are changing constantly. The Company's forecasted long-term debt interest rates were based on data from May of 2019. Staff's interest rates were based on data from September of 2019. The 30-year Treasury rate as of May 1, 2019 was 2.94%. By September 2, 2019, it declined about 1.0% to 1.95%. By November 15, 2019, it was up 0.36% to 2.31%. This increase in the interest rate is further significant because it was after the Federal Open Market Committee (FOMC) cut rates by 25 basis points in September and October of 2019; *i.e.*, the recent interest rate increase after the FOMC rate cut was the opposite of Staff's prediction that a FOMC rate cut might drive interest rates lower than projections. Therefore, the Company maintains that the rates provided in its initial filing were, and remain, a reasonable and prudent projection of long-term debt interest rates. Assumptions underlying

forecasts can change from time to time, but it would be unreasonable to adjust forecasts based on every market fluctuation (6T 1465-66).

2. Short-Term Debt

DTE Electric recommends a 3.25% 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 (6T 1453, 1461-63; Exhibit A-14, Schedule D3). Staff recommended 2.73% (9T 3319; Exhibit S-4, Schedule D1, line 5, column (e)). The difference in recommendations is due to Staff's use of LIBOR projections of 1.94% for 2020, and 2.26% for 2021 (9T 3320). The Company used 2.55% for 2020, and 2.60% for 2021. As discussed above regarding long-term debt rates, the Company maintains that the rates provided in its initial filing were, and remain, a reasonable and prudent projection of short-term debt rates. It would be unreasonable to update forecasts based on every fluctuation in underlying assumptions (6T 1466).

AG witness Mr. Coppola proposed to increase the amount of short-term debt used in this case from the Company's forecast of \$219.9 million, to \$337.2 million, reasoning that it "seems reasonable to expect some greater utilization of short-term debt going forward" because the Company increased the size of its short-term debt credit facilities with financial institutions (9T 3009-11).

Mr. Solomon disagreed, explaining that the Company's \$219.9 million balance of short-term debt is a reasonable average amount of outstanding short-term debt for the Company. Short-term debt is an important tool that the Company uses to maintain liquidity. The Company increased its credit facilities from \$400 million to \$500 million in order to maintain ample liquidity in a time of increased capital expenditures. The Company needs to be in a position to fund any large expenditures or cash draws that might occur, and have ample unused liquidity for any unforeseen

or unexpected cash needs. The Company's projected level of short-term debt provides that ample liquidity, so it should be adopted (6T 1467).

C. Return of Common Equity

Dr. Villadsen explained and recommended that a just and reasonable Return on Equity (ROE) for DTE Electric's common equity capital is 10.5%.⁴⁹ This is at the upper end of Dr. Villadsen's range of 9.75% to 10.75% because DTE Electric has greater-than-average risk. Staff witness Mr. Megginson recommended 9.80% (9T 3291, 3293, 3313-3313A). AG witness Mr. Coppola recommended 9.25% (9T 2963, 3012, 3014). ABATE witness Mr. Walters recommended 9.2% (7T 1826, 1873). The Staff, AG, and ABATE recommendations are downward biased because they fail to take into account the interaction of capital structure (financial risk) and ROE. They also failed to adequately capture the risk in the electric utility industry, and failed to consider relevant information from other highly regulated companies. It is difficult to imagine, for example, that DTE Electric's investors require a return that is substantially lower than the return in highly-regulated natural gas and water utilities. The recommendations are also understated due to analytical errors and the misperception that DTE Electric has average risk relative to sample companies. Instead, the changes in the capital markets (rising interest rates, increasing bond yields, and increased market volatility), the challenging Michigan economic environment, the differences in financial risk for DTE Electric as compared to sample companies, and the large-scale disruptive changes in the electric utility industry justifies an increase in the recommended ROE for DTE Electric relative to the sample companies (6T 1207-1209, 1269-70, 1310-18, 1344, 1347-48).

Dr. Villadsen selected a sample of 26 regulated electric utility companies as well as a sample of 11 water and natural gas utilities that are similar to DTE Electric because they are rate regulated

⁴⁹ DTE Electric has no preferred stock (Exhibit A-14, Schedule D4).

by state utility commissions, serve customers through a network of assets, and are capital intensive. She further explained that using both a sample of electric utilities and a sample of highly-regulated utilities in other industries (water and gas) is advantageous in the current environment, where the electric utility industry is undergoing a transition to cleaner fuels, more self-generation, technological changes, and the resulting consequences for the grid. Such industries provide a clearer picture of the regulated industry without being in the middle of a transition (6T 1208, 1212, 1216, 1238-44, 1270, 1332-35).

Dr. Villadsen estimated the ROE for each company in his sample using two versions of both the Capital Asset Pricing Model (CAPM),⁵⁰ and Discounted Cash Flow (DCF) approaches, as well as a risk premium model. She then combined the ROE estimates from the CAPM and DCF models with capital structure information. By determining the after-tax weighted-average cost of capital, she avoided inconsistencies that could arise from estimating the cost of equity for companies without considering 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). She also considered Hamada adjustment procedures to provide further insight into the range of ROE estimates after adjusting for financial leverage (6T 1212-16, 1300-1306). 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 (6T 1318-30). By failing to account for fundamental financial principles, the Staff, AG and ABATE ROE estimates are downward biased by 60 to over 100 basis points (6T 1329).

⁵⁰ The CAPM is a risk positioning risk positioning approach. She also used the Empirical CAPM (ECAPM) (6T 1247).

1. CAPM and ECAPM Estimates

Dr. Villadsen developed ROE estimates based on the CAPM and on 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,⁵¹ and (c) a market risk premium (6T 1246-47).

As a proxy for the CAPM's risk-free interest rate, Dr. Villadsen used the 3.0% yield on the 10-year U.S. Treasury bond forecasted by *Blue Chip Economic Indicators* to be in effect in 2020, 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 basic risk-free rate of 3.5%. This rate is downward biased, however, as reflected for example by the spread between A-rated utility bonds and the 20-year government bond being elevated by 48 bps relative to its historical average. Therefore, her Scenario 1 adds about half of the increase (25 basis points) in the yield spread to obtain a risk-free rate of 3.75% (6T 1248).

Dr. Villadsen explained that the market risk premium (MRP) is forward looking. She used 6.91% (the historical average from 1926 to 2016) with her risk-free rate of 3.75% in her Scenario 1. She further explained that the 48 bps increase in yield spread could be viewed as an increase to the MRP, so for her Scenario 2, she calculated a 7.91% MRP (based on the forecasted yield from Bloomberg and FERC's recently-suggested methodology) that she used along with the lower risk-free rate of 3.5%. Importantly, she did not allocate the increase in yield spread to both the risk-free

⁵¹Beta 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 (6T 1247).

rate and the MRP in the same scenario. She opined that the 6.91% long-term historical MRP is a low-end estimate of what the MRP will be during the period at issue in this case, and that the 7.91% MRP is a good approximation for a forward-looking MRP. She used betas reported by Value Line, which she adjusted using the Hamada technique to account for DTE Electric's capital structure having a higher proportion of debt financing (and thus financial risk) than the sample companies (6T 1247-52).

Mr. Megginson suggested that the Company "used an inflated market risk premium of 7.91%" (9T 3305). But Dr. Villadsen pointed out that the cost of capital is forward looking, so estimation models require forward-looking estimates (6T 1327). Mr. Megginson's projected CAPM is consistent with this fundamental principle, and his testimony confirms that it "produced a total market risk premium of 11.82%," and a "Projected CAPM ROE estimate of 10.40%" (9T 3305). Mr. Coppola's criticisms of Dr. Villadsen's use of a 7.91% MRP is similarly unfounded and contrary to recent events (6T 1225-26, 1339).

Dr. Villadsen's main disagreement with Mr. Walters concerned his beta analysis. He noted "the sudden drop in beta estimates over the last year or so" (7T 1866), so instead of using current betas, he also used an average of beta estimates recorded by Value Line since 2014. He did not offer any explanation for why the beta drop may be significant, nor any reason why his solution may be appropriate to address the unexplained phenomena. In contrast, Dr. Villadsen's use of an expanded proxy group with regulated water and natural gas utilities provides appropriate insight into recent changes in the electric industry (6T 1332-35, 1338-39).

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, and high-beta stocks tend to have lower risk premiums

than predicted. Dr. Villadsen adjusted by using the ECAPM, which uses these empirical findings to produce results that more closely match the results of empirical tests, and that are more appropriate to use (6T 1252-54).

Staff (9T 3308-9) and ABATE (7T 1884-85) suggested that it is inappropriate to both use adjusted beta estimates and apply the ECAPM. Dr. Villadsen explained that they are two fundamentally different and complementary adjustments, with no redundancy. The adjustment to beta corrects the estimate of the relative risk of the company. The ECAPM adjusts the risk-return tradeoff. Both adjustments are necessary to produce the most accurate possible forward-looking estimate of the required return on equity. Failure to consider the ECAPM's results downwardly biases the results by approximately half a percent (6T 1245-47).

Dr. Villadsen's CAPM and ECAPM analyses produced ROE estimates of 8.3% to 11.1, with a majority of results in the 9.0% to 10.5% range. She explained, however, that the ECAPM numbers deserve more weight than the CAPM numbers because the ECAPM adjusts for empirical findings. Therefore, she gave somewhat greater weight to the ECAPM results and considered the lowest estimate from the CAPM to be too low (6T 1254-56). With regard to the alternative estimates, Mr. Megginson's Projected CAPM is appropriately forward looking, and its 10.40% results merits the most weight (6T 1311, 1344).

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. In order to apply the growth rates used in the DCF model, two components are required: (1) the forecasted earnings growth rates; and (2) the long-term growth rate. For the single-stage DCF and the first stage of the multi-stage DCF, Dr. Villadsen used earnings growth rates from *Value Line* and Thompson Reuters

IBES. For the long-term growth rate for the final, constant-growth stage of the DCF, she used the long-run GDP growth forecast of 4.0% from *Blue Chip Economic Indicators*. The corresponding ROE estimates are 9.9% for the Electric Utility Sample and 11.7% for the Water and Gas Sample using the single-stage model, and 8.4% for the Electric Utility Sample and 8.0% for the Water and Gas Sample using the multi-stage model. The multi-stage model is downward biased, however, due to the dividend yield likely being under-estimated and forecasted GDP growth being well below recently-experienced GDP growth. A reasonable low-end estimate of the cost of equity falls somewhere between the estimates from the two versions of the model, and the upper-end estimate is better approximated by the single-stage model. Thus, the DCF model at 50% equity supports a ROE range of 9.5% to 10.75% (6T 1217-18, 1256-60).

Staff, the AG, and ABATE used the single-stage (constant growth) DCF model, but they also used annualized dividend yields rather than quarterly dividend yields and growth rates. This artificially lowered their resulting ROE estimates. Staff also relied on overlapping growth rate estimates from reporting services, which risks overweighting the opinions of certain analysts (which are counted more than once) and biasing the results (6T 1340-41). ABATE's sustainable growth method is not properly implemented. Exhibit AB-15 indicates that the average expected return on book equity for Mr. Walters' electric sample is 10.7%. But he calculated a ROE of 8.41% for the electric sample and recommended a DCF based ROE of 7.5% to 8.4% (7T 1859). ABATE's numbers simply do not add up (6T 1311, 1341-42).

AG witness Mr. Coppola further acknowledged that "a potential 10% correction in utility stock prices due to higher interest rates would produce a 0.30% to 0.40% increase in the cost of capital under the DCF approach" (9T 3033-34). This acknowledgement is particularly significant due to current events, as further discussed below.

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. Dr. Villadsen found that current market conditions are consistent with an ROE of 10.2% to 10.3% for vertically-integrated utilities, which overlaps with the upper half of the estimates from the reasonable range from the DCF and CAPM models at 50% equity. Although the risk premium model based on historical allowed returns is not supported by fundamental financial principles like the CAPM or DCF models, it is a valid approach that provides a useful benchmark and direct comparison to the return available elsewhere for the cost of equity in any interest environment (6T 1260-63).

Mr. Megginson's projected Risk Premium analysis resulted in ROE estimates of 10.97% to 11.32% (9T 3311). These estimates are appropriately forward-looking, and deserve the most weight. The other parties' risk premium results otherwise suffer from analytical flaws that downwardly bias their results (6T 1311, 1343-44).

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

The Commission set DTE Electric's currently-authorized ROE at 10.0%, stating that it "agrees with DTE Electric that factors such as volatility and uncertainty are currently particularly significant, and movements are more extreme in comparison to more stable historical periods" (April 18, 2018 Order in Case No. U-18255, p 32). The Commission maintained that ROE in DTE Electric's last general rate case, stating that it "was not persuaded that economic conditions have changed sufficiently, if at all, to warrant an increase in DTE Electric's ROE . . . [but it] will continue to monitor a variety of market factors in future applications to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE" (May 2, 2019 Order in Case No. U-20162, pp 67-68).

In Case No. U-18999 (DTE Gas’s most recent general rate case), the Commission set the ROE at 10.0%, despite the ALJ’s recommended lowering of DTE Gas’s ROE from 10.1% to 9.6%. The Commission noted some improved conditions in the approximately two years since DTE Gas’s prior rate case, but stated that it “agree[d] with DTE Gas that there [was] increased volatility in the capital markets that may affect the cost of capital” (September 13, 2018 Order in Case No. U-18999, p 54). The Commission also emphasized that in the present regulatory environment where rate cases are more common (this is DTE Electric’s fifth rate case in six years), proposals to radically reduce a utility’s ROE (as ABATE and the AG have made) are neither realistic nor helpful to the Commission (September 13, 2018 Order in Case No. U-18999, p 52). 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 March 29, 2018 Order in Case No. U-18322, p 44.

Dr. Villadsen explained that interest rates are expected to increase going forward and utility bond spreads indicate an increase in the cost of equity (6T 1219-24). The elevation in the spread between utility bond yields and government yields indicates that monetary policy has put downward pressure on risk-free rates or that the MRP has increased, resulting in a need to “normalize” for modeling purposes, as she did with her Scenarios 1 and 2, discussed above with regard to the CAPM (6T 1220, 1224-30). Stock market volatility has increased, which is significant because investors expect higher risk premiums during more volatile periods, indicating that the MRP might increase when market volatility is high (65T 1230-33).

The Tax Cuts and Jobs Act of 2017 (TCJA) also results in reduced cash flows and increased volatility of cash flows, putting utilities such as DTE Electric at risk for a credit downgrade. The

lower tax rate and the loss of bonus depreciation causes utilities to lose some of their cash flow contribution from deferred taxes. This decreases the Funds From Operations (FFO) to debt ratio, which is a key metric that credit rating agencies use to measure credit quality. Credit rating agencies have expressed concern about the financial health of regulated utilities due to the negative impact of tax reform on the companies' cash flow and credit metrics (6T 1233-37). Moody's has evaluated all components of the TCJA as a drag on credit quality across the regulated utility industry, estimating that the average reduction in the ratio of cash flow to debt for utilities due to implementing the new tax law is 150-250 bps (6T 1236-37, quoting Moody's Investors Service, including "2019 outlook negative amid growing debt and stagnant cash flows," November 8, 2018).

This is also a particularly inopportune time to weaken the Company's credit metrics due to the TCJA and 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-17999 (DTE Gas's general rate case prior to U-18999, which is discussed above), the ALJ recommended an ROE of 10.0%, in accordance with Staff's recommendation. The Commission instead set the ROE at 10.1%, explaining in part: "Nationally, and in Michigan, ROEs are trending downward, and Michigan's economy has improved considerably since DTE Gas's last contested rate case. However, the Commission agrees with the company that economic conditions in parts of its service territory remain challenging and present a degree of risk perhaps greater than the risk associated with the proxy companies" (December 9, 2016 Order in Case No. U-17999, p 25).

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" (January 31, 2017 Order in Case No. U-18014, pp 65-66).

In Case No. U-17767 (DTE Electric's general rate case prior to U-18014), the Commission set DTE Electric's ROE at 10.3%, despite the ALJ recommending an ROE of 10.0%, in accordance with Staff's recommendation, explaining in part that "the Commission finds that an ROE of 10.3% will best achieve the goals of providing appropriate compensation for risk, ensuring the financial soundness of the business, and maintaining a strong ability to attract capital . . . DTE Electric has an ambitious capital investment program, much of which is related to environmental and generation expenditures that are unavoidable and are saddled with time requirements" (December 11, 2015 Order in Case No. U-17767, pp 54-55).

At about the same time, the Commission approved a 10.3% ROE for Consumers Energy (November 19, 2015 Order in Case No. U-17735, p 47). ABATE, which had recommended an ROE of 9.6%, appealed to the Court of Appeals. The Court of Appeals rejected ABATE's arguments and affirmed the 10.3% ROE. *In re Application of Consumers Energy Company to Increase Rates*, 322 Mich App 480; 913 NW2d 406 (2017).

In the current environment of low electric demand growth, DTE Electric's lack of a revenue decoupling mechanism or a fixed variable pricing policy 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 due to Michigan's economy, which is heavily dependent on the auto industry. DTE Electric's service territory is primarily in Southeastern Michigan including Detroit, which continues to experience a high unemployment rate and approximately 34% of its population lives under the federal poverty threshold. DTE Electric also requires significant capital expenditures to improve reliability and comply with environmental requirements, and 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 (6T 1263-69, 1347-48).

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 (6T 1213-16, 1245).

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

Business risks have increased since DTE Electric's last rate case and key macro-economic indicators such as interest rates are expected to increase going forward. Therefore, DTE Electric's ROE should be increased from the current 10%. A range of approximately 9.75% to 10.75% is reasonable for DTE Electric based on the DCF, CAPM and Risk Premium models, but DTE Electric has higher-than-average risk compared to the sample companies, so DTE Electric should be placed towards the upper end of that range. Thus, DTE Electric's ROE should be increased to 10.5% (6T 1207-1208, 1269-70).

It is also important to maintain DTE Electric's access to capital. Maintaining a solid credit rating and outlook is one important aspect to maintaining access to capital. A supportive allowed return on equity is important to ensure the utility's favorable access to credit markets. Maintaining a strong credit rating is particularly critical during a period forecast to have substantial capital investment for infrastructure. Therefore, estimates at the upper end of the ROE range are more representative of the cost of capital expected going forward.

D. Other Cost Rates

Tax law requires, and prior Commission orders have allowed, a return on Job Development Investment Tax Credits (JDITC) at the rate of return for permanent capital, so the associated returns for JDITC-Debt and JDITC-Equity reflect the corresponding permanent capital rates of 4.31% and 10.50%, respectively. Deferred income taxes are at zero cost (9T 3418; Exhibit A-14, Schedule D1, lines 6, 7 and 9, column (e)).

E. Overall Rate of Return

The sum of the weighted cost of the above-described capital components results in a weighted, after-tax 5.73% overall rate of return (9T 3414; Exhibit A-14, Schedule D1, line 10,

column (g)). A 1.3496 revenue conversion factor is appropriate for the projected period (9T 3415; Exhibit A-13, Schedule C2, line 9). The corresponding weighted pre-tax overall rate of return is 7.15% (Exhibit A-14, Schedule D1, line 10, column (i)). DTE Electric supports the use of the 5.73% overall rate of return in the derivation of its revenue requirements and the use of the 7.15% pre-tax overall rate for the return on rate base.

VIII. ADJUSTED NET OPERATING INCOME AND REVENUE DEFICIENCY

DTE Electric's Total Electric Adjusted Net Operating Income (NOI) was \$798,929,000 in the 2018 historical test year and was projected be \$788,214,000 in the projected test period (6T 1503, 1517; Exhibit A-13, Schedule C1, line 19). DTE Electric's operating income is projected to decrease due to increased depreciation and property taxes related to capital additions, higher depreciation rates, O&M inflationary increases, higher distribution and nuclear operating costs, and lower sales. The decrease in operating income is partially offset by higher revenues from new base rates in Case No. U-20162, effective May 2019 (6T 1516). Based upon the NOI related adjustments discussed in Section I above, the Company agrees to adopt those adjustments and update its projected test year NOI to approximately \$789.1 million (Attachment A, page 3).⁵²

A. Sales Forecast

DTE Electric employs a rigorous forecasting methodology to determine future sales (4T 404-21). This methodology is continuously reviewed, and has been highly accurate (4T 404, 421). The methodology utilized by the Company's forecasting expert Mr. Leuker included: (1) end-use analyses of the Residential Class with the consideration of 39 appliances or appliance groups (4T

⁵² RCG witness Mr. Crandall asserted that the Commission should order "an explicit downward adjustment to any rate determination" for the costs to comply with the U-20084 settlement (9T 2824-25). Ms. Uzenski responded that, as she indicated her direct testimony, the costs have already been removed or were excluded from the historical test period. Therefore, Mr. Crandall's proposal should be rejected (6T 1553-54, 1560, 1576).

405, 407-408); (2) regression analyses for the Commercial and Industrial (C&I) class customers by markets (4T 405, 409-10); (3) an EPRI-developed model called Hourly Electric Load Model (HELM) that aggregates hourly demand profiles from various sales categories or end-uses into a system annual load shape (4T 412); and (4) an autoregressive integrated moving average (ARIMA) based model to determine confidence bands around the forecasted bundled peak load (4T 413).

For the projected test period, service area sales are projected to be 46,007 GWh, and bundled sales are projected to be 41,307 GWh (4T 415; Exhibit A-15, Schedule E1, pages 1 through 3). Service area system output and annual peak demand are projected to be 49,309 GWh and 11,046 MW, respectively. Bundled system output and annual peak demand are projected to be 44,343 GWh and 10,232 MW, respectively (4T 415; Exhibit A-15, Schedule E2, pages 1 and 2).

Mr. Leuker further explained that service area sales are expected to be 46,450 GWh in 2019 and decrease to 44,911 GWh in 2029. This represents a 0.3% average annual decrease. Bundled sales are expected to be 41,668 GWh in 2019 and decline to 40,211 GWh in 2029. This represents a 0.4% average annual decrease (4T 416).⁵³

Mr. Coppola proposed using an historical 4-year average usage-per-customer (UPC) rate of change to forecast projected test year sales (9T 3037-40). Mr. Leuker explained that Mr. Coppola's

⁵³ DTE Electric's service area Residential Class sales are projected to decline 0.4% annually, on average, between 2018 and the projected period in this case, as well as during the forecast period from 2019 through 2029. DTE Electric's service area Commercial Class sales are projected to decrease 0.3% annually, on average, between 2018 and the projected period, as well as during the forecast period from 2019 through 2029 (4T 417). DTE Electric's service area Industrial Class sales are projected to decrease 0.7% annually on average, from 2018 to the projected period, and to decrease 0.4% annually, on average, from 2019 through 2029 (4T 418). DTE Electric's service area Other Class (which consists of street lighting and traffic signals) sales are projected to decline by 0.7% annually, on average, from 2019 through 2029 (4T 419). Choice sales are projected to increase from a temperature-normalized 4,674 GWh in 2018 to 4,700 GWh in the projected test period (4T 416).

DTE Electric's service area system peak demand in 2019 is expected to be 11,109 MW. Based on this peak and a forecast service area peak demand of 10,597 MW in 2028, an average compound growth rate of -0.5% is expected. DTE Electric's bundled peak demand was similarly forecast at an average compound annual growth rate of -0.6% from an expected bundled peak demand of 10,346 MW in 2019 to a forecast bundled peak demand of 9,783 MW in 2029 (4T 419-20; Exhibit A-15, Schedule E2, page 2).

methodology is flawed and his resulting proposal to raise residential and C&I sales should be rejected. Mr. Coppola's methodology is an oversimplification that does not take into account factors that need to be considered when determining a forecast. The Company's forecast properly considers these factors, specifically: the growth of the EWR program, the adoption of customer-owned generation, customer-specific actions such as planned plant openings or closings, and the current and future state of the economy. Moreover, Mr. Coppola has repeatedly submitted different, apparently outcome-based methodologies in different cases with no supporting documentation or reasoned analysis for changing his approach from case to case (4T 426-34).

Assuming for argument's sake that Mr. Coppola's currently-proposed methodology is valid (which it is not as indicated above), the Company re-created it using actual sales from 2019 (ten months of weather-normalized actuals and two months of forecast). The results support the Company's original forecast by indicating that the Company slightly under-forecasted residential sales by 1 GWh (14,725 GWh compared to original 14,724 GWh) and slightly over-forecasted C&I sales by 249 GWh (30,824 GWh compared to original 31,073 GWh). Breaking out D3 customers again supports the Company (7,028 GWh compared to the original 7,052 GWh forecast) and not Mr. Coppola (7,165 GWh forecast). (4T 427-29; Exhibit A-38, Schedule CC1).

Thus, there is no reasoned basis to adopt Mr. Coppola's sales forecast methodology, and Mr. Leuker's sales projections should be adopted.

B. Power Supply Costs

DTE Electric proposes to maintain the current Power Supply Cost Recovery (PSCR) base of 31.26 mills per kilowatt-hour at the generation level, which the Commission established in its December 23, 2008 Opinion and Order in Case No. U-15244, and maintained in subsequent cases. The Company proposes to update the loss factor, however, which will result in a PSCR base of

33.54 mills per kilowatt-hour at the sales level as reflected on Exhibit A-13, Schedule C-4. Ms. Holmes explained that the 7.3% loss factor is based on the current relationship of net system output to system sales in the Company's sales forecast. It is essentially the amount by which sales would need to be grossed up to reach the required system output. The Company does not project any PSCR over or under-recovery in this case. The Company's proposed rates reflect the 33.54 base, and the Company used a zero PSCR factor to calculate revenues for the projected period (8T 2250, 2252-54).

Mr. Jester suggested that the Company's proposal to update the loss factor from 6.8% to 7.3% should be rejected, reasoning that the evidence supporting the change cannot be relied upon since it is based on an outdated study (9T 3806). Ms. Holmes responded by explaining that Mr. Jester's reasoning is inaccurate, so his recommendation should be given no weight. The proposed 7.3% factor is based on Mr. Leuker's sales forecast. Mr. Leuker did not use a loss factor to develop the sales forecast; instead, he developed the sales forecast independently (as discussed above) and then applied a loss factor to the forecasted sales to calculate the total system area output. The loss factor used by Witness Leuker was not based on an outdated study, but instead was derived by dividing the most recent 48 rolling months service area net system output by the most recent 48 rolling months service area sales (8T 2262-63; Exhibit A-35, Schedule Z1).

Staff witness Ms. Shi recommended using a 7.23% loss factor, which resulted in a power supply expense \$789,774 lower than the amount Ms. Holmes projected using the Company's proposed 7.3% loss factor. To offset Ms. Shi's adjustment to PSCR base expense, Staff witness Mr. Isakson made an adjustment to present revenue by applying a PSCR factor of negative \$0.0002 per kilowatt-hour for full service customers (9T 3120).

Ms. Holmes explained that the negative PSCR adjustment to present revenue is unnecessary and should be eliminated. Ms. Shi's projected power supply expense is a projected cost that is an input in Staff's calculated revenue deficiency. There should be no adjustment to present revenue, which is calculated using current rates (including the PSCR base and existing 6.8% loss factor). Staff's adjustment to present revenues artificially (and perhaps unintentionally) increased the Company's revenue deficiency (8T 2264). 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 \$1,269.2 million of adjusted O&M in 2018, which was projected to increase to \$1,353.4 million in the projected test period (Exhibit A-13, Schedule C5, line 12, columns (f) and (l)). As discussed in Section I, the Company's projected O&M has been adjusted by a \$1 million reduction related to Electric Vehicle amortization (9T 3302) and a \$0.3 million elimination of membership fees included in error, resulting in \$1,352.1 million (See Attachment A, page 3).

1. Inflation on O&M expense

Ms. Uzenski calculated inflation rates of 2.8% for 2019, 2.9% for 2020, and 1.0% for January 1 through April 30, 2021, as shown on Exhibit A-13, Schedule C5.15, line 15. These are composite rates using a 3.0% inflation rate for labor, and the consumer price index (CPI)-Urban for non-labor costs (6T 1507). Mr. Cooper further explained that he conservatively estimated annual wage increases of 3.0% for 2019, 2020, and 2021, 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 910-12).

The Commission previously declined to adopt a proposed composite inflation rate, observing that it “has never found sufficient justification or support to approve a composite labor/non-labor inflation rate” (January 31, 2017 Order in Case No. U-18014, p 72), and that “DTE Electric has not presented sufficient evidence in this case to induce the Commission to depart from its decisions” (April 18, 2018 Order in Case No. U-18255, p 38, and May 2, 2019 Order in Case No. U-20162, p 74). DTE Electric submits that the record 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 approximately 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 911.]

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 2019 that resulted in an overall pay increase of about 3.0%, just as it was in 2018 and every year since 2010. Employees also receive pay increases based on promotions (5T 911).

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 anyway would seek an illegal result that merits no serious consideration. DTE Electric cannot violate its Collective Bargaining Agreements, and the Commission has no authority to become involved in or dictate results of collective bargaining. Additionally, Ms. Crozier explained that although the Company’s ability to manage O&M in the past has been exceptional, the Company cannot continually reduce non-labor O&M to offset wage growth (4T 464). Therefore, the Commission should approve DTE Electric’s proposed composite inflation rate.

Kroger witness Mr. Bieber opined that inflation should not be included for non-labor costs and outside services and proposed a \$7.4 million O&M reduction to remove non-labor inflation,

and a \$25.5 million O&M reduction to remove outside services inflation (8T 2163-66). Ms. Uzenski disagreed because it is unreasonable to assume zero inflation when published inflation rates (including Mr. Bieber's own cited authorities) support expected inflation. Therefore, Kroger's proposal should be rejected as unfounded (6T 1560, 1566).⁵⁴ The Commission also previously rejected essentially the same argument by Kroger (May 2, 2019 Order in Case No. U-20162, pp 72-74). Therefore, the Company's proposed composite inflation rates are fully justified and should be adopted.

2. Fossil Generation O&M Expense

DTE Electric's actual and forecast Fossil Generation O&M expenses consist of three major categories: (1) Steam Power Generation, (2) Hydraulic Power, and (3) Other Power Generation, as shown on Exhibit A-13, Schedules C5.1, C5.4, and C5.5 (5T 627). Mr. Morren explained the major line items and adjustments (5T 628-34). Steam Power Generation adjusted O&M was \$281.0 million in 2018, and is projected to be \$286.6 million in the 12-month projected test period ending April 30, 2021 (Exhibit A-13, Schedule C5.1, page 1, line 19, columns (g) and (m)). Hydraulic Power adjusted O&M was \$10.6 million in 2018, and is projected to be \$11.3 million in the 12-month projected test period ending April 30, 2021 (Exhibit A-13, Schedule C5.4, line 17, columns (e) and (k)). Other Power Generation adjusted O&M was \$15.8 million in 2018, and is projected to be \$16.8 million in the 12-month projected test period ending April 30, 2021 (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 Fossil Generation historical and projected O&M expenses are reasonable and prudent, and therefore should be recovered (5T 634).

⁵⁴ Mr. Bieber's proposed \$32.9 O&M million adjustment is also mathematically incorrect. The correct amount for non-labor and outside services revenue is \$31.2 million, as shown on Exhibit KRO-1 (6T 1566).

As discussed above in section VI. A, because of extensive repairs identified during a February 2019 outage at St. Clair Unit 1, the Company requested approval from MISO to retire the unit. MISO approved with an effective date of March 27, 2019.⁵⁵ The Company removed \$1.4 million of expense from its rate request to reflect the lower future O&M expenses after the retirement (5T 632, 638; Exhibit A-13, Schedule C5.1, page 1, note 6). AG witness Mr. Coppola asserted that “[a]ccording to my calculations, the adjustment to future O&M should be \$4.5 million (9T 3055).

Mr. Morren responded by explaining that Mr. Coppola used three different calculation methods to arrive at three different values, none of which are supported by St. Clair Unit 1’s specific design, maintenance, or staffing requirements. Mr. Coppola’s first method relied on a discovery request showing that the St. Clair Power Plant O&M differed by \$4.3 million between 2017 and 2018, which he suggested “can be mostly attributed” to the retirement of St. Clair Unit 4 (9T 3056). Mr. Morren explained that Mr. Coppola’s unsupported supposition was inaccurate because the O&M change was influenced by multiple additional factors, including the plant’s receipt of \$8.0 million of fire recovery O&M insurance proceeds in 2018 based on insurance claims that it had filed previously for the 2016 plant fire. This materially altered the 2018 booked total plant O&M expenses and demonstrates that Mr. Coppola’s first method is invalid (5T 639-40).

Mr. Coppola next opined that the Company’s \$1.4 million adjustment was “not accurate” simply because “if we divide the \$36,425,389 of O&M expense incurred in 2018 by the five power

⁵⁵ The Commission previously approved St. Clair Unit 1 capital expenses for the May 2018 through April 2019 test year, but noted the then-recent shutdown and stated that “the Commission expects the utility to repurpose the capital expense associated with St. Clair Unit 1 on this record after the date of the shutdown of that unit for use on other units in need, and to present that expense information in its next rate case” (May 2, 2019 Order in Case No. U-20162, p 13). Mr. Morren testified that approximately \$0.2 million associated with St. Clair Unit 1 was redirected to support the remaining operating units at the St. Clair power plant (5T 620).

generating units operating that year, including Unit #1, the average expense per unit was approximately \$7.3 million” (9T 3056).

For his third methodology, Mr. Coppola observed that the nameplate capacity of the St. Clair plant decreased 12.4% after the retirement of Unit 1. Mr. Coppola then multiplied this 12.4% by \$36,425,389 to arrive at \$4.5 million (9T 3056-57). Mr. Morren explained that these methodologies are invalid because a retirement impact analysis requires a thorough understanding of plant-specific design, maintenance, and staffing requirements before a meaningful analysis can be made. Mr. Coppola’s simple observations about total O&M expense and mathematical calculations are not reasonable proxies for such an understanding. For example, some equipment and operating personnel support more than one unit, so retiring one unit does not eliminate certain control room functions and workforce requirements (5T 640-41).

In contrast to Mr. Coppola’s simplistic and faulty analysis, the Company supported its O&M expense reduction as indicated above, and provided a discovery request (Exhibit A-39, Schedule DD1) that further breaks down the retirement O&M reduction analysis into categories of labor, materials, outside services, forced outage, and furnace cleanings (5T 638). Therefore, the Company’s \$1.4 million O&M reduction estimate associated with the St. Clair Unit 1 retirement should be adopted (5T 641).

3. Fuel Supply and Midwest Energy Resources Company O&M Expenses

Mr. Milo supported DTE Electric’s Fuel Supply and Midwest Energy Resources Company (MERC) O&M expense of \$9.3 million in 2018, and projected to be \$10.0 million in the 12-month projected test period ending April 30, 2021 (9T 3923, 3927-28; Exhibit A-13, Schedule C5.2, page 1, 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 2018 expense adjusted for

inflation and those expenses should be determined to be reasonable and prudent (\$5.9 million for Fuel Supply and \$4.1 million for MERC, as shown on Exhibit A-13, Schedule C5.2, column (1), lines 7 and 15) (9T 3227-28). There is no disagreement and the Company's Fuel Supply and MERC O&M expense recommendations should be adopted.

4. Fermi 2 O&M Expenses

Mr. Davis supported Fermi 2's 2018 actual, as well as projected, nuclear O&M expenses through April 30, 2021 (9T 3430-31). Actual O&M expenses for 2018 were \$187.7 million (9T 3447; Exhibit A-13, Schedule C5.3, page 1, line 24, column (c)). Two adjustments are necessary. First, column (d) reflects a \$28.0 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 \$4.9 million PERC base level and the \$4.4 million PERC Regulatory Asset amortization are not inflated in the projected adjustments (9T 3447-49). See also January 31, 2017 Order in Case No. U-18014, p 74.

PERC expenses over or under \$4.9 million are deferred. The Company spent \$30.7 million on PERC projects in 2018 (largely driven by the 24-Month Operating Cycle project, as the Commission recognized in the May 2, 2019 Order in Case No. U-20162, p 122), and expects to spend \$19.9 million in 2019, \$17.6 million in 2020, and \$16.0 in 2021 (Exhibit A-13, Schedule C5.16). Exhibit A-13, Schedule C5.17 shows the derivation of the PERC amortization. The Company proposes to increase the \$4.9 million annual PERC Base Expense by \$10.1 million to \$15.0 million (\$1 million less than the lowest annual PERC forecast) to reasonably reflect Nuclear Generation operations. As the 24-Month Operating Cycle project completes, annual PERC O&M expenditures are projected to levelize at approximately \$16.0 million in 2021. If the Company does

not spend at least \$15 million per year, then in accordance with the Order in Case No. U-18014, the underspent amount would be used to reduce the regulatory asset balance, which had grown to \$43.4 million as of December 31, 2018 (6T 15611-12; 9T 3456-58).

Adjusted O&M expenses for 2018 were \$159.7 million (Exhibit A-13, Schedule C5.3, page 1, column (f), line 24), and were used to forecast projected O&M expenses through April 30, 2021 (22). Mr. Davis explained various O&M expenses and adjustments, and testified that \$186.5 million of O&M will be required to support the safe and reliable operation of Fermi 2 in the projected period ending April 30, 2021, which is prudent and reasonable (9T 3448-60; Exhibit A-13, Schedule C5.3, page 1, line 24, column (m)).

The Commission previously adopted the ALJ's recommendation to require DTE Electric to submit an updated decommissioning study (May 2, 2019 Order in Case No. U-20162, p 121). The Company initiated the project to update the Fermi 2 decommissioning study soon after the Commission's Order; however, nuclear decommissioning studies are complex, require allocation of Company resources, and take many months to complete. The PERC O&M Nuclear Decommissioning Study is the mechanism for DTE Electric to provide a comprehensive and fully-transparent update to the existing Fermi 2 decommissioning study, depicting the most reasonable and accurate view of Fermi 2's future decommissioning, which is not expected to occur until at least 2045. The study is forecasted to be completed in May 2020. Mr. Davis supported the reasonableness of approximately \$1.6 million of forecasted expenditures for Calendar Years 2019 and 2020 (\$0.9 million for 2019, and \$0.7 million for 2020). (9T 3459-60, 3465; Exhibit A-13, Schedule C5.16, page 1, line 23).

ABATE witness Ms. Alderson did not dispute the decommissioning study's overall scope, schedule, supplier strategy or total projected expenditures. She proposed a reduction in DTE

Electric's recovery of expenditures, however, reasoning that it lacked support and DTE Electric is unlikely to make expenditures beyond the contract commitments that the Company had awarded as of September 2019 (7T 1813-14; Confidential Exhibit AB-5).

Mr. Davis responded by explaining that Ms. Alderson's proposal should be rejected as unfounded and unreasonable, emphasizing that he previously explained to ABATE that the Company was performing the overall decommissioning study, instead of delegating that responsibility to a single third-party supplier as part of a turnkey project. He also clarified for ABATE that this nuclear decommissioning study is different from, and broader in scope than, only a decommissioning cost estimate (9T 3465-68; Exhibit AB-3, pages 1 and 8).

Mr. Davis also disagreed with Ms. Alderson's assertion that DTE Electric did not provide workpapers supporting its requested recovery, explaining in part that Ms. Alderson's own Exhibit AB-3 (page 8) shows that DTE Electric responded to ABATE's request for workpapers stating that the Company provided the detailed forecast (or workpaper) in Attachment 9 of the Part III submission (9T 3467-68). This detailed forecast is reframed as Exhibit A-34, Schedule Y1 CONFIDENTIAL. Mr. Davis explained and supported the activities, dollar amounts, and appropriateness of the activities reflected by the various line items (9T 3469-71).

Moreover, Ms. Alderson's proposal is particularly unreasonable because it would cause DTE Electric to under-recover for a nuclear decommissioning study that ABATE advocated and the Commission ordered, even though the scope, schedule, supplier sourcing strategy and total forecasted expenditures of the PERC O&M Nuclear Decommissioning Study are reasonable and prudent. Therefore, ABATE's proposal should be rejected, and the Company's full requested recovery should be approved (9T 3471).

5. Distribution Operations O&M Expenses

Distribution Operations' O&M expenses are driven primarily by day-to-day trouble and storm restoration, tree-trim work, and system maintenance requirements (4T 230). The Company projects \$336.5 million of O&M expenses for the projected test period ending April 30, 2021 (Exhibit A-13, Schedule C5.6, p 1, line 26, column (1)). The forecast is based on actual 2018 O&M expenses, normalized and adjusted. Mr. Bruzzano explained and justified significant components and adjustments underlying the projected O&M costs, as reflected on Exhibit A-13, Schedule C5.6, and supported the actual and projected O&M costs as reasonable and prudent (4T 230-34).

Mr. Coppola agreed with the Company's five-year normalization approach to forecast storm and non-storm restoration expense for future years, but asserted that "it should be done using actual incurred expenses from prior years, as opposed to recast numbers with additional assumed costs for prior year inflation" (9T 3050). Mr. Bruzzano explained that the AG's position is incorrect. Instead (as discussed above in section VI. C regarding DO capital expenditures), prior years' expenditures must be expressed in a constant-dollar denomination because the value of a dollar changes over time due to inflation (for example, the purchasing power of a dollar in 2014 is not the same as the purchasing power of a dollar in 2018). Therefore, the Company properly brought the expenditures to a common 2018-dollar denomination (using the CPI for 2014, 2015, 2016 and 2017 expenditures, as shown on Exhibit A-31, Schedule V-2, page 31) and then averaged them to calculate the starting point for projections (4T 262-65). The Company's methodology is also consistent with the methodology that the Commission approved in past cases (4T 211, 228, 247-48, 265). Therefore, the AG's proposed methodology should be rejected.

There is similarly no merit in Mr. Coppola's further proposal to disallow inflation in projected periods (9T 3046). The AG's proposal is unfounded and unreasonable because the Company has presented evidence that it experiences inflationary pressures (4T 267-68). Mr.

Coppola alternatively recognized that the Commission has granted inflationary cost increases in past cases, but asserted that the “CPI-Urban index inflation rates proposed by the Company are now stale,” and proposed that the Commission use more recent information on Exhibit AG-1.30 (9T 3047). The Company disagrees because its projected expenditures were developed at a point in time. It would be inappropriate to selectively choose cost elements that have declined without acknowledging other elements that may have increased over the same period (4T 268). See also sections VIII. C. 1 (regarding Inflation on O&M Expense) and VI. C. (Distribution Operations capital expenditures) for further discussions regarding inflation.

Michigan’s 2013 ice storm left tens of thousands of customers without power and demonstrated that historic tree trimming practices were insufficient. The Commission recognized that trees are the primary cause of power outages, and that DTE Electric was fully spending its allocated funding for vegetation management to prevent such outages (May 2, 2014 Order in Case No. U-17542, p 16; December 4, 2014 Order in Case No. U-17542, pp 4-5). Therefore, DTE Electric began investing in a new Enhanced Vegetation Management Program (EVMP, now re-named the Enhanced Tree Trimming Program or ETTP), which essentially removes vegetation in a clearance corridor rather than the historic clearance circle around DTE Electric’s lines and equipment. The Commission approved the ETTP in Case No. U-17767, and increased funding to clear more miles of lines in Case No. U-18014. In Case No. U-18255, the Commission again approved increased ETTP funding, emphasizing the importance of expenditures to improve the distribution system’s safety and reliability (April 18, 2018 Order in Case No. U-18255, pp 43-44). Most recently, the Commission again recognized the importance of tree trimming, and approved DTE Electric’s seven-year surge proposal, in part, stating:

The Commission reiterates its desire for a safe and reliable electric system as stated on pp. 43-44 of the April 2018 order regarding the ETTP program. The record shows

that DTE Electric has continued to bring tree trimming spending into line with the approved amounts, and the Commission agrees that falling behind in this area will cost more in the future and perpetuate reliability challenges. The record also shows direct, quantifiable benefits in terms of reliability improvements resulting from the ETTP program. . . The Commission finds it appropriate to move forward with the surge proposal as the best way to balance these considerations, but to only authorize the first three years. Thus, the Commission approves the originally-requested \$95.1 million of O&M for tree trimming in the projected test period, and the first three years of spending for the surge program, being \$43.3 million for 2019, \$74.1 million for 2020 and \$70.5 million for 2021, as a regulatory asset, with application of the short-term debt cost rate adopted in this order of 3.56% rather than the pretax permanent overall cost of capital proposed by DTE Electric [May 2, 2019 Order in Case No. U-20162, pp 79-80.]

Against this background, Ms. Rivard testified that in 2018, DTE Electric trimmed 3,668 line-miles (compared to a plan of 4,090 miles, but that was 105% of “comparable unit” work as discussed below) at a cost of \$89.2 million (\$5.4 million more than the \$83.7 million of funding approved in Case No. U-18255, which had a projected test year of November 1, 2017 through October 31, 2018). The actual volume of work completed exceeded the target, but the Company was below its miles target due to a shift to more dense and complex work in the City of Detroit. The Company is piloting the use of “comparable units” to more accurately measure tree-trim work performed. Work volume is defined by tree density. The Company’s circuits range from less than 10 trees per mile to more than 1,000 trees per mile. Work complexity measures many factors that influence the cost to perform work, including back lot work, security, off-cycle work and customer outreach. In 2018, after accounting for a small shift in miles due to capital work retiming, the Company exceeded its target by completing 105% of its comparable unit work (9T 3584-89).

Ms. Rivard further explained that the Company has begun executing the first year of its surge. The Company plans to trim 4,100 miles and 17,081 units in 2019 (432 more miles and 4,287 more units than in 2018). The estimate in Case No. U-20162 to trim 5,072 miles in 2019 with surge funding was based on an average mile (average density and average complexity). In 2018 and

2019, the Company prioritized circuits for trimming based on reliability impacts, wire down reductions, and the number of years that have passed since the last trim, with much of that effort focused on the City of Detroit. Frequent outage circuits generally have a high density compared to the Company's system average. Completing high density circuits at the start of the surge results in fewer miles trimmed, but the same amount of work completed. Trimming overgrown circuits with high trouble volumes first will also help the Company stay on target for completing the surge as planned, increase customer satisfaction, and reduce overall costs (9T 3590-92, 3605-3609). The Company has significantly ramped up tree-trim spending in 2019 and is projected to reach the authorized amount for the surge (9T 3617).

The ETTP is a well-designed program with proven success and continuing importance. Circuits trimmed as part of the ETTP since 2015 have a 64% reduction in tree-related interruptions in the year after trimming, which is dramatically better than the 13% reduction produced by the historical practice of just trimming a "clearance circle" around conductors. ETTP-trimmed circuits similarly showed an average annual reduction of approximately 61% in the number of customer minutes of interruption in the year following trimming, compared to non-ETTP circuits. Circuits trimmed as part of the ETTP also performed much better than the remainder of the system during the March 8, 2017 wind storm (9T 3584, 3592-99).

In compliance with the Commission's reporting requirements (May 2, 2019 Order in Case No. U-20162, p 81), the Company will provide annual reports starting March 1, 2020, and a Tree Trimming Effectiveness Report in 2022 (9T 3626-27). Staff recommended that in the annual report, "DTE Electric discuss progress the Company is making toward achieving an adequate level of qualified local workers in the tree trimming workforce" (9T 3231-32). The Company agrees to provide an update on the number of local journeymen and the number of local apprentices in its

annual reports for the duration of the surge program. The Company will also provide updates on any programs in which it is participating to increase the number of local tree trimmers (9T 3631).⁵⁶

The Company recently made several significant improvements to its tree-trimming program, including: (1) transitioning most of its work to fixed-bid contracts, (2) successfully implementing and expanding its mowing alleys pilot in the City of Detroit, and (3) implementing a herbicide program in 2018, and treating 1,448 miles (9T 2599-3600). The Company is also currently working on additional improvements, including: (1) partnering with its tree-trim contractors on new ways to improve production using innovative tree-trim equipment, (2) piloting the use of LiDAR information to provide accurate tree densities for all City of Detroit circuits, and (3) utilizing its arborist employees to set up a specialized estimating team to price out circuits before contractor bids are evaluated (9T 3600-3602).

The tree trimming surge program needs to continue because, as discussed in the Company's Five-Year 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. No other program in the Company's portfolio of distribution projects will have a greater impact on

⁵⁶ UWUA witnesses Harmon and Smith described the forecasted high volume of utility worker retirements in the near future, and recommended that the Commission direct the Company to provide money to the UWUA's training trust fund to facilitate the training of the next generation of utility workers (9T 2743-46, 2750-52). The Company shares the witnesses' concerns about the talent loss due to retirements, and the need to train new utility workers. The Company therefore continues to work with the UWUA to inform this and other labor-related challenges to DTE Electric; however, selecting solutions to these challenges is ultimately the responsibility of the Company's management (4T 506). In *Union Carbide v Public Service Comm*, 431 Mich 135; 428 NW2d 322 (1988) our Supreme Court explained:

“The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions. It must never be forgotten that while the State may regulate with a view to enforcing reasonable rates, it is not the owner of the property of public utility companies and is not clothed with the general power of management incident to ownership.” *Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm*, 262 US 276, 289; 43 S Ct 544, 547; 67 L Ed 981 (1923).” 431 Mich at 148-49. *See also Consumers Power Co v Public Service Comm*, 460 Mich 148, 157; 596 NW2d 126 (1999).”

mitigating risks, improving system and customer reliability, and managing the costs of operating the Company's distribution system (9T 3602-3603).

The tree trimming program should be funded to maintain a trimming cycle where circuits are re-trimmed before the trimmed trees grow 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 is based on the facts that (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 (9T 3603-3605, 3609).

Reducing the tree-trimming cycle to five years will provide multiple customer benefits and savings including: (1) lower customer complaints from tree-related events; (2) fewer wire down events, resulting in improved safety; (3) 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; (4) lower future tree-trimming costs; and (5) lower customer costs as tree-related outages are reduced (9T 3609-10). Ms. Rivard 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 downed wires), 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 (9T 3628).

Ms. Rivard 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 (9T 3628). A net present value (NPV) analysis further indicates that continued execution of the surge is \$92.6 million favorable to customers as compared to just the baseline O&M tree trimming amount of \$95.1 million per year (9T 3419, 3610; Exhibit A-22, Schedule L1). This \$92.6 million benefit is based just on the forecasted reduction in revenue requirement through 2040, without even considering the value of improved reliability to customers (9T 3610).

The Commission previously approved the first three years of the surge program (May 2, 2019 Order in Case No. U-20162, quoted above), so the program is adequately funded for the first three years (through 2021). An additional year of funding would allow the Company to continue planning work and secure tree-trimming contractors so that those contractors can, in turn, acquire or retain the necessary resources without interrupting the tree-trimming program.⁵⁷ Accordingly, the Company requests \$58.2 million of surge funding for 2022 (4T 470; 9T 3615-16).

Mr. Coppola proposed that the Commission deny the 2022 surge program extension, claiming that “there is not sufficient evidence to assess the merits of a program that was approved only a few months ago” (9T 3051-52). Ms. Rivard disagreed, referencing her direct testimony (outlined above), which provides sufficient evidence that the surge program is effective in reducing outage events, customer interruptions, customer outage minutes, and downed wires (9T 3594-98, 3633).

⁵⁷ Ms. Rivard further discussed the number of tree trimmers that are needed, the risks to maintaining a stable number of tree trimmers, and the Company’s efforts to grow the local work force (9T 3621-24).

Mr. Coppola further suggested that DTE Electric’s new three-year contracts that extend through 2023 “should remove any concerns about not having enough contractors for the year 2022” (9T 3652). The suggestion neglects that the contracts do not guarantee any volume of maintenance work. If the Company cannot provide work volume guarantees in 2021 for the full 2022 surge program work volume, then contractors will likely elect to move some of their trimmers and equipment to other areas of the country where they have guaranteed work volumes (9T 3633).

Mr. Coppola further suggested that “if the Company strongly believes that over the coming three years the surge program has achieved the benefits claimed in Case No. U-20162, it can proceed with the required amount of surge spending for 2022 [and] later request inclusion of those costs in the regulatory asset for future recovery in a subsequent rate case” (9T 3052). The Company is unwilling to proceed in that manner. Instead, the Company is committed to demonstrating the value of the ETTP to the Commission to ensure that the surge program remains a priority, and that the Commission authorizes funding before it is spent on the surge program (9T 3634).

Exhibit A-13, Schedule C5.6.1 shows tree trimming expenses for the projected test period. The annual amounts that the Commission approved in Case No. U-20162 are broken into Tree-Trim O&M – Base Level (line 2); and Tree Trim Regulatory Asset -Surge Funding (line 3). The \$97.9 million of base level O&M includes only inflationary increases for Reactive Maintenance and the Herbicide program,⁵⁸ which were authorized at \$12.2 million and \$2 million, respectively (4T 469; 9T 3616-17; Exhibit A-13, Schedule C5.6.1, line 9, column (b)).

⁵⁸ The herbicide program is based on industry best practices. In 2018, the Company expanded the use of 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, so the area will become a habitat for pollinators, birds and small animals. 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 (9T 3625-26).

Mr. Coppola also proposed to disallow \$2.8 million of inflation on the \$95.1 million base amount approved in Case No. U-20162, and recommended that no additional funding increase be authorized for the tree trimming program “until the Company provides additional evidence that more funding is needed above what was authorized in Case No. U-20162 for the base amount and the surge program” (9T 3050-51).

Ms. Rivard disagreed, explaining that the Company was transparent in Case No. U-20162 that inflation amounts would be needed. Failure to approve annual inflation increases would cost the Company approximately \$46.3 million in tree trimming funding over the course of the surge program. This is roughly equivalent to reclaiming 2,300 tree trim circuit miles. The entire base funding, including inflation, is needed to complete the surge program (9T 3631-33).

Total forecasted tree-trimming costs are expected to be \$1.12 billion from 2019 through 2025. Of this amount, \$707 million is proposed to be recovered through base rates (the \$97.9 million for the projected test year increased by inflation through 2025). The Company proposes to recover up to \$410 million through regulatory asset treatment. The Commission approved \$187.9 million through 2021 (May 2, 2019 Order in Case No. U-20162, p 80). In accordance with the U-20162 Order, the Company has treated the surge amounts for the bridge period and projected test year as a regulatory asset, and has accrued interest at the Commission-approved short-term debt rate of 3.5%. Exhibit A-11, Schedule A1.1 identifies the \$2.1 million return on Tree Trim Surge Regulatory Asset for the projected test period (9T 3418). Amortization of the surge amounts is not included in this rate case filing. As discussed in Case No. U-20162, DTE Electric still plans to seek

securitization⁵⁹ of the deferred asset once it reaches approximately \$100 million (4T 471; 9T 3619-20).

ELPC witness Villarreal proposed that the Commission withhold a portion of DTE Electric's requested tree-trimming cost recovery pending new performance-based requirements to ensure that tree-trimming funding is used only for tree-trimming (9T 2703). Ms. Rivard explained that this proposal should be rejected because:

1. The Company has already demonstrated that the tree-trimming program delivers superior performance results (9T 3594-98, 3633-34);
2. The Company has a consistent history of spending its authorized tree-trimming funding (9T 3634-35); and
3. The Commission's approved surge program funding mechanism already discourages financial transfers from the tree-trimming program to other programs in the Company (9T 3634-36).

Therefore, the Commission should adopt the Company's tree-trimming requests and the Company's agreement with Staff's additional reporting requirement, and reject all contrary and additional proposals.

6. Community Lighting O&M Expenses

Mr. Bellini supported DTE Electric's Community Lighting O&M expenses for 2018 through the projected period ending April 30, 2021 (9T 3478). O&M expenses for street lighting and signal systems (reflected on Exhibit A-13, Schedule B5.6, page 1, lines 8 and 22) are held

⁵⁹ 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. For example, Case No. U-12478 concerned DTE Electric's 2001 Fermi 2 securitization financing.

steady at the 2018 historical level of \$2.8 million, adjusted only for inflation and the 2018 implementation of an LED washing and group relamping preventative maintenance program, to \$3.8 million in the projected test period (9T 3485-87).⁶⁰ Mr. Bellini supported these expenses as reasonable, testifying: “I base this on my analysis of past expenses, projected requirements for labor and material for the safe and reliable distribution of electric power, and plans for maintaining and/or improving customer service” (9T 3488). There is no disagreement and the Company’s proposals should be adopted.

7. Customer Service O&M Expenses

Mr. Campbell supported the actual and projected O&M expenses for the Customer Service organizations as reasonable and necessary (8T 2547-64; Exhibit A-13, Schedule C5.7).⁶¹ These O&M expenses (including rate case adjustments) were \$93.9 million for the 2018 historical test period, and are expected to increase to \$108.8 million for the projected period ending April 30, 2021 (8T 2547, 2550-51, 2563; Exhibit A-13, Schedule C5.7). Mr. Campbell discussed the work activities performed in 2018 (8T 2551-60) and testified that the projected O&M increase is based on continuing those activities, with inflation of \$5.5 million for 2019 through April of 2021,⁶² Customer 360 regulatory asset amortization of \$0.7 million, and a known and measurable

⁶⁰ DTE Electric implemented its LED washing and group relamping preventative maintenance program in 2018 based on studies that identified a need to periodically wash LEDs to ensure that their lumen output provides acceptable lighting for customer safety and security design requirements (9T 3486).

⁶¹ The Customer Service organizations are Customer Care, Customer Billing, Revenue Management and Protection (RM&P), Customer Service Operations, Exceptions Management, and Customer Service Transformation. These organizations are responsible for billing, customer contact, and payment acceptance (8T 2548-50).

⁶² The rate of inflation is 2.8% for 2019, 2.9% for 2020, and 1.0% for the first 4 months of 2021 (6T 1507; Exhibit A-13, Schedule C5.15, line 15).

adjustment for fees paid to process credit card payments (merchant fees) of \$8.7 million (8T 2563-64).

Mr. Clinton further explained that based on a three-year compound average growth rate (CAGR), merchant fees related to residential customers have increased by 17.5%, and merchant fees related to non-residential customers have increased by 51.4%. Applying these growth rates to the \$10.5 million 2018 historical expense, the projected test year expense is \$19.1 million (6T 1008-1009; Exhibit A-13, Schedule C.5.7.1, page 1, column (g), line 5, and page 2, column (i), line 8).⁶³

It is important to smaller customers for the Company to continue to process bill payments using a debit or credit card, but it is also reasonable to expect larger, more sophisticated commercial and industrial customers to use more common business-to-business forms of payment, such as a check or electronic bank payment, with significantly lower costs to the Company. The Commission previously approved the Company's proposal to prohibit industrial customers in rate schedules D6.2, D8, D10, D11 and secondary choice customers from using debit or credit cards (May 2, 2019 Order in Case No. U-20162, p 85). The Company now proposes to further limit larger commercial and industrial (C&I) customers from paying electric bills by debit or credit cards if their preceding calendar year aggregate annual electric bill was more than \$75,000. If this change is adopted, then the test year merchant fee expense would be reduced by \$4.7 million, to \$14.5 million (6T 1009-10; Exhibit A-13, Schedule C5.7.1, page 2, column (i), line 10)).

Mr. Coppola apparently agreed with the Company's proposed \$75,000 C&I cap, but noted that the Company did not include the corresponding \$4.7 million reduction in its projected test year O&M expense, so he recommended the removal of \$4.7 million of merchant fees from the projected

⁶³ AG witness Mr. Coppola suggested that debit and credit card use grew in popularity because the Company "advertised" it as a "cost-free option" (Cop 104). Mr. Clinton explained that the Company does not publicly advertise that payments by debit or credit card are a cost-free option. The growth of debit and credit card payments follows national trends (6T 1047).

test year O&M expense (9T 3058). The Company agrees in part. If the Commission adopts the proposed \$75,000 C&I cap, then the Company requests \$17.1 million for recovery of merchant fees. This is a \$2.0 million reduction during the projected test year. Due to the timing of the Commission's Order in this case, the cap would not be implemented until January 1, 2021, since the Company would need time to implement the required technology changes and to effectively manage the customer experience through the transition (6T 1049).

Staff proposed that “the Company limit the customers utilizing the Merchant Fee service to only residential, and only the projected test year residential amount of \$8,399,000 be approved” (9T 3284). The Company disagrees. Instead, as indicated above, a reasonable and balanced approach to mitigate merchant fee costs and customer impacts is to also allow debit or credit card use by smaller C&I customers whose aggregate bill is less than \$75,000 per year. Not allowing debit and credit card use by these smaller C&I customers (numbering 34,000 in 2018) would negatively impact customer satisfaction by requiring them to change their payment methodology, and likely drive increased call center volume. Moreover, providing flexible payment methods such as debit and credit cards can assist customers in paying their bills to re-establish service or avoid service disconnection (6T 1048, 1148)

8. Uncollectible Accounts Expense

Uncollectible expense is recorded in the income statement to reflect the portion of accounts receivable (AR) that is considered uncollectible. DTE Electric included \$51.6 million of uncollectible expense based on a 2015-17 three-year average of actual uncollectible expense, reflecting planned efforts to sustain results despite continuing economic challenges for many customers (6T 1143-44; Exhibit A-13, Schedule C5.8, page 1, line 1, column (e)). DTE Electric has

worked proactively to reduce uncollectible expense, and is continuing its initiatives to prevent uncollectible expense (6T 1146-47).

Ms. Johnson explained that the Company used its three-year average of 2015-17 because uncollectible expense was abnormally high in 2018. The Company's methodology (three-year historical average of uncollectible expense as recorded in account 904) is also least prone to error because it is a straight forward and easily-verifiable calculation using figures from the Company's books. In contrast, Staff used a three-year average based on net write-offs, resulting in an uncollectible expense of \$46.8 million (9T 3276). The Company recognizes that the Commission previously adopted Staff's cash-basis methodology (May 2, 2019 Order in Case No. U-20162, p 87), but maintains that it has an inherent flaw because the net write-offs do not have a direct correlation with the revenues used to calculate the ratio in any given year. There is a significant timing lag between revenue recognition and when the net write-offs occur. Another notable flaw is that the ratio is applied to the Company's present revenues rather than projected revenues, which will not be known until the conclusion of this case (6T 1144-45, 1151-52).

Ms. Uzenski further explained that the cash basis method of estimating uncollectible expense is inconsistent with how expense is recorded and with how other costs and revenues are calculated for both MPSC reporting and for ratemaking. The estimation of future expenses should be consistent with the practice used to record the actual expenses to ensure recovery of the Company's reasonable and prudent costs. An average of the amounts charged to account 904 provides such consistency. Moreover, Staff's methodology in this case is not consistent with the method approved in Case No. U-20162. If the cash basis method is to be used (which it should not be), then it should at least be applied consistently. Exhibit A-40, Schedule EE1 makes the necessary

technical corrections, changing Staff's originally-filed uncollectible expense of \$46.8 million to \$52.4 million (6T 1563-65).

The Commission directed the Company to provide information in this case on the reduction in uncollectible expense attributable to credit card payments (May 2, 2019 Order in Case No. U-20162, p 85). Accordingly, Ms. Johnson reported that the Company analyzed a 5-month period (September 2018 to January 2019) for customers once they entered final arrears. Approximately \$1.9 million of payments went from a non-credit card method of payment to the credit card method of payment (6T 1148).

Mr. Coppola proposed a \$2.1 million uncollectible expense reduction based on this study, which he calculated by just annualizing the \$1.9 million for 5 months to \$4.6 million for 12 months, and then multiplying that by the 46% increase in merchant fees from 2018 to the projected test year (9T 3058-60). Ms. Johnson explained that the AG's calculation is implicitly based on the inaccurate assumption that utilizing a debit or credit card is a new offering to customers. Instead, the effect of customers using debit and credit cards is already embedded in the projected uncollectible expense. The AG's methodology is also flawed because the projected change in residential merchant fees is associated with the total population of customers who are projected to use credit cards for payment, rather than customers who will be uncollectible. The AG essentially proposes an unsound method to double-count something that is already captured, so it should be rejected (6T 1152-53, 1164-65). Thus, the Company's proposed uncollectible expense amount of \$51.6 million should be adopted.

9. Regulated Marketing O&M Expenses

Regulated Marketing had \$11.6 million of O&M expense for the 2018 historical test year (6T 1039-40; Exhibit A-13, Schedule C5.9, column (c), line 15). This expense included Major Account Services, Electric Marketing, Economic Development, Demand Response (DR) costs, and

amortization of plug-in electric vehicle pilot costs (6T 1040). DTE Electric seeks to recover \$14.7 million in the projected test year (6T 1041; Exhibit A-13, Schedule C5.9, column (k), line 15). The increase is due to known and measurable changes of \$0.7 million for inflation; \$67,000 for DR portfolio expenses; \$0.9 million of Fixed Bill Pilot expenses (see section XI. C. 3); \$0.6 million for Charging Forward regulatory asset amortization (see section VI. I); and \$0.8 million for Low Income Renewables Pilot expenses (see section XI. C. 2). (6T 1040). The projected expense of \$10.6 million (as reduced for the \$1 million Charging Forward asset amortization) is a reasonable and prudent level necessary to support the new 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 (6T 1041).

10. Corporate Staff Group O&M Expenses

The Corporate Staff Group's (CSG) O&M expenses (excluding employee benefit costs, and after rate case adjustments and normalizations) as allocated to DTE Electric were \$182.8 million for the 2018 adjusted historical test period, and are expected to increase to \$183.6 million for the projected period ending April 30, 2021 (6T 1519-20; Exhibit A-13, Schedule C5.10, line 21, 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 last eight general rate cases (Case Nos. U-13808, U-15244, U-15768, U-16472, U-17767, U-18014, U-18255 and U-20162) as well as DTE Gas's general rate cases going back over a decade to the Commission's Order issued April 28, 2005 in Case No. U-13898 (6T 1520-22).

The Company projected \$12.9 million of Injuries and Damages (I&D) expense using the traditional five-year (2014-2018) average. Staff proposed a \$1.6 million reduction based on a four-year (2014-2017) average, excluding 2018 on the purported basis that it had “unusually high” I&D expense (9T 3278-79). Ms. Uzenski disagreed, first explaining that 2018 was not “unusually high” at \$19.3 million. Past averages have included a single year expense of over \$20 million in the calculation. Normalizing fluctuations in annual expense is the reason that a five-year average has been used in the first place. It is not appropriate to change methodologies to get a desired result in individual cases (6T 1559, 1562-63). As Ms. Uzenski explained, the Commission has approved a five-year average of injuries and damages expense in DTE Electric’s last seven rate cases: U-20162, U-18255, U-18014, U-17767, U-15244, U-15768 and U-16472. (6T 1563)

In Case No. U-20162, the AG similarly proposed a three-year average to exclude 2013’s relatively-high expense from the calculation, which would have reduced the test year projection by \$1.9 million. The Commission observed that “Staff agreed with the use of a five-year average because injuries and damages tend to be ‘volatile and difficult to project.’ 8 Tr 4028” (May 2, 2019 Order in Case No. U-20162, p 89). The Commission rejected the AG’s proposal, explaining that it was “not persuaded that \$5 million in increased expense in one of the five test years (2013) is sufficient reason to shorten the five-year time frame to three years such that 2013 is excluded. The Commission agrees with the ALJ’s reasoning that the purpose of a longer time frame is to normalize expenditures” (*Id*, p 90). “Cherry picking” selective data also threatens an illegal result.⁶⁴ Therefore,

⁶⁴ The Michigan Supreme Court cited with approval the conclusions of a circuit court judge granting an injunction against such unlawful rates: “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.” *Michigan Consolidated Gas Company v Public Service Comm*, 389 Mich 624, 633; 209 NW2d 210 (1973).

the Commission should continue its past practice, approve the Company's recommendations regarding injuries and damages expense, and reject all contrary recommendations.

ABATE witness Mr. Dauphinais questioned DTE Electric's corporate memberships and indicated a concern that customers might be subsidizing political activity (7T 1684-88). Ms. Uzenski alleviated these concerns by explaining that Exhibit A-40, Schedule EE2 provides a list of corporate memberships included in the Company's revenue requirement, and the benefits that those associations provide. Memberships in organizations that provide key operational support are allowed for ratemaking purposes. All other corporate memberships are excluded. Any dues paid to advocate for legislation or other political activity are recorded to account 426.4, Expenditures for Certain Civic, Political, and Related Activities, which is excluded from base rates (6T 1565).

Ms. Uzenski further explained DTE Electric's careful review process, and conservative exclusion of certain items from the Company's requested rate recovery (6T 1611-14). Her additional scrutiny also revealed two small items that should be removed from DTE Electric's rate request in this case: (1) \$4,000 that should have been recorded to DTE Gas (6T 1609-10); and (2) an additional \$281,175 (6T 1616). With the adjustments for the correction of corporate members as discussed above, Corporate Staff Group O&M expense should be \$183.3 million (\$183.6 million less \$0.3 million).

11. Employee Pension and Benefits Expenses

DTE Electric projects \$172.2 million of employee pension and benefits costs, which after adjustments for the portion of these costs capitalized, transferred and eliminated as being related to separate surcharge programs, results in a net employee pension and benefits O&M expense of \$156.9 million for the projected test year (5T 910-11; Exhibit A-13, Schedule C5.11).

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 cost: This represents the pension benefits earned by active employees during the current period on a present value basis. It is based on actuarial assumptions including current and projected salaries, expected employee turnover, and life expectancy.

Interest cost: 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 4.40% for the historical period, and 4.40% 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 2017, the prior fiscal year end, and projected benefit payments from the pension plan matched against a yield curve of corporate bond rates, rated Aa or higher, provided by DTE Electric's independent actuarial firm, Aon Hewitt. The 4.40% discount rate for the projected period reflects an expectation that high-quality corporate bond interest rates at the end of 2020 will remain essentially unchanged from levels prevailing in December 2018.

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 7.50% for the historical period and is reduced to 7.30% in 2019.

Amortizations: In addition to these current period costs, pension costs also include the effect of the delayed recognition of prior costs. This includes prior service costs and unrecognized gains and losses. Prior service costs arise from pension plan changes that will affect future economic benefits for employees. Unrecognized gains and losses are changes in the amount of either the PBO or plan 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 arise whenever discount rates or actual asset returns differ from long-range expectations (5T 894-97).

DTE Electric's annual pension costs are expected to decrease from \$108.9 million in the historical test period to \$75.3 million in the projected period, or \$50.7 million inclusive of the effects of costs capitalized and transferred (5T 897-98; Exhibit A-13, Schedule C5.12.1).

ii. Other Post-Employment Benefit (OPEB) Expenses

DTE Electric's 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 expected return on assets invested to meet the future liabilities, the interest cost on the accrued liability, and the amortization of unrecognized gains and losses (5T 898-900).

DTE Electric's OPEB costs are projected to decrease from a negative \$16.6 million in the historical test period to a negative \$17.6 million in the projected period, or negative \$11.9 million

inclusive of the effects of costs capitalized and transferred (5T 900; Exhibit A-13, Schedule C5.12.2).

The Commission approved the Company proposal to defer negative OPEB expense to a regulatory liability (December 11, 2015 Order in Case No. U-17767, p 69), and to continue that deferral (January 31, 2017 Order in Case No. U-18014, pp 94-95; April 18, 2018 Order in Case No U-18255, p 34, n 8; May 2, 2019 Order in Case No. U-20162, p 91). The Company proposes a continuation of the OPEB deferral until the regulatory liability fully absorbs any future OPEB expense, with any resulting debit balance to be reviewed in a subsequent rate case. 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 (5T 902-903).

iii. Active Healthcare Benefits

DTE Electric incurs substantial costs to provide healthcare benefits to its active employees. Active healthcare costs, inclusive of life insurance and benefit plan administrative fees, are projected to increase from \$43.6 million in the historic period, to \$60.1 million in the projected period. This increase reflects the normalization of medical expenses for a one-time credit recognized in 2018. The increase also reflects the net medical trend of 5.5% in 2019 and 2020, and 5.0% in 2021, as adjusted for expected impact of the Company's enhanced Wellness program, as described below. The annual unadjusted medical trend factors of 5.50% for 2019 and 6.00% for 2020 and 2021 are based on a rigorous analysis of healthcare cost trends provided by the healthcare experts at Aon Hewitt, as reflected on Exhibit A-13, Schedule C5.11.1.⁶⁵

⁶⁵ These projections are corroborated by a study released in 2019 by PriceWaterhouse Coopers LLP's (PWC) Health Research Institute, which projects that medical costs will increase 5.7% in 2019 and 6.0% in 2020 (5T 906; Exhibit A-13, Schedule C5.11.2)

iv. Other Employee Benefit Costs

The Company's Other Employee Benefits are projected to be \$8.7 million (Exhibit A-13, Schedule C5.11, line 28). These costs include a variety of other benefits including Accrued Vacation, Supplemental Severance Plan, Long-Term Disability claims, costs associated with the Affordable Care Act (ACA), General Benefits expenses, the Company's Wellness Program, as well as the Supplemental Savings Plan and Deferred Compensation Plan, and are supported in Mr. Cooper's testimony (5T 906-10).

Included in Mr. Cooper's projection of Other Benefits expense was an expansion of the Company's Wellness program that is designed to produce significant reductions in future active healthcare expenses through the creation of a culture of health well-being within the Company. Mr. Cooper projected the enhanced Wellness program would result in an increase of the Wellness program expense from \$2.2 million to \$4.5 million (5T 908).

Mr. Coppola proposed to disallow \$2.3 million of the \$4.5 million relating to the Company's enhanced Wellness program, claiming that it was not supported sufficiently (9T 3063-64). In rebuttal, Mr. Cooper disagreed with Mr. Coppola's proposal, by detailing that the initial focus of the enhanced Wellness program would be the three highest-risk health factors for the Company's employees (obesity, hypertension, and high blood sugar), with an expanded focus on injury prevention (5T 961, 972). Mr. Cooper also explained that the enhanced Wellness program was the basis for assuming that the active healthcare trend rates supplied by Aon were reduced by 0.5% in 2020 and 1.0% in 2021 that were used in the development of projected active healthcare costs, as described above. This assumption that the enhanced Wellness program would produce reductions in the rate of increase in active healthcare costs was informed by extensive research demonstrating that wellness programs are a cost-effective means of reducing the rate of increase in employee

healthcare costs (9T 962; Exhibit A-33, Schedule X3). Mr. Coppola also ignored that the Company projected lower active healthcare expense due to savings from the Wellness program. Therefore, if Mr. Coppola's proposal were to be adopted (which it should not be), then projected active healthcare expenses should be increased by \$483,000 for the projected test year (5T 963).

12. Employee Compensation

DTE Electric's overall employee compensation philosophy is to provide pay programs that (1) attract, retain, and motivate employees; (2) ensure that pay is externally competitive; and (3) differentiate total rewards based on both organizational unit and individual contributions and results (5T 912). 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. Mr. Cooper provided a detailed description of the design and mechanics of these plans (5T 912-47; Exhibit A-21, Schedules K4, K5, K6, K7 and K8 Revised). In addition, in response to a Commission directive contained in its Order in Case No. U-20162, Mr. Cooper also provided additional detail related to the reasonableness of the Company's compensation practices relative to market and an historical analysis of the Company's actual annual operating measure performance levels relative to annual goals (5T 919, Exhibit A-21, Schedules K1, K2 and K3 Revised. See also May 2, 2019 Order in Case No. U-20162, p 94).

DTE Electric seeks to recover the \$47.6 million net projected test period incentive compensation expense, which excludes the expense allocated to the Company for DTE Energy's

top five executives (5T 917-18, 938; Exhibit A-21, Schedule K8 Revised, line 69, column (k)). The performance measures included within the plans include 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.

	<u>LTIP</u>	<u>AIP</u>	<u>REP</u>	<u>Total</u>
Financial	\$16.8	\$3.0	\$8.7	\$28.4
Operating	\$0.0	\$4.6	\$14.6	\$19.2
Total	\$16.8	\$7.6	\$23.2	\$47.6

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. Within Customer Satisfaction are measures related to improving performance as measured by the J. D. Power National Peer Set. Also included are measures related to improving customer service and reducing complaints to the Commission. Employee Engagement measures pertains to creating a highly motivated and productive workforce as well as improvements related to workplace safety. Operating Excellence includes measures related to reducing the length of service interruptions, fossil and nuclear power plant reliability as well as additional specific measures related to the nuclear generation business unit. The Operating Excellence measures used at DTE Energy Corporate Services LLC were adjusted to exclude measures to DTE Gas (5T 929-35, 939, 942-47).

Exhibit A-21, Schedule K3 Revised reflects a summary of the Company's actual annual performance relative to the annual Thresholds, Targets, and Maximums for the Operating measures

in the Company's incentive compensation plans for 2014 through 2018.⁶⁶ It shows that the average of the annual operating performance results for 2014 through 2018 was 92.0% for the AIP and 79.9% for the REP. This demonstrates that on an annual effective average basis, the Company is performing very near to target levels (5T 924).

Staff proposed to exclude \$28,437,000, representing incentive compensation expense related to financial measures (9T 3282), indicating that it understood recent decisions by the Commission to have established a "policy" of excluding financial performance measures from the revenue requirement (9T 3281). To the contrary, the Commission has based its decisions on the evidence (*e.g.*, April 17, 2018 Order in Case No. U-18255, p 49) and has expressly recognized that "each case must be evaluated on the record in that case" (January 31, 2017 Order in Case No. U-18014, p 85).⁶⁷ Thus, financial measures have not been, and cannot lawfully be, categorically disallowed as Staff suggests.⁶⁸

Mr. Coppola proposed the complete elimination of incentive compensation expense related to financial measures (\$28.4 million), plus 50% of incentive compensation expense related to operating measures (\$9.6 million) for a total disallowance of \$38.0 million (9T 3071-72). Like Staff, the AG's proposed exclusion of financial measures is based on a broad policy viewpoint that these measures benefit only shareholders and not customers (9T 3066).

⁶⁶ The 2019 AIP and REP measures and ratings are reflected on Exhibit A-21, Schedules K4 through K6 (5T 928-29).

⁶⁷ 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 (November 19, 2015 Order in Case No. U-17735, pp 73-74, 78).

⁶⁸ 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.

The proposed exclusion of the incentive compensation expense related to financial measures does not consider that there are substantial customer benefits related to financial measures as reflected on Exhibit A-21, Schedule K8 Revised and further explained by Mr. Cooper. Financial metrics do not simply benefit shareholders. Instead, customers benefit from incentive compensation measures that focus on earnings cash flow measures because the ability to exceed the annual goals is dependent on the Company realizing productivity enhancements and cost savings, which allows the Company to postpone rate increases and produces lower revenue requirements when rate increases become unavoidable. The beneficial impact of the cost and productivity focuses of the earnings and cash flow measures is illustrated by the fact that the Company's O&M expenses have increased by less than inflation from 2009 through the end of the projected test year. Specifically, the Company's projected O&M expense as filed for the projected test year is \$221.6 million less than it would have been if the Company's 2009 O&M expense increased by the rate of inflation (5T 941). DTE Electric's financial performance also directly affects its ability to raise capital, as well as the cost of capital, that it needs to fund its operations. Accordingly, the costs of encouraging managers and employees to provide excellent customer service with an eye on the financial bottom line is fully justified. Furthermore, DTE Electric's shareholders are also sharing in the incentive compensation expense, since the Company's proposed recovery does not include \$10.5 million of incentive compensation expense for the top five executives (5T 917-18, 940-42, 951-52, 955-56; Exhibit A-3, Schedule C-20, Exhibit A-21, Schedule K8 Revised).

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 as DTE Electric provided an in-depth cost/benefit analysis demonstrating a \$51.2 million net customer benefit

(\$98.8 million total customer benefits minus \$47.6 million total incentive plan costs) (5T 940; Exhibit A-21, Schedule K8 Revised, line 69).

It is also important to recognize that certain metrics can provide benefits to customers, while evading specific quantification. There can be little doubt that an emphasis among the Company's leadership and employees on improving the customers' experiences with the Company results in significant non-quantifiable benefits to both customers and the Commission (5T 940-46).

Incentive compensation programs are an increasingly prevalent practice among the vast majority of energy companies.⁶⁹ Therefore, DTE Electric must also offer incentive compensation opportunities to be competitive with other employers in attracting and retaining talented and qualified employees (5T 918-26). The record further demonstrates that DTE Electric's incentive compensation programs allow the Company to attract and retain employees at a reasonable cost relative to its peer companies. There is no evidence from any party in this case upon which the Commission could determine that the *total* annual compensation of DTE Electric employees is unreasonable or imprudent. Further, the focus on the variable portion of total compensation is also inappropriate because DTE Electric's incentive programs are not additional compensation over and above what other companies pay for similar jobs. Instead, DTE Electric's incentive compensation programs are one of two components that make up DTE Electric's total annual compensation package, which is comparable to other companies competing for the same employees (5T 912-13).

This point bears emphasis because the Commission has repeatedly denied incentive compensation expense related to financial measures, while apparently overlooking the

⁶⁹ A 2014 WorldatWork and Deloitte Consulting study indicates that in 2013, 99% of companies had short-term incentive programs and 88% had long-term incentive programs in 2013, up from 95% and 61%, respectively, in 2011 (5T 926).

reasonableness of total compensation. DTE Electric's analysis of virtually all incumbent salaries as of December 31, 2018 shows that the Company's compensation is lower than market medians for base compensation and total compensation (5T 919-21; Exhibit A-21, Schedule K1).⁷⁰ Moreover, without the Company's short-term incentive compensation programs, the Company's pay would be 13.0% less than the market medians (5T 922, 952).

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 (5T 951).

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 (5T 913-15).

Staff further proposed the disallowance of \$4.063 million of Restricted Stock expense, reasoning that it relates to the achievement of financial performance measures (9T 3282). Mr.

⁷⁰ Aon reviewed the data and techniques used by the Company, and concluded that the Company used best practices in sourcing the market pay data and developing estimated market values (5T 923-24; Exhibit A-21, Schedule K2).

Cooper explained that Staff's proposal is based on an incorrect inference. Staff apparently relied upon a phrase from the Company's LTIP employee plan description book (Exhibit S-3.6, indicating that the LTIP is "a reward to employees for assisting the Company in reaching its financial performance goals") as inferring that Restricted Stock relates to financial measures. Instead, the LTIP has two components (Performance Shares and Restricted Stock). The quoted phrase relates to Performance Shares, which are granted annually with the number of shares distributed dependent on the Company's performance relating to certain financial measures, as detailed on Exhibit A-21, Schedule K7. In contrast, Restricted Stock (which is accurately calculated as \$3.670 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 (5T 953-55).

Mr. Coppola observed that of the \$51.2 million in net customer benefits reflected in Exhibit A-21, Schedule K8 Revised, the largest net benefits are related to Financial Measures (\$6.3 million) and Operating Excellence (\$50.3 million). He further asserted that Operating Excellence "is highly dependent upon a more aggressive tree trimming and capital spending program," and concluded: "It is added spending that is creating these benefits for the most part (not an employee bonus program) and the cost of such capital is not a factor in this analysis" (9T 3069). Mr. Cooper disagreed that Operating Excellence benefits are unrelated to the Company's incentive compensation programs. While the Company's spending levels are one prerequisite for achieving improvements in distribution system reliability, the Company's employees will need to effectively deploy and manage the improvement programs (5T 957).

Mr. Coppola proposed to exclude 50% of incentive compensation expense relating to operating measures, asserting that “[a]s reflected in Exhibit AG-1.39, the Company’s failure rate related to achieving its non-financial goals was at the 71% level in 2018 (excluding nuclear operations).” (9T 3070). Mr. Cooper explained that Mr. Coppola’s calculation was inaccurate for three reasons. First, it reflects only REP results rather than both REP and AIP results. Second, it ignores Nuclear Generation results. Third, it incorrectly subtracts from the total number of Operating measures identified on Exhibit A-21, Schedule K3 Revised the number of Financial measures, which are not included on Exhibit A-21, Schedule K3 Revised. Simply correcting Exhibit AG 1.39 (its methodology is still invalid), shows that contrary to Mr. Coppola’s claim that only about 30% of the measures had above-Threshold performance in 2018, in fact over 70% were at Threshold or above (5T 958; Exhibit A-33, Schedule X2).

Mr. Coppola also neglected to consider that while certain measures may produce results less than Threshold, other measures can produce results greater than Threshold. Exhibit A-21, Schedule K3 Revised shows that from 2014 through 2018, the actual weighted performance was 92.0% for the AIP and 79.9% for the REP (5T 958-59).

This average annual performance method is more accurate than Mr. Coppola’s binary approach (either the target was met, or not), and it recognizes that actual payouts can fall within a wide spectrum. Moreover, variations in year-to-year performance further reflect the ambitious goals set each year to motivate ever-improving operating performance. It is not reasonable to assume that only 50% 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 (5T 959-60, 969).

The Commission previously relied on similar evidence to reject essentially the same argument that the AG repeated in this case. The Commission instead authorized DTE Electric's recovery of incentive compensation relating to operating measures, explaining in part: "The Commission notes that DTE Electric provided evidence showing that the company has achieved performance targets for AIP at an average of 96.3% and for REP at an average of 82.8%, from 2012 to 2016. (7T 837). When looking at historical performance over a longer period, the Attorney General's recommendation that 50% should be disallowed is simply not supported" (April 18, 2018 Order in Case No. U-18255, p 49). The Commission's older orders also recognize that incentive compensation is 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.⁷¹

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 of the Company's incentive compensation expense (except for the top five DTE Energy executives) in the revenue requirement adopted in this case.

⁷¹ The Commission long ago recognized that: "Executive bonuses have often been viewed as an appropriate cost of operating a utility" (October 28, 1993 Opinion and Order in Case Nos. U-10149 and U-10150, p 57 (rejecting the ALJ's total exclusion recommendation; adopting Staff's 50/50 sharing proposal; and advising DTE Gas that "future approval of an incentive bonus plan like this requires a showing that it will not result in excessive costs and that the benefits to the utility's ratepayers will be commensurate with those costs"). See also, for further example, Case No. U-17767, where the Commission approved DTE Electric's recovery of costs attributable to operating measures, stating that:

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

Mr. Coppola further proposed to disallow \$44 million of capitalized incentive compensation for 2018 through the end of the projected test year, asserting that “[t]hese amounts reflect the Commission’s prior decisions to allow recovery of only incentive compensation pertaining to operating measures for the short-term incentive plans and no recovery for long-term incentive compensation” (9T 3007, 3073).

Ms. Crozier disagreed with Mr. Coppola’s proposal, as well as his reasoning that such amounts have previously been excluded from rate base. As discussed above, incentive compensation is a primary part of DTE employees’ overall compensation. As such, a portion has historically been included in plant as well as O&M. The Commission previously disallowed a portion of incentive compensation included in O&M expense, but not incentive compensation that has been capitalized. Mr. Coppola’s proposal should be rejected because it would be a significant departure from past ratemaking treatment, and result in a plant balance that does not reflect the full cost incurred by the Company. Moreover, if the Commission were to make such a change (which it should not do), then the change should be prospective only (applying after the date on which rates approved in this case become effective). Otherwise, the Company would incur significant write-offs relating to costs that had previously been incurred and approved for inclusion in rates by the Commission (4T 504-505).

D. Depreciation and Amortization

DTE Electric seeks to recover \$949.6 million of depreciation and amortization (D&A) expense for the projected test period (Exhibit A-13 Schedule C6). Ms. 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-16117 for the historical period through April 2019. The projected period was calculated using rates as approved in Case No. U-18150, which became effective with the May 2, 2019 Order in Case No. U-20162 (6T 1503).

The projected \$213.6 million D&A increase was due primarily to \$108 million for the change in depreciation rates, \$166 million for capital in-service movement, and \$7 million related to amortizable general plant. The increase is partially offset by approximately \$62 million for plant retirements (including \$2.5 million related to St. Clair Unit 1) and \$5 million from the CTA and DTE2 regulatory assets being fully amortized before the projected test period (6T 1514).

As discussed in Section I, the Company has now made a \$17.8 million reduction to its capital projections. This reduction correspondingly reduces the Company's projected D&A expense by \$0.4 million. These adjustments result in a revised projected D&A amount of \$949.2 million. The Company's projected D&A expense of \$949.2 million is reasonable and should be approved by the Commission.

E. Property and Other Taxes

DTE Electric seeks to recover \$279.6 million of property tax expense for the May 2020 through April 2021 projected test period (9T 3570; Exhibit A-13, Schedule C1, column (e), line 6). This amount is calculated by taking 8/12ths of the 2020 calendar year expense, plus 4/12ths of the 2021 calendar year expense (9T 3571).⁷²

⁷² The projected 2019 property tax liability is \$286.1 million (9T 3568; Exhibit A-13, Schedule C7.1, column (c), line 54). The projected 2020 property tax liability is \$311.9 million (9T 3568; 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 (9T 3563, 3568, 3570-71).

DTE Electric projects a \$52.1 million Other Tax Expense for the projected test year, consisting of payroll taxes (\$39.0 million), Public Utility Assessment fees (\$12.8 million), and miscellaneous other taxes (\$0.3 million) as shown on Exhibit A-13, Schedule C7, column (j), lines 2-5 (9T 3573).

F. Income Tax Expenses

DTE Electric seeks a total income tax recovery of \$87.0 million (9T 3572). DTE Electric projects a \$43.5 million federal income tax (FIT) expense for the projected test year, based on a 21% FIT rate (W 4, 13; Exhibit A-13, Schedule C8, line 58). DTE Electric projects a \$41.2 million Michigan Corporate Income Tax (MCIT) expense, based on a 5.88% rate (9T 3563, 3573; Exhibit A-13, Schedule C9, line 15). DTE Electric projects a \$2.2 million municipal income tax expense, based on a 0.33% composite municipal income tax rate (9T 3563, 3574; Exhibit A-13, Schedule C10, line 11).

Ms. Wisniewski further explained that overall methodology for amortizing the Tax Cuts and Jobs Act (TCJA) tax regulatory liability for excess deferred taxes (reflected in Exhibit A-13, Schedule C8.1) is consistent with the May 2, 2019 Order in Case No. U-20162. Amortization for the May 2020 through April 2021 test period reduces tax liability by \$60.1 million (9T 3474-75; Exhibit A-13, Schedule C8, line 54).

IX. OTHER REVENUE RELATED ISSUES

A. Accounting Requests

As discussed in section VIII. C. 4 (regarding Fermi 2 O&M Expenses), the Company requests an increase in the Program Evaluation & Review Committee (PERC) base to \$15 million for the PERC deferral mechanism. The Company also requests the continuing deferral of net OPEB expense to a regulatory liability, as discussed in section VIII. C. 11 (regarding Employee Pension

and Benefits Expenses). Further, as explained by Ms. Uzenski and discussed above, the Commission should also authorize the Company to defer as a Regulatory Liability or Asset any difference between the Company's actual net pension expense and \$50.7 million in recognition of the inherent variability of pension expense arising from current volatility in the financial markets (6T 1570).

Ms. Uzenski further explained that the FASB issued Accounting Standards Update (ASU) 2018-15, Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract. The ASU is effective January 1, 2020 and is consistent with the Company's existing policy for cloud service implementation costs in terms of capital or expense treatment; however, the ASU requires classification of any deferred costs in Other Assets (like prepayments) instead of Plant in Service. Since the implementation costs at issue must be classified in Other Assets for SEC reporting, the Company requests the Commission's approval to record the deferred costs in PP&E and recognize the expense as amortization for MPSC reporting, consistent with current practice (6 T 1556-67).

X. SUMMARY OF REVENUE DEFICIENCY AND REQUESTED RATE RELIEF

Based on the adjustments described above in Section I, **DTE Electric supports and requests approximately \$ 343.0 million in rate relief.** See Attachments A and B.

XI. COST ALLOCATION AND RATE DESIGN

A. DTE Electric's Cost of Service Study Supports the Company's Rate Design Proposals

Mr. Lacey developed and supported Unbundled Cost of Service (UCOS) studies for DTE Electric's projected test year ending April 30, 2021, which are consistent with past practice, including the cost-allocation methods approved in Case No. U-20162 (7T 2014, 2019, 2025; 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);⁷³ (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' responsibility for the incurrence of these costs). (7T 2015).

The UCOS study contains 16 basic externally-developed allocation schedules (7T 2020). Mr. Brasil developed 11 allocation schedules for use in cost-of-service studies (see Exhibit A-5, Schedule E3 for a description of each schedule). He supported these allocation schedules as reasonable and as accurately representing the load characteristics for customers receiving power supply and/or distribution service from DTE Electric (8T 2324, 2328). Mr. Lacey used Mr. Brasil's allocation schedules, plus five more that he developed himself, to determine rate class cost responsibility (7T 2020).⁷⁴

Mr. Lacey explained how he functionalized DTE Electric's costs (7T 2016-19; Exhibit A-16, Schedule F1.3), and how the UCOS allocates costs to DTE Electric's various customer classes (7T 2019-21). He further testified that DTE Electric will experience a jurisdictional revenue deficiency of approximately \$350.7 million in the year ending April 30, 2021, consisting of a \$165.4 million total production revenue deficiency, and a \$185.2 million distribution revenue deficiency. Exhibit A-16, Schedule F1.1 shows the production-related revenue (sufficiency)/deficiency

⁷³ 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 (7T 2016).

⁷⁴ Mr. Jester recommended "that the Commission direct that in all future cases DTE Electric treat outflows as offsetting inflows for each customer class in the computation of allocation factors" (9T 3825). Mr. Brasil responded that the systems currently in place are not designed to capture outflows when calculating load factors, but the Company will explore and consider a modification for the next rate case, to include outflows in its system used to compute allocation factors (8T 2332).

associated with each consolidated rate class. Exhibit A-16, Schedule F1.2 shows the distribution-related revenue (sufficiency)/deficiency by voltage level (7T 2023-24).

Mr. Lacey proposed to continue using the same allocation methods for transmission and production that were approved in the May 2, 2019 Order in Case No. U-20162 (7T 2019). He further explained that DTE Electric uses three allocation bases for distribution: demand, customer, and those based on special studies.⁷⁵ 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 Signals⁷⁶), consistent with the allocation method that the Commission approved in Case No. U-20162 (7T 2026). Exhibit A-16, Schedule F1.4 calculates monthly customer charges by voltage level, using the Staff method approved in the May 2, 2019 Order in Case No. U-20162 (7T 2028-29).

Exhibit A-16, Schedule F3 shows present and proposed revenues by rate schedule. Exhibit A-16, Schedule F4 calculates typical bills for each rate schedule based on the Company's present and proposed rates. Exhibit A-16, Schedule F8 contains the proposed rule and tariff sheet changes. Further detail on customer-related costs by rate class is provided in Exhibit A-16, Schedule F1.4, as indicated above and further discussed below in the context of the specific proposals.

⁷⁵ 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 (7T 2026-27).

⁷⁶ Distribution classes related to lighting are maintained as separate classes because they have a significant amount of dedicated infrastructure costs that are required to be assigned directly (7T 2026).

The Commission adopted the 4CP 75-0-25 method for allocating certain production costs⁷⁷ in Case No. U-17689 (in accordance with 2014 PA 169), and has continuously applied it in subsequent DTE Electric rate cases, Case Nos. U-17767, U-18014, U-18255, and U-20162. The Commission most-recently reminded future parties of the standard “that any party proposing to revise the production cost allocation method in a future case include in its evidentiary presentation an analysis using the equivalent peaker method or an approximation for comparison purposes” (May 2, 2019 Order in Case No. U-20162, p 129, quoting the January 31, 2017 Order in Case No. U-18014, p 100).

Mr. Jester disagreed with the 4CP 75-0-25 production cost allocation method, and developed three alternative methods that would shift costs from residential customers to other customers, based on the testimony and exhibits of witnesses Boothman, Bunch, and Gard (9T 2825-41). Mr. Jester recommended that “the Commission in this case shift revenue responsibility away from that proposed by DTE at least as far as results from application of the Equivalent Peaker 4CP method, which would also begin a gradual change in revenue responsibility” (9T 3840).

Ms. Crozier explained that Mr. Jester’s recommendation should be rejected for three reasons. First, the Legislature and the Commission have been on a consistent path toward the alignment of costs with causation since the passage of 2008 PA 286, which abandoned Michigan’s prior rate-skewing policy through which commercial and industrial customers subsidized residential customers. MCL 460.11(1) relevantly provides: “Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of

⁷⁷ The only production costs allocated using 4CP 75-0-25 are plant and plant-related costs. Other production costs are allocated differently or assigned directly (7T 2037).

providing service to each customer class.” To reverse course now would erode a decade of deliberate, and legally-required,⁷⁸ moves intended to ensure that rates are equal to the cost of service. Second, there are numerous technical errors in the alternative methodologies and supporting calculations, as further discussed below. Third, the most recent legislation, 2016 PA 141, codifies the 75-0-25 method, and sets forth a standard that witnesses Jester *et al* do not meet in their cost-shifting suggestions (4T 497-500).⁷⁹ Staff similarly supported retaining the current 4CP 75/0/25 methodology (9T 3256-57, 3259).

Mr. Lacey further explained that all three alternative methods are flawed and should be rejected because: (1) none of the methods is an equivalent peaker method as described in the NARUC Cost Allocation Manual (NARUC Manual); (2) all of the methods incorrectly allocate *all* production costs, not just plant-related production costs; (3) all of the methods have errors in their underlying calculations; and (4) the methods produce wildly different results that further undermine every method’s credibility (7T 2038, 2046).

More specifically, the first method, which Mr. Jester called the Probability of Dispatch (POD) method, would (among other things) shift over \$185 million of revenue requirement to the Company’s primary customers (9T 3840). Mr. Lacey disagreed with the suggested use of the POD method, noting two significant concerns. First, it is not an equivalent peaker method. The NARUC Manual includes the equivalent peaker method with Energy Weighting methods, and the POD

⁷⁸ MCL 460.11(1) uses the term “shall,” which denotes a mandatory duty imposed by the Legislature and excludes the idea of administrative discretion. *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”).

⁷⁹ MCL 460.11(1) relevantly states: “The Commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service.”

method with Time Differentiated methods. Therefore, it does not satisfy the Commission's above-quoted standard. Second, Mr. Lacey identified several errors in the POD method calculations, and discussed the improper allocations in Mr. Boothman's COSS (which is Exhibit MEC-70). (7T 2039-41). To demonstrate how Mr. Boothman improperly allocated revenues, Mr. Lacey developed Exhibit A-36, Schedule AA2, which shows that "under the POD method residential customers were under allocated revenues by \$124 million," and indicates that MEC's other proposed production cost allocation methods were similarly misaligned (7T 2041-42).

The second method, which Mr. Jester called the Equivalent Peaker 4CP (EP4CP) method, would (among other things) shift about \$42 million of revenue requirement from residential to primary customers (9T 3839). Mr. Lacey disagreed with the suggested use of the EP4CP method, explaining that by allocating all production rather than just plant-related costs, the method totally ignored the capacity charge calculation mandated by the Commission (7T 2042-43).

Ms. Crozier further explained that the Company properly calculated a capacity charge revenue requirement (which is further discussed in subsection B below) using the same methodology approved by the Commission in its May 2, 2019 Order in Case No. U-20162 (4T 500). Staff agreed that the "Company's capacity revenue requirement method is consistent with the method ordered by the Commission in U-20162" (9T 3249). In contrast, Mr. Bunch performed a modified equivalent peaker analysis and produced a total capacity-related production cost of approximately \$948.3 million (9T 3912). This is inconsistent with the Commission's approved methodology, which in turn was based on compliance with section 6w(3)(a) and (b) of 2016 PA 341, MCL 460.6w(3)(a) and (b). Therefore, the Commission should continue to use its previously-approved methodology, and reject proposed alternative capacity charge calculation (4T 500-501).

Exhibit A-36, Schedule AA1 recalculates Mr. Jester's Exhibit MEC-66 using the Commission-approved capacity charge methodology (*i.e.*, using a \$1,543 capacity charge as properly calculated on Exhibit A-16, Schedule F1.5). Mr. Lacey explained the calculations, which result in a \$42 million reduction to primary customers and a \$42 million increase to residential customers (7T 2043-44), which essentially flips the revenue shift from the proposed EP4CP method.

Moreover, the EP4CP method is not an equivalent peaker method, so it fails to satisfy the Commission's above-quoted standard for revisiting production cost allocation. The NARUC manual describes two methods for allocating costs using equivalent peaker methods, both of which are based on the cost to build plants. The EP4CP has little in common with those methods, since it does not reflect the cost to build plants (7T 2044).

The third method, which Mr. Jester called the Equivalent Peaker Usage (EPU) method, would shift approximately \$162 million of revenue responsibility onto the Company's primary customers (9T 3839). Mr. Lacey disagreed with the use of this method because, as discussed above, by allocating all production costs rather than just plant-related production costs, the method improperly uses a flawed capacity charge calculation instead of following the Commission-approved methodology. The EPU method is also not an equivalent peaker methodology, for the same reasons discussed above regarding the EP4CP method. Mr. Boothman's calculations were also flawed, as discussed above. Thus, all three methods are deeply flawed and should be rejected (7T 2045-46).

AG witness Mr. Dismukes recommended that "the Commission modify the weighting of the existing 4 CP 75-0-25 cost allocation to one that equally weighs demand and energy concerns, or a 4 CP 50-0-50 cost allocation method," which he reasoned is "based on my analysis of what

would constitute a fair and reasonable approximation of the relative cost of service” (9T 2857). This reasoning and the resulting recommendation are flawed because Michigan law requires cost-based rates and the standard to digress from the 4CP 75-0-25 method has not been met, as discussed above regarding Mr. Jester’s proposed cost-shifting alternatives (4T 503).

Mr. Dismukes’ recommendation also lacks a sound foundation because it is based primarily on system load factors. Mr. Lacey explained that the use of system load factor is not an equivalent peaker method as described by the NARUC Manual (7T 2046-47). Mr. Dismukes suggested that Exhibit AG-2.5 presents “a close facsimile to the equivalent peaker method” (9T 2854). Mr. Lacey disagreed because the NARUC Manual describes two methods to calculate the energy/demand splits for generating units under the equivalent peaker method. The first method is based on the original cost to install the generating units. The second method compares the relative rate base cost of a peaker unit to that of a base load unit, assuming that the relative average cost difference determines the percentage of the base load unit that should be considered demand related. Exhibit AG-2.5 determines the energy/demand split in two ways. The first method uses capacity factors. The second method compares a levelized total cost to the MISO CONE price. Neither method is “close” to the methods in the NARUC Manual (7T 2047).

Mr. Dismukes further recommended that “the Commission adopt a 12 CP 100-0-0 cost allocation methodology to allocate costs associated with sub-transmission plant facilities. This would make the allocation of sub-transmission consistent with the current allocation of transmission plant” (9T 2861). The Company disagrees. Mr. Lacey first explained that Mr. Dismukes was incorrect regarding the allocation of transmission plant, which is instead included with production plant and allocated on 4CP 75-0-25, in accordance with the last seven DTE Electric rate cases. Mr.

Dismukes confused the allocation of transmission plant with the allocation of transmission O&M (7T 2036).

Mr. Lacey further explained that Mr. Dismukes' proposal should be rejected because it essentially re-functionalizes subtransmission plant from distribution to power supply, as 12CP 100-0-0 is a power supply allocator (7T 2036). Mr. Dismukes attempted to support his proposal based on the claim that "the Company's 120 kV lines, which comprise approximately 1.9 percent of the Company's sub-transmission system in mileage, are certainly closer in characteristic to transmission systems than the Company's distribution system" (9T 2860). In addition to the AG's proposal being based on just a small percentage of lines, the Commission previously recognized why 120 kV lines are on the Company's system, and specifically adopted the Company's undisputed classification proposal that "classifies distribution facilities to include the 120 kV radial lines to end-use customers as well as facilities operating at lower voltages (41.6, 24, 13.2 and 4.8 kV and secondary voltages)." (January 14, 1998 Opinion and Order in Case No. U-11337, p 3. See also, p 8). There is no basis to revisit this previously-established matter (7T 2036-37).⁸⁰

Mr. Dismukes further recommended that "the Commission allocate costs associated with demand-related secondary-voltage distribution systems based on class NCP [non-coincident peak] demands" (9T 2865). The Company disagrees that a change is either necessary or appropriate. Mr. Brasil explained that the basis for Mr. Dismukes' recommendation was not robust (18 general rate cases over an eight-year period, out of hundreds of rate cases during that period), and just because a method is used by another utility or in another state does not, in itself, justify its use for DTE

⁸⁰ See for example, *Application of Consumers Energy Co*, 291 Mich App 106, 122; 804 NW2d 574 (2010); *Pennwalt Corp v Public Service Comm*, 166 Mich App 1; 420 NW2d 156 (1988).

Electric. Mr. Dismukes did not present meaningful evidence that could support deviating from the current, well-established practice (8T 2333-34).

Mr. Dismukes further asserted that “if the Commission does not accept my proposed changes to the Company’s COSS methodology, I recommend that the Commission limit the rate increase to the residential rate class to 1.15 times the overall system average increase,” with the displaced revenue allocated to the remaining rate classes (9T 2834). The Company disagrees because the AG’s proposal would violate Michigan’s requirements for cost-based ratemaking, as discussed above (4T 501; 7T 2131). Staff similarly disagreed with the AG’s proposal (9T 3140-41).

ABATE’s Mr. Dauphinais does not contest the continuation of the 75-0-25 production plant cost allocation, although he would prefer moving to a 100-0-0 CCOSS convention. (7T 1641; 1651-1654) Based on the serious shortcomings of the AG’s and MEC/SC/NRDC/CUB’s proposals explained supra, ABATE’s non-opposition to the status quo, and the substantial effort and progress made toward achieving rates better aligned with the Company’s cost of service over the last decade, DTE Electric believes that maintaining the 75-0-25 production plant cost allocation is the most reasonable and prudent course of action and the Company’s proposals and recommendations regarding COSS should be adopted in their entirety.

B. Capacity Charge Revenue Requirement

Mr. Lacey calculated and explained the Company’s capacity charge revenue requirement, which is reflected on Exhibit A-16, Schedule F1.5 (7T 2029-32). He used the same methodology that the Commission approved in its May 2, 2019 Order in Case No. U-20162. The capacity charge revenue requirement includes all production-related costs per Exhibit A-16, Schedule F1.1, except for adjustments for fuel, certain purchase power costs, and variable O&M (7T 2029-30). Staff

agreed that the “Company’s capacity revenue requirement method is consistent with the method ordered by the Commission in U-20162” (9T 3249).

Ms. Crozier explained that there are two differences to the proposed energy market sales calculation as compared to prior cases: (1) in accordance with the May 2, 2019 Order in Case No. U-20162, the energy market revenue used is the gross energy market sales, not net energy market sales, and (2) the projected 2018 gross energy market sales, net of fuel is being trued-up to actuals with the difference netted against the 2019 projected gross energy market sales, net of fuel for use in calculating the proposed capacity charge (4T 465-67).⁸¹

More specifically, Mr. Lacey used the methodology for calculating gross energy sales net of fuel, which was approved in the May 2, 2019 Order in Case No. 20162. That Order (at pages 132-33) reflected a \$584 million reduction for energy sales net of fuel, based on a calculation originally adopted in Case No. U-18248, and invited an updated calculation using the approved method. Mr. Burgdorf recalculated this number to be \$443 million on Exhibit A-26, Schedule P3 (7T 2029; Exhibit A-16, Schedule F1.5, line 1).⁸²

Mr. Lacey 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). (7T 2030-31).

⁸¹ DTE Electric again assumes that zero Choice load will take capacity service from the Company during the projected test year, in accordance with the Staff’s March 28, 2019 report in Case No. U-20154, which found that all suppliers in Michigan, including Choice providers, had successfully demonstrated that they had the required capacity resources necessary to serve their customers through MISO planning year 2022/2023 (4T 467-68).

⁸² Mr. Burgdorf further explained the underlying calculations (5T 804-808) and summarized that the total projected 2019 wholesale energy revenue of \$1.467 billion, net of \$0.923 billion in fuel-related costs equates to \$544.1 million wholesale energy sales revenue net of fuel costs as shown on Exhibit A-26, Schedule P3, Line 26. The reconciliation of the net sales benefit difference for 2018 of \$100.8 million (Exhibit A-26, Schedule P4, Line 12, column (d)) was subtracted from the 2019 projection resulting in an amount of \$443.4 million (Exhibit A-26, Schedule P3, Line 28). (5T 808).

Mr. Lacey adjusted variable O&M (Exhibit A-16, Schedule F1.5, line 5) by including only the non-labor portions of Accounts 501 (Fuel Handling), 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 (7T 2031-32).

The resulting total capacity charge revenue requirement is \$1,543.0 million (Exhibit A-16, Schedule F1.5, line 8). Mr. Lacey allocated it to the various rate classes using the 200B (4CP) allocator excluding Rider 10, which is the methodology approved in Case No. U-20162 (7T 2032).

C. Residential Rate Design Proposals

Exhibit A-16, Schedule F3 shows the present and proposed rate design and corresponding revenue by rate schedule. Past cases have applied a 20% cap on any increase in distribution rates to the Residential Secondary class. The Company designed variable distribution rates according to this practice. The only rate schedule where the cap applied was D1.7. Exhibit A-16, Schedule F4 compares monthly bills by rate schedule based on present and proposed rates (7T 2123-25).

Soulardarity witness Mr. Koepfel asserted that “the proposed D1 and D1.6 rate schedules disproportionately impact D1.6 ratepayers” (6T 1441), and “Exhibit A-16, Schedule 4, page 9 shows the proposed rates are regressive. That is, customers using the lowest amount of energy each month are facing the highest percentage increase” (6T 1442). Mr. Dennis explained that Soulardarity’s position is incorrect because it is based on percentages that are calculated from different starting points. Rate Schedules D1 and D1.6 are exactly the same, except D1.6 customers receive a monthly \$40 special low-income discount. For example, the proposed rate increase for a 300 kWh customer would be \$4.46 on both rates D1 and D1.6. This results in an 8.34% increase

on the D1 bill, but a 33.0% increase on the D1.6 bill because the \$4.46 increase is calculated based on a starting point that is \$40 less than the corresponding D1 bill (\$13.53 for D1.6 versus \$53.53 for D1). Therefore, there is nothing unjust or unreasonable about the proposed D1.6 rates, which continue the same rate design that the Commission approved in prior cases (7T 2130-31). Staff similarly explained why Soulardarity's rate-design arguments are incorrect (9T 3144-46).

Staff proposed a residential summer on-peak (SOP) rate with an effective date of summer 2021, and that residential customers be transitioned to the new rate as the default residential rate (9T 3122-27). The Company disagrees because the Commission previously approved the Company's recommended plan, explaining in part that the "Commission believes that it is preferable to pilot multiple rates and to test multiple messages among different customer groups. The recommended plan allows the company an additional year to perform a thorough assessment and to develop a sound transitional plan for ratepayers...." (May 2, 2019 Order in Case No. U-20162, p 164). The additional year moved the implementation schedule from a 2021 target date to a 2022 target date (4T 473-74, 489-90).

The Commission also approved two of the Company's proposed pilot rates (September 26, 2019 Order in Case No. U-20602).⁸³ Those pilots are designed to inform a full rollout proposal of an advanced rate design. If the Commission were now to change course and order that Staff's proposed default rate is to be implemented in 2021, then those pilots would have no value (4T 490-91).

Staff's proposal that its residential SOP rate should be the default rate is similarly inappropriate. It would be premature to require full implementation of residential SOP rates before

⁸³ GLREA witness Mr. Richter inaccurately suggested that the Company proposed a default residential rate in its *ex parte* filing in Case No. U-20602 (9T 2793). The Company instead proposed pilots, two of which the Commission approved (4T 492).

the Company can test the impact on customers based on the pilots that the Commission approved in Case No. U-20602 (4T 491-92). The Commission also previously agreed with the Company's position on this matter, stating that "the Commission expects that the on-peak capacity (and non-capacity) rates should be tested as a combination but is concerned with establishing this as the default rate. The on-peak rates will be implemented through pilots in accordance with the implementation plan...." (May 2, 20-19 Order in Case No. U-20162, p 162).

1. Energy Assistance Initiative

Ms. Johnson outlined the goals, results, and synergies of the Company's energy assistance programs. In a further effort to assist its most vulnerable customers, the Company proposes to make the Residential Income Assistance (RIA) Provision,⁸⁴ which is currently available only to rate schedule D1 customers, available to other non-supplemental residential rate schedules. The Company also proposes to increase the funding for the Low-Income Assistance program (LIA) from \$15.4 million to \$24 million, to accommodate a projected increase of customers enrolled in the Low-Income Self-Sufficiency program (LSP). (6T 1138-42).

Accordingly, as reflected on Exhibit A-16, Schedule F8, the Company proposes to copy the RIA tariff language from rate schedule D1 to rate schedules D1.2, D1.8 and D2, which will allow customers taking service under these rates to participate in the Company's RIA program (7T 2125-26). No parties were opposed to this proposal.

Staff recommended reducing the RIA customer enrollment from 60,000 to 37,367, due to the "drastic decrease" in customer enrollments in 2018 (9T 3116-18). Ms. Johnson disagreed, explaining that the decline in customers enrolled in the RIA credit was due to defects in the C360

⁸⁴ The RIA provision provides a \$7.50 per month credit for qualifying customers, which offsets the current \$7.50 monthly service charge.

billing system, which have been corrected. Year-to-date October 2019 RIA credit enrollments dramatically increased to an average of 43,000 per month, reflecting that fixing the system quickly increased enrollments. Those enrollments can be expected to trend upward and meet the projected 60,000, so it would be unreasonable to decrease the enrollment to 37,367 as Staff suggested (6T 1153-54).

Staff further recommended keeping the LIA customer count capped at 32,000, rather than increasing it to 50,000 as the Company proposes (9T 3118). Ms. Johnson disagreed, explaining that if the cap were raised, there would be no shortage of Non-LSP low income customers enrolled in LIA and receiving the credit. The Company also disagrees that the LIA and LSP should not be paired together, since customers have the greatest success in maintaining uninterrupted service (just a 1.5% disconnect rate) when enrolled in LSP and receiving the LIA credit (6T 1155-56).

AG and MEC/NRDC/SC/CUB witness Mr. Colton recommended increasing the LIA credit from \$40 per month to \$60 per month (9T 3720). Ms. Johnson explained that the Company shares Mr. Colton's concern about bill affordability for low-income customers but does not request to just increase the LIA credit. It is important to increase the number of enrollments, so the Company can impact more low-income households. The Company stands by the success of pairing the LIA credit with the LSP program instead of just increasing the LIA credit to \$60. Disconnect rates for LSP customers receiving LIA is 1.5% compared to a 22% disconnect rate for Non-LSP customers in arrears with no credit assistance (6T 1162).⁸⁵

⁸⁵ Ms. Johnson further explained that Mr. Colton made various assertions and inferences regarding DTE Electric and its customers that were unsupported and inaccurate (6T 1156-61).

Mr. Colton further recommended expanding the LIA program for customers living below 50% of the federal poverty line to receive an extra benefit of \$25 (9T 3724). The Company agrees that not all low-income customers require the same level of assistance. Although additional assistance would be favorable, Mr. Colton does not identify a funding source, so the Company does not support his recommendation (6T 1162).

The Company similarly disagrees with Mr. Colton's recommendation to expand the LIA program to automatically enroll Food Stamp recipients (9T 3717) because the proposal does not consider the costs involved in modifying DTE Electric's billing system to somehow accommodate uploading and using data from Michigan's Food Stamp office (6T 1161, 1188-89). To the extent that DTE Electric were required to provide the additional funding for Mr. Colton's low-income proposals (or anything else), then the Company would be entitled to recover a corresponding amount through its rates, as discussed in Section IV above.

2. Low Income Renewables Pilot

In response to previously-indicated concerns about the Company providing a path for low-income customers to purchase renewable energy, the Company proposes a low-income pilot to provide increased renewable energy access for up to 2,500 qualifying low-income customers. The MIGreenPower (MIGP) program already allows customers to voluntarily go beyond the base percentage of renewable energy that they receive as part of DTE Electric's statutory requirements (15% by 2021). Enrolling in MIGP increases customers' bills, which might limit enrollment by low-income customers. The pilot would allow participants to increase their purchase of renewable

energy by 35% at no additional cost.⁸⁶ The pilot is designed to gauge interest in voluntary renewable energy by the Company's low-income customers, determine whether there are other obstacles to enrollment that exist once the price premium for incremental renewable energy is removed, and help the Company refine its activities and product offerings. Data from the pilot would support the Company's development of new pilots or programs that could be proposed in future filings.⁸⁷ The estimated total cost is \$800,000, consisting of \$250,000 for marketing, \$300,000 for IT infrastructure development, and \$250,000 for low income credits (4T 475-76; 6T 1037-39, 1060). For simplicity, the \$800,000 is included as incremental Miscellaneous Sales Expense on O&M Exhibit A-13, Schedule C5.9, column (i). Ms. Uzenski provided further accounting information (6T 1552-53).

Some parties, including ELPC and Staff expressed speculative, generalized concerns regarding matters such as customer benefits and pilot size. (See by way of example 9T 2727-2738; 9T 3193-3196) The Company's Mr. Clinton convincingly rebutted those concerns seriatim. (6T 1045, 1060-1061) Again, a pilot in DTE Electric's service territory is the only way to gather data

⁸⁶ Staff suggested that "[t]here are no direct benefits to the customer" (9T 3194). The Company disagrees, and believes that the bill credit and incremental renewable energy would directly benefit customers wishing to lower their carbon footprint (6T 1060).

ELPC witness Mr. Kenworthy indicated a concern about the pilot's size compared to the MIGP program, and asserted that the pilot "lacks additionality" (9T 2734). Mr. Clinton disagreed, explaining that with the MIGP's latest growth and the Company's expectation for continued growth, the pilot would be a meaningful addition to the MIGP program. Also, since the pilot would be a component of the MIGP program and increase participation in that program, it would satisfy the additionality suggestion. (6T 1061).

⁸⁷ Staff suggested that "the Company work with the Renewable Energy and EWR sections to revise the low income renewables pilot to provide additional benefits to low income participants and potentially file a new proposal in the next rate case" (9T 3196). The Company welcomes the opportunity to work with Staff, but would still like to offer the proposed pilot to gather data and gain insights as indicated above (6T 1061).

on how customers *actually do* act, so the Low Income Renewables Pilot should be approved and move forward to gather that data.

3. New Fixed Bill Pilot

The Company previously proposed a Fixed Bill pilot, which the Commission declined to approve based on concerns raised by Staff and intervenors, and as “not reasonable or prudent at this time” (May 2, 2019 Order in Case No. U-20162, p 144). The Company now proposes a new Fixed Bill pilot on Rate Schedule D1 (7T 2126).⁸⁸ The Company changed the previously-proposed pilot and provided additional clarifying information to address the concerns raised in Case No. U-20162 (6T 1012, 1049-60). Mr. Clinton also provided a list of major changes in response to unfounded criticisms that the presently-proposed pilot is no different than the pilot that the Company proposed in Case No. U-20162 (6T 1053-54).

In the proposed new Fixed Bill pilot, 5,000 residential customers would elect to pay a fixed monthly charge for their electricity usage for a 12-month period, and would not be subject to any adjustments resulting from usage, weather, or commodity price fluctuations. This would increase the customers’ ability to budget for and stay current on their energy bills, which could result in reduced customer service calls, fewer shut offs, reduced bad debt expense, higher enrollment in EWR programs, and increased customer satisfaction (6T 1001, 1013-16, 1022, 1056). Mr. Clinton provided additional details (6T 1027-35, 1049-60) including the removal, based on Staff’s concern, of the reasonable usage true-up adjustment that would have required customers who were removed from the program to pay for their excess usage (6T 1032).

⁸⁸ For simplicity, the pilot is limited to Rate Schedule D1, which is the Company’s largest rate class, and which includes low-income customers (6T 1107-1108).

The pilot is supported by strong customer desire that merits testing the fixed-bill concept to gather data and examine actual customer actions in order to make informed and holistic determinations. A survey of 700 residential customers indicated that 11% of respondents, or roughly 219,000 if extrapolated across the residential customer class, would actually enroll in the Fixed Bill pilot. Several other U.S. utilities are currently responding to their customers' desires by offering successful Fixed Bill programs, and their customers are highly satisfied (6T 1013-14, 1020-21, 1023, 1026-27, 1053, 1055). Other unregulated entities, such as Arcadia power, are commercializing this type of program and appear to be soliciting customers in DTE Electric's service territory. Thus, denial of a Fixed Bill pilot would inhibit DTE Electric from effectively addressing the needs of its customers. The Commission should instead support the Company's proposal, which would allow for reasonable experimentation and oversight to appropriately respond to customer preferences and improve customer satisfaction (6T 1013, 1023-26, 1049-52, 1057-58).

The Fixed Bill Pilot would also not be duplicative to the Company's BudgetWise Billing program. The Fixed Bill Pilot would provide absolute bill certainty for each 12-month term, in contrast to BudgetWise Billing, which has quarterly adjustments and an annual settlement based on actual usage. The 700-customer survey also indicated that the majority (55%) of the customers interested in the Fixed Bill option would likely come from current BudgetWise Billing customers. This shows that there is strong demand for an offering that provides greater bill certainty beyond what BudgetWise Billing affords (6T 1019-20, 1054).

In response to previously-indicated concerns about diluting price signals, Mr. Clinton explained that price signals would be clear to customers through usage alerts (warning customers of increased consumption and consequences) and estimated renewal offers. Price signals in the form of estimated renewal offers will be on the bill monthly and will provide the customer with real time

insight into their subsequent years' renewal offer based on their current usage behavior. This arguably provides a much clearer price signal and insight into the customer's future energy spend than what is currently provided on the customer's bill. Customers would be incentivized to consume less electricity during the year as they recognize that their subsequent year's renewal offer will be lower reflecting their decreased usage, much like auto insurance renewal offers incentivize safe and lawful driving. It also bears emphasis that criticisms about how customers *might* act are entirely speculative. A pilot is the only way to gather data on how customers *actually do* act (6T 1015-18, 1057-58, 1090-91).

Some parties, including Souldardarity, MEC, AG, and Staff continued to express speculative, generalized concerns regarding matters such as the Company's customer survey, other Company offerings, and energy efficiency. (See by way of example 6T 1418-1426; 9T 3119-3135; 9T 3843-3850; 9T 3059-3063) The Company's Mr. Clinton convincingly rebutted those concerns seriatim. (6T 1044-1045,1049-1060) Again, a pilot in DTE Electric's service territory is the only way to gather data on how customers *actually do* act, so the New Fixed Bill Pilot should be approved and move forward to gather that data. (6T 1015-18, 1057-58, 1090-91).

In summary, DTE Electric has studied the desirability of the pilot and structured it in a manner that the Company believes will increase customer satisfaction, and address previously-indicated concerns. It is also important to keep in mind that although some concerns may have some superficial appeal, it would be premature to draw conclusions before conducting a pilot to gather the actual data necessary to assess usage behavior, customer satisfaction, the impact on peak demand, and other factors. As such, the Company believes the new Fixed Bill pilot is reasonable and prudent and requests its approval. To facilitate the Fixed Bill pilot, DTE Electric also requests

waivers of Rules 460.125 and 460.121 of the Consumer Standards and Billing Practices for Electric and Gas Residential Service (6T 1013, 1017-19, 1027, 1035, 1049-60).

D. Secondary Rate Design Proposals

DTE Electric's secondary rate design is consistent with the methodology that the Commission approved in Case Nos. U-18014, U-18255, and U-20162. The Company proposes to continue the gradual move towards a uniform distribution rate within the class while applying a 20% cap on the increase to individual rate schedules. Exhibit A-16, Schedule F3 shows the present and proposed rate design and corresponding revenues. Exhibit A-16, Schedule F4 compares monthly bills by rate schedule based on present and proposed rates (8T 2255-59). No parties were opposed to the Company's proposal.

E. Primary Rate Design Proposals

1. Proposed Monthly Service Charges

DTE Electric's rates are designed to be cost-based in accordance with MCL 460.11, which states in part:

Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of service to each customer class.

The statute's plain language must be applied as written⁸⁹ and DTE Electric's rates are designed to accomplish this requirement (8T 2286).⁹⁰

⁸⁹ *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); and *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003) ("where the language of a statute is clear, it is not the role of the judiciary to second-guess a legislative policy choice; a court's constitutional obligation is to interpret, not rewrite, the law").

⁹⁰ In addition to the discussion here, the Company's proposed power supply rates are cost based, using the power supply base revenue deficiency/sufficiency levels by major rate class as shown on Exhibit A-16, Schedule F1.1. The Company's proposed delivery rates are cost based by voltage level, using the distribution base revenue

Mr. Bloch described the Company's major primary rate schedules,⁹¹ and explained that in accordance with Case No. U-20162, Mr. Lacey determined monthly service charges by voltage level using the Staff method, as reflected on Exhibit A-16, Schedule F1.4, line 47. Accordingly, Mr. Bloch's primary rate designs incorporate monthly service charges for primary, subtransmission, and transmission voltage level services of \$76, \$1,883, and \$3,238 respectively. All primary rates will have the same \$/kW charges, except rates D10 and R1.1 and R1.2, which have energy-based delivery charges. Mr. Bloch calculated energy charges for these rates that are equivalent to the proposed voltage level distribution charges (8T 2288).

Staff pointed out that the Company incorrectly calculated the property taxes allocated to customer classes in its calculation of customer charges in Exhibit A-16, Schedule F1.4 (9T 3249). The Company agrees that the Commission should reflect Staff's proposed changes to the calculation of property taxes for the customer charge. The Company also agrees with Staff that the currently-approved customer charges for sub-transmission and transmission customers should be retained, and that the primary customer charge should be increased to \$70 (7T 2048; 9T 3250).

deficiency/sufficiency levels by voltage class as shown on Exhibit A-16, Schedule F1.2. The proposed power supply rates include capacity and non-capacity related power supply charges in accordance with MCL 460.6w (8T 2283-84).

⁹¹ 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). 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 load (8T 2284).

2. Proposed Tariff Changes to Interruptible Service Products D3.3, D8, R1.1, R1.2, and R10, and Associated Changes to Emergency Electrical Procedures

Mr. Bloch explained that on January 30, 2019, the Company issued a System Integrity Interruption Order requiring all customers taking interruptible service under rates D3.3, D8, R1.1 and R1.2, and R10 to curtail all interruptible loads. This event was initiated by and in compliance with MISO operating procedures. As part of an after-action review, the Company determined that interruptible tariff language could be more consistent across each tariff. Mr. Bloch also proposed that to be consistent with MISO, the non-interruption penalty for non-compliance with a system integrity interruption order be calculated based on the highest 60-minute interruptible demand created during the interruption. Also, with respect to D3.3, Mr. Bloch proposed (1) a product-protection option priced at the D3 rate, (2) to eliminate the higher \$25.00 per month service charge for customers requiring interval demand metering to monitor compliance with interruption requests, and (3) to increase the contract term to one year consistent with the annual capacity registration with MISO (8T 2289). No parties were opposed to the Company's tariff proposals.

The Company also proposes changes to the Emergency Electrical Procedures in Section C3 to clarify when system integrity interruptions may occur. The proposed changes align with DTE Electric's emergency operating procedures that were developed in conjunction with the MISO emergency procedures and reviewed/approved by MISO as the Reliability Coordinator. The proposed changes also align with the Emergency Electrical Procedures that the Commission approved for Consumers Energy in Case No. U-17990 (5T 817; 8T 2289-90). No parties were opposed to the proposed changes to the Company's Emergency Electrical Procedures.

FAM witness Mr. Zakem took exception to a long standing tariff provision in Rate D8 (9T 2768), where he recommended that "the Commission delete the 'Capacity Deficiency' provision" (9T 2770). Mr. Bloch disagreed with Mr. Zakem's recommendation, explaining that he conflated

the operational requirements to interrupt load under a system integrity order with a pricing provision that does not involve load interruption. The D8 capacity deficiency provision (commonly referred to as the “buy-through provision”) is not intended for, nor used as, an operational tool since it gives the Company no rights to require a customer to interrupt load. It is simply a pricing provision that allows to a customer to choose to pay higher hourly energy rates under certain market and operating conditions, or avoid paying the higher rates by reducing or interrupting their load, at the customer’s discretion (8T 2296-97).

Mr. Zakem further suggested that the capacity deficiency provision lacks relevance because: “The concept of an LSE having to match its own resources to its own load in daily operations is obsolete, and has been obsolete since 2005” (9T 2769). To the contrary, the pricing provision continues to be relevant because when the Company is in a capacity deficiency, it is buying energy from MISO at prices above the D8 energy rate. Therefore, it makes perfect sense to use a DTE Electric capacity deficiency as a trigger for initiating a D8 buy-through event, which is ultimately priced at MISO LMP (8T 2297).⁹²

F. Streetlighting Rate Design Changes

Community Lighting provides Commission-approved tariff service to approximately 163,000 street lights on its E1 Option I Rate Schedule, approximately 200 municipally-owned street lights on its E1 Option II Rate Schedule, approximately 84,000 municipally-owned street lights on its E1 Option III Rate Schedule, and almost 30,000 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 (9T 3489).

⁹² Mr. Zakem inaccurately indicated that there is just a 0.576 cents per kWh non-interruption fee for a customer not interrupting following notice of a capacity deficiency (9T 2769). The fee also includes the cost of replacement energy plus applicable voltage level charges as described in the D8 tariff (8T 2298).

DTE Electric's proposed 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 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 (9T 3480-82). DTE Electric's proposed D9 Rate Schedule reflects recovery of costs associated with the Company's ownership, maintenance and provision of energy to its portfolio of almost 20,000 commercial and more than 9,000 residential OPLs. DTE Electric's proposed 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 (9T 3482).

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 12 months ending April 30, 2021 (9T 3494-95). Mr. Bellini explained that the lighting rates approved in Case No. U-20162 reflect a monthly energy charge, both non-capacity and capacity energy, and a luminaire charge. DTE Electric does not propose to change the methodology for allocating production and distribution revenue requirements to the various lighting rate schedules (9T 3495-96).

Mr. Bellini supported the proposed allocation of costs reflected in the various E1 Option Rate Schedule luminaire charges, testifying: "This general methodology has been consistently used by the Company and the MPSC Staff in previous general rate cases (Case Nos. U-18014, U-18255, and U-20162) as well as the Credit A case (Case No. U-20105). 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” (9T 3500). 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 (9T 3500-3502). The Company’s proposed D9 rates similarly allocate costs and continue the gradual movement toward cost-based rates (9T 3503). Mr. Bellini also explained and supported Rate Schedule E2 charges (9T 3504).

Soulardarity witness Mr. Koeppel asserted that DTE Electric is increasing rates for streetlights with above-ground wiring disproportionately as compared to streetlights with below-ground wiring, and suggested that the Company should charge similar rates regardless of whether the lines are above ground or below ground (6T 1415-17).⁹³ The Company disagrees because Mr. Koeppel’s position is contrary to legal requirements for cost-based ratemaking, and the record concerning applicable costs, as indicated above. Staff similarly found that Mr. Koeppel’s assessment of street lighting rates was incorrect, and his recommendations should be denied (9T 3142-44).

G. Nuclear Surcharge

The nuclear surcharge recovers costs for Fermi 2 site security, radiation protection, nuclear decommissioning,⁹⁴ 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 (SSRP) portion of the surcharge. The Nuclear Decommissioning funding and LLRW disposal funding are

⁹³ These assertions in Mr. Koeppel’s revised direct testimony, filed on November 26, 2019, were somewhat different than the assertions in his original testimony.

⁹⁴ The Commission previously approved DTE Electric’s proposed nuclear surcharge but directed the Company to provide an updated decommissioning study (May 2, 2019 Order in Case No. U-20162, p 121). This is a complex project that the Company has started and forecasts to complete in May of 2020 (9T 3459-60, 3465, Exhibit A-13, Schedule C5.16, page 1, line 23). See section VIII. C. 4 (regarding Fermi 2 O&M Expenses) for a further discussion of the decommissioning study.

unchanged. The resulting nuclear surcharge is \$38.7 million for the projected test period (Exhibit A-20, Schedule J1, page 1, line 5, column (b)), which is an increase of \$0.4 million from the currently-authorized nuclear surcharge (9T 3461. See also 6T 2288 and Exhibit A-16, Schedule F6). The Company's proposed nuclear surcharge is reasonable and prudent, and therefore should be approved (9T 3461-62).

H. Distributed Generation (DG) Tariff (Rider 18)

The Commission previously adopted the Staff's method to calculate the outflow credit for customers taking Distributed Generation (DG) service under Rider 18 (May 2, 2019 Order in Case No. U-20162, p 180). The outflow credit is based on power supply costs less transmission costs, and is calculated on Exhibit A-16, Schedule F7. The outflow credits in this case are calculated using the same methodology approved by the Commission in Case No. U-20162. 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 (7T 2126-27).

GLREA witness Mr. Rafson proposed several changes to Rider 18 (9T 2788). Mr. Dennis responded by observing that GLREA appears to recommend returning to true net metering, and that the Commission firmly rejected that position (7T 2133-34, quoting the May 2, 2019 Order in Case No. U-20162). Mr. Rafson also apparently ignored or misunderstood Case No. U-20162 in asserting that "DTE has not established or recognized the capacity value created by DG..." (9T 2785). The Commission "adopt[ed] the Staff's proposal to calculate the outflow credit based on power supply less transmission" (May 2, 2019 Order in Case No. U-20162, p 180). Accordingly, the current methodology is to credit DG customers for outflow, which includes both the capacity and non-capacity rates of power supply (7T 2134). Staff similarly disagreed with GLREA's DG

characterizations and proposals, and recommended rejection of GLREA's suggested DG tariff changes (9T 3386-88).

GLREA witness Mr. Richter similarly ignored Case No. U-20162 in claiming that a 2018 Staff Report "found that under true net metering . . . DG customers were already subsidizing non-DG customers," and that DG customers should be credited "for their outflow at a rate of approximately the full retail rate, or a little higher" (9T 2795). In addition to the discussion above, Mr. Dennis disagreed for three more reasons. First, the table referenced on page 23 of Staff's report was ultimately dismissed by Staff, and Staff did not recommend splitting DG customers into a separate class. Second, Staff's report repeatedly referred to true net metering as being a subsidized rate. Third, Staff's report, like Staff's testimony in Case No. U-20162, recommended an Inflow/Outflow mechanism (7T 2134-35). Staff similarly disagreed with Mr. Richter (9T 3388-90).

Staff suggested that the Company should voluntarily accept applications into the DG program beyond the statutory 1% cap (9T 3265-68). The Company disagrees because the 1% limit set on the DG program (Rider 18) and net-metering program (Rider 16) was established by statute, and that statute remains in effect (4T 495).⁹⁵

The Company also disagrees with Staff's suggestion that the cap is unnecessary because Rider 18 is cost-based. Ms. Crozier explained that several inequities remain that prevent the Company from voluntarily lifting the cap. First, the lack of a system access charge (SAC) as proposed by the Company in Case No. U-20162 for Rider 18 customers shifts costs and imposes a

⁹⁵ 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."

burden on non-DG customers. Second, a DG customer who has Rate Schedule D1.2 in conjunction with Rider 18 does not have cost-based rates.⁹⁶ Third, Rider 18 contains an outflow credit to DG customers at the full retail power supply rate, less transmission, which compensates the customer for a capacity component. As the Company explained in Case No. U-20162, however, none of the Company's capacity requirements are offset by DG and net metering customers. Therefore, lifting the 1% cap could expose the Company to uncapped revenue shifts, and expose non-DG customers to increased and improper cost subsidizations (4T 495-96).

Mr. Jester proposed that SolarCurrents customers be allowed to remain on Rider 16 for the twenty-year term of the SolarCurrents contract (9T 3853-55). The Company disagrees because Michigan law provides for the termination of net metering.⁹⁷ The Company will, however, continue to purchase SolarCurrents customers' renewable energy credits (RECs) at the agreed-upon prices for the full twenty-year term of the SolarCurrents contract (7T 2136).

I. Shadow Billing

The Commission previously found "planning for the implementation of shadow billing appropriate for DTE Electric to include in its next rate case, particularly at this juncture given the forthcoming D1 rate switch to on-peak summer and all-other hours rates" (May 2, 2019 Order in Case No. U-20162, p 166). Mr. Campbell explained that the Company plans to use a Bill Simulator

⁹⁶ Mr. Dennis further explained that not all of the Company's on- and off-peak rates accurately represent the cost-based value of outflow delivered to the utility and used Rate Schedule D1.2 as an example. Rate Schedule D1.2 is a time-of-use rate that was designed to incent customers to shift usage from the on-peak period to the off-peak period. The D1.2 rate was *not* designed to accurately reflect the actual cost difference between using power in the two periods, nor was it designed to accurately reflect what DG customers should be compensated for outflow (7T 2132-33).

⁹⁷ MCL 460.1183 states:

(1) A customer participating in a net metering program approved by the commission before the commission establishes a tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of enrollment.

to implement shadow billing.⁹⁸ On June 3, 2019, the Company issued a Request for Proposal (RFP) for services consisting of the implementation, integration, and deployment of the Bill Simulator for the web and mobile phone users, High Bill alerts, Customer Service Tools and related software. There will be a two-phased (Pilot and Full Rollout) approach to deliver value as quickly as possible. The Company plans (1) final vendor selection no later than the fourth quarter of 2019, (2) including up to 20,000 customers in the pilot, which is tentatively scheduled to begin by the second quarter of 2020, and (3) full rollout to begin May 2022. A cost estimate will be determined when the proposals are reviewed (8T 2565-66).

J. Rate Implementation Date

Staff suggested that new rates become effective seven calendar days from the date of the Order in this case (9T 3127). The Company can comply with this suggestion, which would give the Company time to populate the billing system (4T 493). The Company disagrees, however, with Staff's alternative proposal that rates not become effective until after as much as thirty days after the Order is issued, in order to correct potential errors (9T 3127-28). The Company is not opposed to having a means for error correction, but errors can simply be corrected as soon as possible if any are found. Staff's alternative proposal should be rejected because it would effectively transform a rate case (which is statutorily required to be completed in 10 months) into an eleven month case, and could cause the Company to suffer financial harm by not receiving rate relief at the start of the projected test year (4T 493-94).

⁹⁸ The Company defines shadow billing as the process of providing customers the appropriate tools to understand and navigate the options of alternative rates to assist them in selecting the rate option that best fits the customer's needs (Camp 21).

XII. REQUEST FOR RELIEF

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

A. Granting DTE Electric's request for final rate relief, as further supported and explained in its Application, testimony, exhibits, and this Initial Brief (including Attachments A and B) approving rates that will recover **the Company's revenue deficiency of approximately \$343.0 million**, based on a May 1, 2020 through April 30, 2021 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 May 8, 2020 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. Approving recovery of DTE Electric's generation investments;

F. Approving recovery of DTE Electric's investments related to the strengthening of the Company's distribution system and reliability improvements;

G. Approving a capacity charge based on the methodology established in Case No. U-20162 and the capacity-related costs approved in this proceeding;

H. Granting DTE Electric's request for increased tree trimming expenditures, and the associated request for regulatory asset treatment through 2022;

I. Approving the Company's proposed Fixed Bill pilot program, and granting a waiver of the Commission's Residential Billing Rules R 460.125 and 460.121;

- J. Approving the Company's proposed low-income renewable energy pilot;
- K. Granting DTE Electric's request to approve the PSCR base;
- L. Approving DTE Electric's proposals to implement certain customer rate schedules and tariffs;
- M. Approving the Company proposal to make the Residential Income Assistance (RIA) Provision, which is currently available only to rate schedule D1 customers, available to other non-supplemental residential rate schedules.
- N. Approving the Company proposal to increase the funding for the Low-Income Assistance program (LIA) from \$15.4 million to \$24 million, to accommodate a projected increase of customers enrolled in the Low-Income Self-Sufficiency program (LSP).
- O. Approving the proposed accounting requests related to PERC deferral mechanism, the deferral of all net OPEB expense, the deferral of actual net pension expense in excess or less than \$50.7 million and the impacts of adopting ASU 2018-15, Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement.
- P. 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

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

Respectfully submitted,

DTE ELECTRIC COMPANY

Legal Department

Dated: January 14, 2020

By: _____
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DTE Electric Company
Computation of Revenue Deficiency
for the 12 Month Period Ending April 30, 2021
(\$000)

MPSC Case No. U-20561
Initial Brief
Attachment A
Page 1 of 4

Line No.	(a) Description	(b) Source	(b) U-20561 Filed	(c) Adjustments	(d) U-20561 Initial Brief Position
1	Rate Base	Attach A, Page 2	\$ 18,251,329	\$ (83,780)	\$ 18,167,548
2					
3	Adjusted Net Operating Income	Attach A, Page 3	788,214	890	789,104
4					
5	Rate of Return	Attach A, Page 4	5.73%	0.004%	5.73%
6					
7	Income Requirements		1,046,495	(4,804)	1,041,691
8					
9	Income Deficiency (Sufficiency)		258,281	(5,693)	252,587
10					
11	Revenue Conversion Factor	Exh. A-13, Sch C2	1.3496		1.3496
12					
13	Revenue Deficiency (Sufficiency)		\$ 348,584	\$ (7,684)	\$ 340,901
14					
15	Tree Trim Surge	Exh. A-11 Sch A1	2,104		2,104
16					
17	Total Revenue Deficiency (Sufficiency)		\$ 350,688	\$ (7,684)	\$ 343,005

DTE Electric Company
Rate Base - Average Net Plant
for the 12 Month Period Ending April 30, 2021
(\$000)

MPSC Case No. U-20561
Initial Brief
Attachment A
Page 2 of 4

Line No.	(a) Description	(b) U-20561 Filed	(c) Adjustments	(d) U-20561 Initial Brief Position
1	Plant in Service	\$ 22,446,199	\$ (14,141) (1)	\$ 22,432,058
2	Plant Held for Future Use	75,808		75,808
3	Construction Work in Progress	1,851,001		1,851,001
4	Aquisition Adjustment	0		0
5	Total Utility Plant	24,373,008	(14,141)	24,358,867
6				
7	Less: Depreciation Reserve	(7,733,089)	382 (2)	(7,732,707)
8				
9	Net Utility Plant	16,639,919	(13,759)	16,626,160
10				
11	Net Capital Lease Property	3,785		3,785
12	Net Nuclear Fuel Property	149,310		149,310
13				
14	Total Utility Property and Plant	16,793,014	(13,759)	16,779,255
15				
16	Less: Capital Lease Obligations	3,798		3,798
17				
18	Net Plant	16,789,215	(13,759)	16,775,456
19				
20	Allowance for Working Capital	1,462,113	(70,021) (3)	1,392,092
21				
22				
23	Rate Base	\$ 18,251,329	\$ (83,780)	\$ 18,167,548

(1) average impact of capital reductions

- Contingency - Power Generation	(11,700)	9T 3211
- Contingency - HQ Energy Center	(2,441)	9T 3211
	<u>(14,141)</u>	

(2) Depreciation Reserve Impact

- Contingency - Power Generation	224	9T 3211
- Contingency HQ Energy Center	158	9T 3211
	<u>382</u>	

(3) Working Capital

- Corrected Error for Accts Pay - Assoc Comp	(2,000)	9T 3217
- Corrected Error for Accts Rec - Assoc Comp - REF	(68,021)	9T 3240
	<u>(70,021)</u>	

DTE Electric Company
Adjusted Net Operating Income
for the 12 Month Period Ending April 30, 2021
(\$000)

MPSC Case No. U-20561
Initial Brief
Attachment A
Page 3 of 4

Line No.	(a) Description	(b) U-20561 Filed	(c) Adjustments	(d) U-20561 Initial Brief Position
	<u>Net Operating Income</u>			
	<u>Operating Revenues</u>			
1	Sales Revenues	\$ 4,867,365		\$ 4,867,365
2	Other Operating Revenue	-		0
3	Fuel and Purchased Power	1,384,989		1,384,989
4	Net Margin	<u>3,482,376</u>	<u>0</u>	<u>3,482,376</u>
5				
6	<u>Operating Expenses</u>			
7	Operations and Maintenance Expenses	1,353,445	(1,285) (1)	1,352,160
8	Depreciation and Amortization	949,590	(412) (2)	949,178
9	Property and Other Taxes	331,766		331,766
10	Total Operating Expenses	<u>2,634,801</u>	<u>(1,697)</u>	<u>2,633,104</u>
11				
12	Operating Income	847,575	1,697	849,272
13				
14	<u>Other Operating Income Adjustments</u>			
15	Allow. For Funds Used During Constr	31,892		31,892
16	Amortization of Loss on Reacquired Debt	(3,214)		(3,214)
17	Other Income/Deductions	(994)		(994)
18	Total Operating Income Adjustments	<u>27,683</u>	<u>0</u>	<u>27,683</u>
19				
20	PreTax Net Operating Income	<u>\$ 875,258</u>	<u>\$ 1,697</u>	<u>\$ 876,955</u>
21				
22	State & Local Income Taxes	43,559	105	43,665
23	Federal Income Taxes	43,484	702	44,187
24	Income Tax Effect of Interest	-		-
25	Interest Synchronization Tax adjustment	-		-
26		<u>87,044</u>	<u>808</u>	<u>87,851</u>
27	Net Operating Income	<u>\$ 788,214</u>	<u>\$ 889</u>	<u>\$ 789,104</u>

(1) O&M

- EV Amortization - Electric Marketing expense	(3)	(1,000)	6T 1574-1575
- Corporate Membership due - A&G expense		(281)	6T 1616
- DTE Gas corporate membership		(4)	6T 1609
		<u>(1,285)</u>	

(2) Depreciation and Amortization

- depr related to contingency		(412)	9T 3211
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(3) amortization of audited expense \$44,000 less filed amortization of \$628,000 less U-17767 PEV amort of \$415,000

**DTE Electric Company
 Computation of Revenue Deficiency
 Rate of Return Summary for April 30, 2021
 Based on Average Rate Base**

Line No.	Description	Amount (\$000)	Percent	Cost %	Weighted Cost % (1)	Weighted Cost %		
U-20561 Filed (Test Period Average Basis)								
1	Long-Term Debt	\$ 6,995,149	50.01%	38.33%	4.310%	2.16%	1.65%	100.00%
2	Preferred Stock	0	0.00%	0.00%	0.000%	0.00%	0.00%	134.96%
3	Common Shareholders' Equity	6,993,099	49.99%	38.32%	10.500%	5.25%	4.02%	134.96%
4	Total	13,988,248	100.00%			7.40%		5.43%
5								
6	Short-Term Debt	219,881		1.20%	3.249%		0.04%	100.00%
7								
8	Job Development - ITC - Debt	24,309		0.13%	4.310%		0.01%	100.00%
9	Job Development - ITC Equity	24,309		0.13%	10.500%		0.01%	134.96%
10	Total Job Development - ITC	48,618						0.02%
11								
12	Deferred Income Taxes (Net)	3,994,582		21.89%	0.000%		0.00%	0.00%
13								
14	Total	18,251,329		100.00%			5.73%	7.15%
15								
U-20561 Initial Brief (Test Period Average Basis)								
16	Long-Term Debt	\$ 6,995,149	50.01%	38.33%	4.310%	2.155%	1.65%	100.00%
17	Preferred Stock	0	0.00%	0.00%	0.000%	0.000%	0.00%	134.96%
18	Common Shareholders' Equity	6,993,099	49.99%	38.32%	10.500%	5.249%	4.02%	134.96%
19	Total	13,988,248	100.00%			7.404%		5.43%
20								
21	Short-Term Debt	219,881		1.20%	3.249%		0.04%	100.00%
22								
23	Job Development - ITC - Debt	24,309		0.13%	4.310%		0.01%	100.00%
24	Job Development - ITC Equity	24,309		0.13%	10.500%		0.01%	134.96%
25	Total Job Development - ITC	48,618						0.02%
26								
27	Deferred Income Taxes (Net)	3,994,582		21.89%	0.000%		0.00%	0.00%
28								
29	Total	18,251,329		100.00%			5.73%	7.15%

DTE Electric Company
Revenue Requirement Adjustments to Company's Filing
for the 12 Month Period Ending April 30, 2021
(\$000)

Line No.	(a) Description	(b) Source	(c) Revenue Deficiency (Pre Tax Amts)
1	Company's Filed Position	Exhibit A-11 Sch A1	\$ 350,688
2			
3	<u>Adjustments to Revenue Deficiency:</u>		
4			
5	Rate Base (1)		<u>Changes</u>
6	- Net Plant: Contingency - Power Generation	Attach A, p2	(11,476) (820)
7	- Net Plant: Contingency - HQ Energy Center	Attach A, p2	(2,283) (163)
8			
9	- Working Capital: Corrected Error for Accts Pay - Assoc Comp	Attach A, p2	(2,000) (143)
10	- Working Capital: Corrected Error for Accts Rec - Assoc Comp - REF	Attach A, p2	<u>(68,021) (4,860)</u>
11			(83,780)
12			
13	Depreciation		
14	- Capital Contingency	Attach A, p3	(412)
15			
16	O&M Expenses		
17	- Electric Vehicle Amortization		
18	- Corporate Memberships	Attach A, p3	<u>(1,285)</u>
19			
20	Total Adjustments to Company's Initial Revenue Deficiency	Line 6 through Line 17	<u>\$ (7,683)</u>
21			
22	Company's Brief Position	Line 1 + Line 16	<u>\$ 343,005</u>

(1) Rate Base Change multiplied by pre-tax return 7.15% (Exh. A-11, Sch D1)

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-20561

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON, being duly sworn, deposes and says that on the 14th day of
January, 2020, she served a copy of DTE Electric Company's Initial Brief, via electronic mail
upon the persons referred to in the attached service list.

ESTELLA R. BRANSON

Subscribed and sworn to before
me this 14th day of January, 2020

Lorri A. Hanner, Notary Public
Wayne County, Michigan
My Commission Expires: 4-20-2020
Acting in Wayne County, MI

MPSC Case No. U-20561

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MPSC Case No. U-20561

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