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-20162

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on March 6, 2019.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before March 25, 2019, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before April 5, 2019 at noon.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Sally L. Wallace

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Sally L. Wallace
Administrative Law Judge

March 5, 2019
Lansing, Michigan

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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PROPOSAL FOR DECISION

I.

HISTORY OF PROCEEDINGS

On July 6, 2018, DTE Electric Company (DTE Electric) filed an application requesting authority to increase its retail rates for the generation and distribution of electricity by approximately $328 million.[1] DTE Electric requested other forms of regulatory relief including miscellaneous accounting authority. At the time of filing, DTE Electric was providing service pursuant to rates that had been established by the Commission's April 18 and June 28, 2018 orders in Case No. U-18255.

[1] On July 24, 2018, in Case No. U-20105, the Commission issued an order (July 24 order) approving a settlement agreement that adjusted DTE Electric's rates consistent with the 2017 Tax Cuts and Jobs Act (TCJA) that reduced the company's federal tax rate. As several parties pointed out, the expiration of the rates approved in the July 24 order (which would then revert to the higher rates approved in Case No. U-18255), concurrently with the establishment of new rates in the Commission's order in this case, effectively makes DTE Electric's rate increase request approximately $485 million, rather than the $328 million stated in the company's application.

Based on a May 1, 2019 through April 30, 2020 projected test year, the company stated that the rate increase was necessary to recover capital costs associated with additions to its generation and distribution system, because of capital structure cost changes, increased operation and maintenance (O&M) expense, and inflation and accounting standard changes. DTE Electric requested a return on equity (ROE) of 10.50% with an overall rate of return of 5.76% after tax, 7.19% pre-tax. The company requested a permanent capital structure of 51% equity and 49% long-term debt. DTE Electric's projected average rate base for the test year is approximately $17.2 billion.

In addition to rate relief, DTE Electric requested approval for several changes to its Residential Rate D1 rate design to a time-of-use (TOU) based charge; Weekend Flex and Fixed Bill pilot programs (along with associated waivers of Commission rules); a new distributed generation (DG) tariff (Rider 18); voltage level adjustments for demand charges; changes to power supply cost allocation for standby service (along with changes to rate design); and an infrastructure recovery mechanism (IRM) with associated surcharges for 2020-2022. DTE Electric also proposed an electric vehicle (EV) rebate program (Charging Forward), requesting accounting authority to defer rebates as a regulatory asset.

DTE Electric proposed to significantly increase its tree-trimming expenditures to arrive at a five-year tree-trimming cycle (Enhanced Tree Trimming Program (ETTP) surge). The company proposed to defer a portion of the associated expense as a regulatory asset to be securitized when an appropriate asset balance is reached.

Finally, DTE Electric requested Commission authority for regulatory asset treatment of: (1) 2017 Customer 360 post-implementation O&M expense; (2) certain advanced distribution management system (ADMS) costs; (3) TOU rate implementation expenses; and (4) over- or underrecovery of IRM expenses.

A prehearing conference was held on July 25, 2018, attended by the company, the Commission Staff (Staff), and a number of parties petitioning to intervene. Intervenor status was granted to the Michigan Cable Telecommunications Association; Kroger Co. (Kroger); Department of the Attorney General (Attorney General); the Association of Businesses Advocating Tariff Equity (ABATE); Michigan Environmental Council (MEC); Natural Resources Defense Council (NRDC); Energy Michigan; Sierra Club (SC) (collectively, MEC/NRDC/SC); Great Lakes Renewable Energy Association (GLREA); ChargePoint, Inc.; Residential Customer Group (RCG); Environmental Law and Policy Center, Ecology Center (EC), Solar Energy Industries Association, and Vote Solar (collectively, ELPC); Michigan Energy Innovation Business Council and Institute for Energy Innovation (together, EIBC/IEI); Local 223, Utility Workers Union of America, AFL-CIO; and Wal-Mart, Inc. Finally, a schedule for the proceeding was established in accordance with the 10-month rate case deadline required by 2016 PA 341 (Act 341). On August 1, 2018 a protective order was entered, and on August 21, 2018, Soulardarity's petition to intervene out of time of was granted.

On October 19, 2018, MEC filed a motion to strike certain testimony and an exhibit of DTE Electric witness Robert D. Feldmann. On October 29, 2018, DTE Electric filed an answer opposing the motion, and on November 1, 2018, a hearing on the motion was conducted. The motion was denied in a ruling issued on November 7, 2018.

Also, on November 7, 2018, the Staff and several intervenors filed testimony and exhibits. On November 27, 2018, ABATE filed a motion to compel, which was later withdrawn, and on November 28, 2018, DTE Electric, the Staff, MEC/NRDC/SC and EIBC/IEI, ABATE, Kroger, ChargePoint, and ELPC filed rebuttal testimony and exhibits. On December 4, 2018, MEC/NRDC/SC and the Staff filed motions to strike certain portions of the testimony and a part of an exhibit of DTE Electric witness Matthew T. Paul. On December 10, 2018, DTE Electric filed responses in opposition to the motions. Both motions to strike were granted.[2]

Evidentiary hearings were held from December 12 through December 19, 2018. 25 witnesses appeared for cross-examination, while the testimony and exhibits of the remaining witnesses were bound into the record. On December 28, 2018, GLREA and others filed a letter addressed to the Commission requesting that the Commission convene at least two public hearings in DTE Electric's service area to address issues concerning the company's proposed DG tariff. On January 15, 2019, the Commission denied the request for additional public hearings.

Briefs and reply briefs were filed on January 11 and January 31, 2019, respectively. The evidentiary record is contained in 4,307 pages of transcript in 8 volumes and over 400 exhibits admitted into evidence, with portions of testimony, cross-examination, and certain exhibits filed confidentially subject to the protective order.

This PFD follows the standard rate case outline, with an overview of the testimony and pre-filed exhibits in section II, test year in section III, rate base issues addressed in section IV, cost of capital in section V, adjusted net operating income in section VI, revenue deficiency/excess in section VII, other revenue-related issues are covered in

[2] See, 4 Tr 488-492; 502-503.

section VIII, cost of service is discussed in section IX, rate design and tariff issues are addressed in section X and miscellaneous issues are addressed in section XI.

In order to ensure compliance with the statutorily imposed timeframe for deciding this case, only the evidence and arguments necessary for a reasoned analysis of the disputed issues are expressly addressed in this PFD.[3] However, all of the evidence presented in this case, and the arguments made by the parties based on that evidence, was considered.

II.

OVERVIEW OF THE RECORD

This section provides a general overview of the direct testimony, rebuttal testimony, and pre-filed exhibits of the various witnesses. The record is discussed in much more detail in the sections that follow.

A. DTE Electric

Don M. Stanczak, Vice-President, Regulatory Affairs for DTE Energy Corporate Services, LLC, provided a general overview of the rate case, a review of the method used to compute projected test year amounts, testimony concerning DTE Electric's proposed changes to its capacity charge, and recommendations concerning the company's pending depreciation case. Mr. Stanczak also provided an overview of the company's proposed IRM, proposed accounting treatment for enhanced tree-trimming, and the status of the implementation of residential TOU rates. Mr. Stanczak's revised direct testimony and

[3] Certain noncontroversial issues are included for completeness. For issues where the ALJ found that a particular argument or prior determination was dispositive, this PFD provides only a limited summary of the record.

rebuttal testimony are transcribed at 3 Tr 61 through 106. Cross-examination and redirect of Mr. Stanczak begins at 3 Tr 108 and ends at 3 Tr 189.

Derek M. Arnold, Supervisor of the Strategic Merchant Analytics Team in DTE Electric's Generation Optimization Department, testified regarding capacity-related generation costs, the benefit of energy and ancillary service sales from DTE Electric's capacity resources, and the sales revenue, net of fuel costs, included in the company's power supply cost recovery (PSCR) factor. Mr. Arnold sponsored Exhibit A-29, Schedules S-1 through S-3, and his direct and rebuttal testimony are transcribed at 3 Tr 284 through 302. Cross-examination of Mr. Arnold can be found at 3 Tr 303 through 3 Tr 335.

Timothy A. Bloch, Principal Financial Analyst in Regulatory Affairs for DTE Energy Corporate Services, LLC, testified in support of DTE Electric's proposed changes to the determination of voltage level energy discounts and voltage level demand adjustments, including a proposal to add voltage level demand adjustments to rate D6.2 demand charge; proposed changes to power supply cost allocation and rate design to Standby Service Rider 3; changes to Retail Access Service (Choice) Rider EC-2 for electric choice customers returning to bundled service; the calculation of the nuclear surcharge; and the proposed IRM surcharges and reconciliation calculation. Mr. Bloch sponsored Exhibit A-16, Schedules F2 through F6 and Schedules F10 and F12, and Exhibit A-30, Schedule T10. Mr. Bloch's revised direct testimony and rebuttal testimony are transcribed at 5 Tr 1213 through 1263.

Marco A. Bruzzano, an employee of DTE Energy Corporate Services, LLC, working in electrical engineering and planning, scheduling, and coordination, testified concerning DTE Electric's historical and projected capital and O&M expenses related to electric distribution. In addition, Mr. Bruzzano testified in support of the IRM. Mr. Bruzzano sponsored Exhibits A-12, Schedule B5.4; Exhibit A-13, Schedule C5.6; Exhibit A-23, Schedules M-1 through M-5; Exhibit A-30, Schedules T2 and T2.1; Exhibit A-31, Schedules U1 through U-11. Mr. Bruzzano's revised direct testimony and revised rebuttal testimony can be found at 4 Tr 691 through 900. Cross-examination of Mr. Bruzzano can be found at 4 Tr 901 through 5 Tr 1027.

Eric W. Clinton, Manager in DTE Electric's Regulated Marketing Organization, testified regarding the company's proposed electric vehicle (EV) program as well as the proposed Weekend Flex and Fixed Bill pilot programs. Mr. Clinton also provided details about DTE Electric's regulated marketing O&M expense and restructuring rate D1 to TOU. Mr. Clinton sponsored Exhibit A-13, Schedule C5.8. His revised direct testimony and rebuttal testimony can be found at 6 Tr 2075 through 6 Tr 2129. Cross-examination of Mr. Clinton can be found at 6 Tr 2130 through 6 Tr 2141.

Michael S. Cooper, Director of Compensation, Benefits & Wellness for DTE Energy Corporate Services, LLC, provided an overview of the company's compensation practices and supported DTE Electric's pension and other post-employment benefits (OPEB) costs, labor and composite inflation factors, and incentive compensation plans. Mr. Cooper sponsored Exhibit A-13, Schedules C5.10 through C5.10.2 and C5.11.1 and C11.2; and Exhibit A-21, Schedules K1 through K5. Mr. Cooper's revised direct testimony and revised rebuttal testimony are transcribed at 6 Tr 1807 through 6 Tr 1886. Cross-examination of Mr. Cooper can be found at 6 Tr 1887 through 6 Tr 1907.

Jeffrey C. Davis, Manager of Nuclear Strategy and Business Support for DTE

Electric, testified regarding the company's historical and projected nuclear capital and O&M expenses. Mr. Davis also supported the projected nuclear surcharge and the nuclear generation part of the IRM. Mr. Davis sponsored Exhibit A-12, Schedule B5.3; Exhibit A-13 Schedules C5.3 and C5.16; Exhibit A-20, Schedule J1; and Exhibit A-30, Schedule T4. Mr. Davis's direct testimony and rebuttal testimony are transcribed at 5 Tr 1265 through 1329.

Philip W. Dennis, Manager, Regulatory Economics for DTE Energy Corporate Services, LLC, testified regarding rate design and tariff language modifications for residential rate D1. Mr. Dennis also provided support for an increased service charge for rates D1, D1.2, D1.6, D1.8, D2 and supported the Weekend Flex and Fixed Bill pilot programs. Mr. Dennis sponsored Exhibit A-16, Schedules F3 through F10 (revised), F10.1; and Exhibit A-42, Schedule FF1-FF3. Mr. Dennis's revised direct testimony and rebuttal testimony are transcribed at 8 Tr 3855 through 3906. Cross-examination of Mr. Dennis can be found at 8 Tr 3907 through 8 Tr 3910.

Irene M. Dimitry, Vice President of Business Planning & Development for DTE Energy Corporate Services, LLC, explained DTE Electric's demand-side management (DSM) programs and efforts and supported the company's capital expenditures for these programs. Ms. Dimitry also discussed the company's economic analysis regarding the continued operation of River Rouge Unit 3 until its retirement in 2020. Ms. Dimitry sponsored Exhibit A-12, Schedules B5.6 and B6. Her direct testimony and rebuttal testimony are transcribed at 3 Tr 339 through 389. Cross-examination of Ms. Dimitry begins at 3 Tr 390 and continues through 4 Tr 482. Portions of Ms. Dimitry's cross examination are contained in a confidential record.

Keegan O. Farrell, Principal Financial Analyst-Load Forecast for DTE Energy Services, LLC, testified regarding projected allocation schedules for the test year, the company's method for forecasting choice load, the hours used for summer on-peak, non-capacity charge for rate D1, and the anticipated load shift under the Weekend Flex pilot program. Mr. Farrell sponsored Exhibit A-5, Schedules E2 and E3, and Exhibit A-17, Schedules G1.1 and G1.2. His testimony is transcribed at 5 Tr 1331 through 1345.

Robert D. Feldmann, Executive Director Electric Sales and Marketing for DTE Electric, testified regarding the company's investment in a combined heat and power (CHP) facility at Ford Motor Company's Research and Engineering campus (Ford R&E). Mr. Feldmann's testimony was in support of the inclusion of the facility in rate base. Mr. Feldmann sponsored Exhibit A-28, Schedules R1 and R2. His revised direct testimony and rebuttal testimony can be found at 5 Tr 1124 through 1142. Cross-examination of Mr. Feldmann begins at 5 Tr 1144 and continues through 5 Tr 1206.

Daniel J. Griffin, Director-Information Officer in the Information Technology (IT) Services organization in DTE Energy Corporate Services, LLC, testified regarding IT planning and benefits. In addition, Mr. Griffin supported historical and projected IT capital spending and the impact of changing rate D1 to a TOU rate. Mr. Griffin sponsored Exhibit A-12, Schedules B5.7 and B5.7.1 through B5.7.5. His direct and rebuttal testimony are transcribed at 5 Tr 1348 through 1417.

Kelly A. Holmes, Principal Financial Analyst-Regulatory Economics in Regulatory Affairs for DTE Energy Corporate Services, LLC, testified regarding the company's proposed rate design for commercial secondary tariffs D3, D3.2, D3.3, D4, and D8. Ms. Holmes also testified about power supply rates designed to include a capacity charge in accordance with 2016 PA 341 (Act 341), and projected power supply costs. Ms. Holmes sponsored Exhibit A-13, Schedules C4 and C5.14 and Exhibit A-16, Schedules F3, F4, and F10. Ms. Holmes's revised direct testimony is transcribed at 5 Tr 1419 through 1433.

Tamara D. Johnson, Director, Revenue Management and Protection for DTE Energy LLC, testified regarding the company's historical and projected O&M expense for customer service. Ms. Johnson's testimony included historical and projected uncollectibles expenses, support for merchant fees, customer service performance, DTE Electric's Low Income initiative, Customer 360 costs, and the effect of restructuring rate D1 to TOU. Ms. Johnson sponsored Exhibit A-13, Schedules C5.7 and C5.12. Her direct testimony and rebuttal testimony are transcribed at 7 Tr 3106 through 3144. Cross-examination of Ms. Johnson begins at 7 Tr 3145 and continues through 7 Tr 3197.

Ting Zhou, Manager of Community Lighting for DTE Electric, supported the forecast for various outdoor lighting rates including traffic signals. Ms. Zhou also testified concerning rate design for outdoor lighting and historical and projected capital and O&M expense. Ms. Zhou sponsored Exhibit A-12, Schedule B5.5; A-13, Schedule C5.6; Exhibit A-16, Schedules F3 and F10 (revised); and Exhibit A-25, Schedules O1 and O2. Ms. Zhou's revised testimony is transcribed at 5 Tr 1435 through 1470.

Thomas W. Lacey, Principal Financial Analyst in the Revenue Requirements Department of DTE Energy Corporate Services LLC's Regulatory Affairs Organization testified regarding unbundled cost of service studies (COSS) for the projected test year. Mr. Lacey also provided support for revenue requirement calculations for customer costs, capacity charge, and IRM by rate class. Mr. Lacey sponsored Exhibit A-16, Schedules F1.1 through F1.5 and Exhibit A-30, Schedules T8 and T9. Mr. Lacey's revised direct testimony and rebuttal testimony are transcribed at 7 Tr 3201 through 3234. Cross-examination of Mr. Lacey begins at 7 Tr 3235 and continues through 7 Tr 3267.

Markus B. Leuker, Manager of Corporate Energy Forecasting for DTE Electric, provided the company's current electric sales, system demand, and system output for 2018-2028. Mr. Leuker sponsored Exhibit A-5, Schedule E1 and Exhibit A-15, Schedules E1-E5. Mr. Leuker's testimony is transcribed at 5 Tr 1472 through 1496.

David C. Milo, Fuel Resources Specialist in the Operations and Logistics group of DTE Electric's Fuel Supply Department, testified regarding DTE Electric's historical and projected fuel supply and Midwest Energy Resources Company's (MERC) fuel handling capital and O&M expenses. Mr. Milo sponsored Exhibit A-12, Schedule B5.2 and Exhibit A-13, Schedule C5.2. Mr. Milo's direct testimony and revised rebuttal testimony are transcribed at 6 Tr 2283 through 2295. Cross-examination of Mr. Milo begins at 6 Tr 2296 and continues through 6 Tr 2314.

Jaqueline L. Robinson, Director of Operational Technology in Electric Distribution Operations for DTE Electric, testified regarding the reasonableness and current status of DTE Electric's AMI program. Ms. Robinson also supported AMI communications upgrade from 3G to 4G, AMI industrial upgrade to 4G, AMI leveraged tools, and the status of the AMI opt-out program. Ms. Robinson sponsored Exhibit A-12, Schedule B5.4; Exhibit A-19, Schedule I1; and Exhibit A-23, Schedule M4. Ms. Robinson's revised direct testimony and rebuttal testimony are transcribed at 8 Tr 3942 through 3968. Cross-examination of Ms. Robinson begins at 8 Tr 3969 and continues through 8 Tr 3975.

Matthew T. Paul, Vice President Fossil Generation Plant Operations for DTE Electric, testified regarding historical and projected capital and O&M expenditures for steam and hydraulic power generation and peaking units, including Tier 1 and Tier 2 coal units. Mr. Paul also provided detail on forecasted plant capacity ratings, and total system capacity, for 2018 through 2027; he provided a review of historical and projected fossil unit availability; and Tier 2 plant retirement. Finally, Mr. Paul provided an overview of the proposed CHP facility at the Ford R&E center and supported fossil generation expenses to be included in the IRM. Mr. Paul sponsored Exhibit A-6, Schedules F1 and F2; Exhibit A-12, Schedule B5.1; Exhibit A-13, Schedules C5.1, C5.4, and C5.5; Exhibit A-30, Schedule T3; and Exhibit A-41, Schedule EE1 through EE3. Mr. Paul's revised direct testimony and revised rebuttal testimony are transcribed at 4 Tr 512 through 607. As noted above, a portion of Mr. Paul's testimony and part of one exhibit were stricken. Cross-examination of Mr. Paul begins at 4 Tr 609 and continues through 4 Tr 684.

Heather D. Rivard, Senior Vice President of Distribution Operations for DTE Energy Corporate Services, testified regarding the company's expanded tree-trimming program and provided details concerning historical and projected tree-trimming O&M expense. Ms. Rivard sponsored Exhibit A-13, Schedule C5.6 and Exhibit A-22 Schedule L1 Revised. Ms. Rivard's revised direct testimony and revised rebuttal testimony are transcribed at 3 Tr 194 through 253. Cross-examination of Ms. Rivard begins at 3 Tr 254 and continues through 3 Tr 279.

Camilo Serna, Vice President of Corporate Strategy for DTE Energy Corporate Services, provided an overview of transportation electrification in Michigan, including DTE Electric's role in electrification efforts, and testified in support of DTE Electric's proposed DG tariff. Mr. Serna sponsored Exhibit A-12, Schedule B5.9; Exhibit A-16, Schedule F11; Exhibit A-27, Schedule Q1; and Exhibit A-34, Schedules X1-X5. Mr. Serna's direct testimony and rebuttal testimony are transcribed at 8 Tr 3539 through 3679. Cross-examination of Mr. Serna can be found at 8 Tr 3680 through 8 Tr 3788.

Kenneth L. Slater, Manager of Revenue Requirements in the Regulatory Affairs section of DTE Energy Corporate Services, testified regarding DTE Electric's historical and projected revenue deficiency, including detail on the revenue requirements for the expanded tree-trimming program and the calculation of the incremental revenue for the proposed IRM. Mr. Slater sponsored Exhibit A-1, Schedule A1; Exhibit A-2, Schedule B1; Exhibit A-3, Schedules C2, C12, and C13; Exhibit A-4, Schedule D1; Exhibit A-11, Schedule A1; Exhibit A-12, Schedule B1; Exhibit A-13, Schedules C2, C14, and C16; Exhibit A-14, Schedule D1; Exhibit A-22, Schedules L1(Revised) and L2; and Exhibit A-30, Schedules T5 through T7 and T11 through T13. Mr. Slater's testimony is transcribed at 5 Tr 1498 through 1522.

Edward J. Solomon, Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy Company, testified concerning the company's projected capital structure and the cost of short- and long-term debt. In addition, Mr. Solomon provided support for the company's proposal to securitize unamortized costs associated with its tree-trimming program. Mr. Solomon sponsored Exhibit A-1, Schedule A2; Exhibit A-4, Schedules D2 through D5; Exhibit A-11, Schedule A2; Exhibit A-14, Schedules D1.1 through D1.3 and D2 through D4; and Exhibit A-18, Schedules H1 and H2. Mr. Solomon's direct and rebuttal testimony are transcribed at 5 Tr 1032 through 1065. Cross-examination of Mr. Solomon begins at 5 Tr 1066 and ends at 5 Tr 1116.

Teresa M. Uzenski, Manager of Regulatory Accounting for DTE Energy Corporate

Services, supported historical and projected financial information for DTE Electric, including projected operating income and the company's treatment of non-service components of pension and OPEB. Ms. Uzenski also supported corporate staff group (CSG) capital and O&M expenses and the inclusion of Customer 360 post-implementation expenses in the regulatory asset for these expenses. Ms. Uzenski addressed proposed regulatory asset treatment for EV infrastructure, ADMS, and tree-trimming. Finally, Ms. Uzenski described the proposed accounting treatment for the IRM. Ms. Uzinski sponsored Exhibit A-2, Schedules B3 through B5.1, B6 through B6.2, and B7; Exhibit A-3, Schedules C1 through C1.1, C3 through C6, C11, and C14 through 19; Exhibit A-12, Schedules B2 through B4.3, B5, and B5.8; Exhibit A-13, Schedules C1, C3, C5, C5.9, C5.13, C5.15, C5.17, C6, and C11 through C13; Exhibit A-22, Schedule L.3; and Exhibit A-30, Schedule T1. Ms. Uzenski's direct and rebuttal testimony are transcribed at 7 Tr 3273 through 3358. Cross-examination of Ms. Uzenski begins at 7 Tr 3359 and ends at 7 Tr 3384.

Michael J. Vilbert, Principal Emeritus of the Brattle Group, estimated the cost of capital for DTE Electric, specifically providing an ROE estimate for the company for the test year. Dr. Vilbert sponsored Exhibit A-4, Schedules D5.1 through D5.19. Dr. Vilbert's direct testimony and rebuttal testimony (including Appendices A and B) are transcribed at 6 Tr 1912 through 2056. Cross-examination and redirect of Dr. Vilbert begins at 6 Tr 2057 and ends at 6 Tr 2070.

Sherri L. Wisniewski, Director of Tax Operations for DTE Energy Corporate Services, testified regarding historical and projected federal income tax (FIT), Michigan Corporate Income Tax (MCIT), local income taxes, and property taxes for DTE Electric.

Ms. Wisniewski's direct and rebuttal testimony are transcribed at 5 Tr 1524 through 1547.

Richard J. Mueller, DTE Electric's Manager of Engineering Standards and Technology, provided rebuttal testimony on DTE Electric's proposed DG tariff. Mr. Mueller sponsored Exhibit A-43, Schedules GG1 and GG2. Mr. Mueller's rebuttal testimony is transcribed at 8 Tr 3792-3817. Cross examination of Mr. Mueller begins at 8 Tr 3818 can continues through 8 Tr 3850.

B. Staff

Julie K. Baldwin, Manager of the Renewable Energy Section of the Commission's Energy Resources Division, testified regarding the Staff's recommendations related to modification of DTE Electric's proposed Rider 18, Rider DG, and Rider 16. Ms. Baldwin sponsored Exhibits S-11.0; S-11.1; and S-11.2. Her testimony is transcribed at 8 Tr 4166 through 4178.

Brad B. Banks, Departmental Analyst in the Energy Waste Reduction Section of the Commission's Energy Resources Division, testified regarding potential benefits that could be achieved in DTE Electric's customer service low income programs by aligning these programs with the company's energy waste reduction (EWR) programs. Mr. Banks' testimony is transcribed at 8 Tr 4202 through 4208.

Jonathon J. Decooman, a Public Utilities Engineer in the Generation and Certificate of Need Section of the Commission's Energy Resources Division, testified regarding the Staff's adjustments to capital expenditures in the categories of Steam Power Generation-Non-Routine: Environmental; Other Power Generation-Non-Routine: CHP Plant; and Other Power Generation- Non-Routine Combined Cycle (CC) – 2022. Mr. Decooman sponsored exhibits S-13.0 through S-13.7, and confidential Exhibit S-13.8.

His testimony is transcribed at 8 Tr 4181 through 4200.

Karen M. Gould, an Auditor in the Energy Waste Reduction Section of the Commission's Energy Resource Division, provided an update on the Staff's engagement with stakeholders on EWR savings effects on sales forecasting. Ms. Gould sponsored Exhibits S-14.0 and S-14.1. Her testimony can be found at 8 Tr 4210 through 4217.

Robert G. Ozar P.E., Assistant Director of the Commission's Energy Resources Division testified regarding DTE Electric's proposed Charging Forward program and the company's proposed DG Rider 18. His testimony is transcribed at 8 Tr 3406 through 3437. Cross-examination of Mr. Ozar begins at 8 Tr 3438 and ends at 8 Tr 3457.

Nicholas M. Evans, a Public Utilities Engineering Specialist in the Electric Operations Section of the Commission's Energy Operations Division, testified concerning the Staff's adjustments to DTE Electric's projected capital expenditures and O&M expenses for its distribution system. Mr. Evans also recommended reporting requirements and suggested an alternative to the company's tree-trimming proposal. Mr. Evans sponsored Exhibits S-10.0 through S-10.7. His testimony can be found at 8 Tr 4094 through 4132.

Ryan Laruwe, a Public Utilities Engineering Specialist in the Commission's Energy Operations Division, testified regarding the Staff's recommendation on the approval of the company's proposed IRM. His testimony is transcribed at 8 Tr 4157 through 4164.

Cody Matthews, a Public Utilities Engineer in the Smart Grid Section of the Commission's Energy Operations Division, testified regarding the Staff's recommendations concerning expense recovery for DTE Electric's AMI program, demand response (DR) programs, summer on-peak rates, information technology (IT) meter reading, and contingency. Mr. Matthews sponsored Exhibits S-12.0 through S-12.4. His testimony is available at 8 Tr 4134 through 4155.

Michelle L. Edelyn, an Auditor in the Revenue Requirements Section of the Commission's Regulated Energy Division, testified regarding the Staff's total rate base projection for the test year, including working capital and depreciation and amortization expense. Ms. Edelyn sponsored Exhibits S-2, Schedules B1 and B4; and Exhibits S-7.0 through S-7.5. Her testimony is transcribed at 8 Tr 4033 through 4042.

Jay S. Gerken, Manager of the Rate Base Unit in the Revenue Requirements Section of the Commission's Regulated Energy Division, testified regarding DTE Electric's accounting requests related to TOU rate implementation, and Charging Forward program. Mr. Gerken also testified regarding the Staff's recommendation for allowance for funds used during construction (AFUDC) and test year operating income. Mr. Gerken sponsored Exhibit S-9.0, and his testimony can be found at 8 Tr 4052 through 4059.

Daniel J. Gottschalk, the Electric Cost of Service Specialist in the Rates and Tariffs Section of the Commission's Regulated Energy Division, presented the Staff's class cost of service study (COSS) based on the Staff's recommended revenue requirement. Mr. Gottschalk also addressed the Staff's recommended residential and commercial secondary customer charges; capacity cost revenue requirement; residential income assistance (RIA) provision; senior citizen credit; and power supply cost recovery (PSCR) base. Mr. Gottschalk sponsored Exhibit S-6, Schedules F1.1 through F1.4; and Exhibit S-18. Mr. Gottschalk's testimony is available at 8 Tr 4261 through 4275.

Kevin S. Krause, and Auditor in the Rates and Tariffs Section of the Commission's Regulated Energy Division, provided the Staff's position on DTE Electric's proposed DG tariff, Rider 18, along with the Staff's views on cost-of-service and rate design for electric vehicles and standby tariffs. Mr. Krause sponsored Exhibit S-17. His direct and rebuttal testimony are transcribed at 8 Tr 4229 through 4259.

Theresa McMillan-Sepkowski, an Audit Specialist in the Revenue Requirements Section of the Commission's Regulated Energy Division, testified concerning the Staff's adjustments to DTE Electric's proposed employee incentive compensation plan (EICP) costs. Her testimony is transcribed at 8 Tr 4044 through 4050.

Kirk D. Megginson, a Financial Specialist in the Revenue Requirements Section of the Commission's Regulated Energy Division, provided the Staff's recommendations for DTE Electric's test year capital structure, return on common equity (ROE) and overall rate of return. Mr. Megginson sponsored Exhibit S-4, Schedules D-1 (revised) through D-5. Mr. Megginson's testimony is transcribed at 8 Tr 4061 through 4092.

Robert D. Nichols II, CPA Manager of the Revenue Requirements Section of the Commission's Regulated Energy Division, presented the Staff's test year revenue deficiency, net operating income and an adjustment to excess deferred income taxes (DFIT) for DTE Electric. Mr. Nichols sponsored Exhibit S-1, Schedule A1; Exhibit S-3, Schedules C1, C1.1, C14, and C15; and Exhibit S-15. Mr. Nichols' testimony is transcribed at 8 Tr 4013 through 4020.

Mark J. Pung, a Departmental Analyst in the Rates and Tariff Section of the Commission's Regulated Energy Division, testified regarding the Staff's recommendations for present revenue, rate design and proposed tariff changes. Mr. Pung sponsored Exhibit S-3, Schedule C3 and Exhibit S-6, Schedules F2, F3, F5, and F6. His direct and rebuttal testimony is available at 8 Tr 4277 through 4292.

Nicholas M. Revere, the Manager of the Rates and Tariff Section of the Commission's Regulated Energy Division, provided the Staff's position on DTE Electric's proposed Weekend Flex and Fixed Bill Pilots, certain proposals related to summer on-peak rates, and the Staff's calculation of unbundled transmission rates for Rider 18. Mr. Revere sponsored Exhibits S-6, Schedule F3; S-16.1 through S-16.3. His testimony is available at 8 Tr 4294 through 4303.

Brian Welke, Manager of the Income Analysis Unit in the Commission's Regulated Energy Division, provided the Staff's projection of other O&M expense for the test year. Mr. Welke further testified regarding the Staff's recommended uncollectibles expense, injuries and damages expense, inflation, healthcare expense, and an active healthcare credit. Mr. Welke sponsored Exhibit S-3, Schedules C5 and C5.1 through C5.3. His testimony is transcribed at 8 Tr 4022 through 4030.

Heather Cantin, a Department Analyst in the Resource Adequacy and Retail Choice Section of the Energy Resource Division provided Staff's response to the proposed changes to DTE's Retail Access Service Rider (RASR) made by Energy Michigan. Her rebuttal testimony is transcribed at 8 Tr 4219 through 4227.

C. Attorney General

Sebastian Coppola, an independent business consultant testified on behalf of the Attorney General. Mr. Coppola performed an independent analysis of DTE Electric's filing in this proceeding, providing specific recommendations with respect to O&M expense, EICP, employee benefits, capital expenditures and rate base, cost of capital, working capital, the Charging Forward program, DTE Electric's proposed IRM, rate design issues, and the Weekend Flex and Fixed Bill pilot programs. Mr. Coppola sponsored Exhibits

AG-1 through AG-33. His testimony (including Appendix A) is found at 5 Tr 1586 through 1704.

D. ABATE

James R. Dauphinais, Managing Principal with Brubaker and Associates, Inc., testified regarding DTE Electric's COSS and rate design related to Rider 3 (standby service) and the company's proposed state reliability mechanism (SRM) capacity charge update. Mr. Dauphinais also testified concerning the allocation of costs for the proposed Charging Forward program. Mr. Dauphinais sponsored Exhibits AB-1 and AB-2. His direct testimony and rebuttal testimony are transcribed at 6 Tr 1729 through 1785. Cross-examination of Mr. Dauphinais begins at 6 Tr 1786 and ends at 6 Tr 1802.

Michael P. Gorman, a Managing Principal with Brubaker and Associates, Inc., testified regarding ABATE's adjustments to DTE Electric's proposed revenue increase, with a focus on adjustments to the company's regulatory plan for coal unit retirements, working capital related to a prepaid pension asset, and O&M inflation. Mr. Gorman also addressed the company's proposed IRM. Mr. Gorman sponsored Exhibits AB-33, AB-34, AB-35, and AB-36. His direct and rebuttal testimony can be found at 7 Tr 2897 through 2947.

Brian C. Andrews, a Senior Consultant in public utility regulation with Brubaker & Associates, Inc., testified regarding DTE Electric's voltage level discounts for Rate D11 and the company's nuclear surcharge. Mr. Andrews sponsored Exhibits AB-3, AB-4, AB-5, AB-6, AB-7, AB-8, AB-9, AB-10, AB-11, AB-12, AB-13, and AB-14. His direct and rebuttal testimony is transcribed at 7 Tr 2845 through 2872. Cross-examination of Mr. Andrews can be found at 7 Tr 2873 through 7 Tr 2895.

Christopher C. Walters, a consultant in public utility regulation with Brubaker & Associates, Inc., testified regarding an appropriate ROE and overall rate of return for DTE Electric. Mr. Walters sponsored Exhibits AB-15 through AB-32. His direct and rebuttal testimony can be found at 7 Tr 2949 through 3031.

E. <u>MEC/NRDC/SC and EIBC/IEI</u>

MEC/NRDC/SC and EIBC/IEI jointly filed the testimony and exhibits of Douglas B. Jester, a Partner of 5 Lakes Energy LLC. Mr. Jester testified on behalf of MEC/NRDC/SC regarding performance considerations in setting DTE Electric's ROE and approving employee incentive compensation; the company's proposal to accelerate spending on distribution; the proposed IRM; a proposal to reform the Service Quality Rules; allocation of production costs; residential rate design, including the Fixed Bill and Weekend Flex pilots; and recommended changes to Rider 18. Mr. Jester testified on behalf of MEC/NRDC/SC and EIBC on the Charging Forward program, and he testified on behalf of EIBC regarding Rider 3. Mr. Jester sponsored Exhibits MEC-1 through MEC-8, and his revised direct and rebuttal testimony can be found at 6 Tr 2145 through 2266. Cross-examination of Mr. Jester is transcribed at 6 Tr 2267 through 6 Tr 2278.

F. <u>MEC/NRDC/SC</u>

Christopher Villarreal, President of Plugged In Strategies, testified regarding DTE Electric's planned investments in its distribution system, the company's 5-Year Distribution Plan, and the IRM. Mr. Villarreal sponsored Exhibits MEC-9 through MEC-12. His testimony is transcribed at 7 Tr 2758 through 2791. Cross-examination of Mr. Villarreal is transcribed at 7 Tr 2792 through 7 Tr 2841.

Karl M. Rábago, the principal of Rábago Energy LLC, testified regarding DTE

Electric's proposal to increase fixed customer charges for residential customers (Rate D1) and small commercial customers (Rate D3). Mr. Rábago also addressed the company's proposed Rider 18 and the inclusion of dues paid to the Edison Electric Institute (EEI) in rates. Mr. Rábago sponsored Exhibits MEC-13 through MEC-20 and MEC-22 through MEC-31. His testimony is available at 6 Tr 2464 through 2528.

Robert M. Fagan, a Principal Associate at Synapse Energy Economics, testified regarding the IRM, including resource adequacy issues and retirement of DTE Electric's Tier 2 units. Mr. Fagan sponsored Exhibits MEC-32 through MEC-42, Confidential Exhibit MEC-43, and Exhibits MEC-44 through MEC-50. His testimony is transcribed at 6 Tr 2530 through 2552.

Avi Allison, a Senior Associate with Synapse Energy Economics, evaluated the historical and projected economic performance of DTE Electric's coal unit fleet, with a specific focus on River Rouge Unit 3 and on the St. Clair Units 1-3 and 6-7. Mr. Allison sponsored Exhibits MEC-63 through MEC 105. His testimony can be found at 6 Tr 2587 through 2627.

Max Baumhefner, a senior attorney with the Natural Resources Defense Council, testified on behalf of MEC/NRDC/SC and EC regarding the Charging Forward program. Mr. Baumhefner sponsored Exhibits MEC-51 through MEC-62. His testimony is transcribed at 6 Tr 2554 through 2584.

George E. Sansoucy, owner of George E. Sansoucy, P.E., LLC, testified on behalf of MEC regarding DTE Electric's proposed CHP plant transaction. Mr. Sansoucy sponsored Exhibits MEC-106 through MEC-111. His testimony is transcribed at 6 Tr 2677 through 2688.

G. Environmental Law and Policy Center *et al*.

William Kenworthy, Regulatory Director, Midwest for Vote Solar, testified concerning DTE Electric's proposed Rider 18 and presented a counter-proposal for a DG tariff. Mr. Kenworthy sponsored Exhibits ELP-1 through ELP-7. His testimony is transcribed at 6 Tr 2317 through 2375.

Kevin Lucas, Director of Rate Design at the Solar Energy Industries Association, testified about aspects of DTE Electric's rate case, with a specific focus on the treatment of DG resources and Rider 18. Mr. Lucas sponsored Exhibits ELP-10 through ELP-51. His direct and rebuttal testimony are transcribed at 6 Tr 2377 through 2461.

H. Michigan Energy Innovation Business Council and Institute for Energy Innovation

Jamie Scripps, a partner with 5 Lakes Energy LLC, discussed the importance of CHP systems in Michigan and the relationship between CHP development and standby rates. Ms. Scripps also testified concerning the impacts of DTE Electric's proposed changes to Rider 3. Ms. Scripps sponsored Exhibits EIB-1 through EIB-4, and her testimony can be found at 8 Tr 3459 through 3486. Cross examination of Ms. Scripps begins at 8 Tr 3487 and continues through 8 Tr 3512.

Laura Sherman, a senior consultant with 5 Lakes Energy LLC, testified on the impacts of DTE Electric's proposed Rider 18 on DG customers and the advanced energy industry in Michigan. Ms. Sherman sponsored Exhibits EIB-5 through EIB-7. Her testimony is available at 8 Tr 3515 through 3534.

I. Energy Michigan

Andrew J. Zakem, an independent consultant on utility regulatory matters, testified regarding DTE Electric's computation of capacity and non-capacity costs, and on changes to the company's electric choice tariff, Rider EC2. His testimony is transcribed at 7 Tr 3073 through 3102.

J. Great Lakes Renewable Energy Association

Robert Rafson, owner of Chart House Energy, LLC, testified regarding potential impacts and pricing signals from proposed Rider 18 along with recommended modifications to the tariff. Mr. Rafson sponsored Exhibits GLREA-1 And GLREA-2. His testimony is transcribed at 8 Tr 3993 through 4010.

Geoffrey C. Crandall, Principal and Vice President of MSB Energy Associates, Inc., testified regarding proposed changes to Rider 16 and Rider 18. Mr. Crandall sponsored Exhibits GLREA-3 through GLREA-6. His testimony is transcribed at 8 Tr 3978 through 3992.

K. Soulardarity

Jackson Koeppel, the Executive Director of Soulardarity, testified regarding Rider 18, including the benefits of providing access to solar-powered DG for low-income customers. Mr. Koeppel also addressed concerns about DTE Electric's rate structure, safety and reliability, and customer service. Mr. Koeppel sponsored Exhibits SOU-1a, SOU-1b, SOU-1c, SOU-1d, and SOU-2 through SOU-23. His testimony is transcribed at 5 Tr 1550 through 1582.

L. ChargePoint

James Ellis, Senior Director of Utility Solutions for ChargePoint, testified in support of the overall goals of DTE Electric's Charging Forward program. Mr. Ellis also made recommendations for protecting utility investments as the market for EV charging continues to develop and for creating a program advisory council. Mr. Ellis sponsored Exhibit CP-1. His direct and rebuttal testimony can be found at 7 Tr 3035 through 3071.

M. Kroger

Justin Bieber, a Senior Consultant at Energy Strategies, LLC, testified regarding DTE Electric's rate design for primary voltage customers; the company's method for computing the SRM; service reliability; the proposed IRM; and the inclusion of inflation in calculating test year O&M expense. His direct and rebuttal testimony are transcribed at 7 Tr 2706 through 2754.

N. Walmart

Gregory W. Tillman, Senior Manager, Energy Regulatory Analysis for Walmart, testified about the overall rate increase requested in this case, including the need to consider DTE Electric's reduced risk when setting ROE. Mr. Tillman also testified regarding the production cost allocator proposed by the company, the rate design for Rate D11, and the IRM. Mr. Tillman sponsored Exhibits Wal-1 through Wal-4, and his testimony can be found at 8 Tr 3913 through 3936.

III.

TEST YEAR

DTE Electric selected the calendar year ending December 31, 2017, to serve as its historical test year. This test year was then normalized and adjusted to arrive at a May 1, 2019 to April 30, 2020 projected test year for the purpose of setting rates. No party objected to the company's proposed test period in testimony. However, in its initial brief, the RCG recommends that the Commission adopt the 2017 historical test year updated for known and measurable changes from the Tax Cut and Jobs Act (TCJA) and the rate relief from DTE Electric's last rate case, Case No. U-18255.

The RCG argues that the company's projected test year, which extends to 22 months after the company's filing, may not fall within the time limits for projections contained in MCL460.6a(1), noting that "[a] reasonable interpretation of the statute is that a projected test year for purposes of this case would be for the 12 consecutive months after DTE's rate filing on July 6, 2018."[4] The RCG further argued that the company's long-term projection is based on unreliable forecasts, which may significantly overstate the company's revenue deficiency. According to the RCG, these concerns could be addressed through the use of updated historical information, and that the annual filing of rate cases by DTE Electric actually supports the use of an historical test year "as a check upon whether the repeated rate case filings based on projected test years are resulting in a permanent escalation of rates, and without even a pause to determine whether customer rates are just and reasonable."[5]

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[4] RCG's initial brief, p. 3.
[5] Id.

In its reply brief, DTE Electric points out that the RCG's proposal is contrary to well-established practice in rate case proceedings.

MCL 460.6a(1) provides that "A utility may use projected costs and revenues for a future consecutive 12-month period[6] in developing its requested rates and charges." The plain language of this section does not require the other parties or the Commission to fully rely on the projected costs and revenues determined by the utility, as the Commission has repeatedly recognized:

> In a case where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections. Given the time constraints under Act 286, all evidence (or sources of evidence) in support of the company's projections should be included in the company's initial filing. If the Staff or intervenors find insufficient support for some of the utility's projections they may endeavor to validate the company's projection through discovery and audit requests. If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data) the Staff, intervenors, or the Commission may choose an alternative method for determining the projection.[7]

And,

> The Commission rejects [the] assertion that simply because an amount is projected, it must therefore be granted lest the Commission violate the utility's statutory right to rely on projections. In the statute providing for the use of a projected test year, nothing eliminated the requirement that all rate increases must be shown to be just and reasonable. MCL 460.6a(1); see, also, MCL 460.6, 460.54, and 460.551 et seq. The same statutory section that allows for use of projected costs also requires that the "utility shall place in evidence facts relied upon to support the utility's petition or application to increase its rates." MCL 460.6a(1). The ALJ observed that her recommendations do not preclude the company from seeking

[6] The use of the indefinite article "a" in "a future consecutive 12-month period" does not limit the projection to the 12-month period immediately following the filing of the rate case, as the RCG suggests (although a utility could set the test period in that manner). While not an issue that is before the Commission in this case, the ALJ nevertheless observes that because rates are being set on the basis of costs and revenues projected to occur in a future period, any rate increase or decrease could not be implemented until the beginning of that future period. Thus, if a utility files a case on January 1, 2020, using a test period that begins on January 1, 2021, new rates, if established after a full contested case (and not in a settlement agreement), could not be implemented until January 1, 2021, even though a Commission order would be due by October 31, 2020.

[7] January 11, 2010 order in Case No. U-15768, pp. 9-10.

> environmental capital expenditures in its next rate case that were also sought in this rate case. That is not a holding, or a suggestion. Whether Consumers chooses to do so is entirely in the utility's discretion. Whenever it chooses to do so, however, if the utility realistically expects inclusion of the total projected costs, it must supply the Commission with enough evidence to support a finding that the costs are just and reasonable – in the absence of thorough, detailed, and meaningful evidence, the Commission's hands are tied.[8]

Consistent with the above-quoted directives from the Commission, it is this ALJ's observation that for certain items, the parties have relied on historical information as "an alternative method for determining the projection[,]" and that these estimates, based on past spending, have often been found to be more reasonable and accurate than the utility's projection. Thus, in every rate case, historical information continues to play a role in determining just and reasonable rates.

The RCG also raises a concern about "pancaking" utility cases,[9] such that, new projected costs and revenues are being addressed <u>before</u> the test year from the previous rate case has ended. This, too, has been addressed by the Commission:

> The Commission also finds unavailing Consumers' argument about its need to spend conservatively because of the timing of the final order in its last rate case. Consumers not only decides the test year, but it also decides when it will file its next rate case. Thus, if the company chooses to underspend on certain programs in light of uncertainty about final rate relief, any disallowance that may be proposed or approved in a subsequent rate case due to prior underspending/over projection of cost estimates can only be attributed to the company's actions.[10]

Ultimately, the RCG's request to use an updated historical test year for setting rates in this proceeding should be rejected. The RCG raises this recommendation for the

[8] June 12, 2012 order in Case No. U-16794, p. 13.
[9] Technically, "pancaking" of utility rate cases occurs when a new rate case is filed while a final order in the previous rate case is still pending. MCL 460.6a(6) provides, "A utility may not file a new general rate case application until the commission has issued a final order on a prior general rate case" thus precluding pancaking.
[10] February 28, 2017 order in Case No. U-17990, p. 18.

first time in its initial brief, citing information from the company on the historical test year balances, but it fails to provide any additional calculations of the known and measurable changes from the TCJA or the rates approved in Case No. U-18255. Even had the RCG done so, the parties would have had no reasonable opportunity to respond. Accordingly, this ALJ recommends the adoption of a May 1, 2019 to April 30, 2020 test period for setting rates in this proceeding.

IV.

RATE BASE

A utility's rate base consists of the capital invested in used and useful utility plant, plus the utility's working capital requirements, less accumulated depreciation. In its application, DTE Electric projected a total electric rate base of $17,172,558,000, adjusted to $17,156,659,000 in the company's brief, and adjusted again to $17,152,348,000 in its reply brief. The Staff calculated a rate base of $16,959,893,000 for the test year. The Staff adjusted this amount to $17,051,324,000 in its initial brief. The Attorney General and MEC/NRDC/SC also made specific adjustments to certain utility plant items that are discussed below.

O. Net Plant

In its reply brief, DTE Electric projected a revised net plant amount of $15,561,085. The Staff projected net plant of $15,460,855 in its initial brief. The Staff and other parties to the proceeding raised issues concerning fossil generation, contingency amounts included in capital expense, distribution operations expense, DSM, IT, Corporate Staff Group capital expense, and working capital. These issues are addressed below.

1. Capital Contingency Amounts

DTE Electric included contingency capital expenditures of $4.5 million for the company's proposed Energy Center. Consistent with the Staff's and Attorney General's objections, the company removed this amount for Energy Center contingency in its initial brief. DTE Electric also included $10.5 million in contingency as part of the costs associated with the construction of a new natural gas combined cycle (NGCC) plant.[11] Mr. Coppola and Mr. DeCooman recommended removal of NGCC contingency amounts.[12] According to Mr. Coppola, although the $951.8 million approved for the NGCC plant includes contingency, "it is clear from the Commission order that only actual costs are to be included in rates."[13] The Staff pointed out that "[d]isallowance of the projected contingency costs in this case does not preclude the Company from recovering these costs in a future filing, once they have been incurred. Therefore, the disallowance of these costs is not premature, as the Company has asserted."[14] Although not providing testimony on this issue, MEC/NRDC/SC and the RCG also objected to the inclusion of contingency amounts in their briefs.

In response, DTE Electric argues that the Commission's order in Case No. U-18419 included $17.8 million for contingency, and "because the Company is only requesting to recover approximately two-thirds of the total pre-approved project costs

[11] The NGCC plant and associated costs were approved in the April 27, 2018 order in Case No. U-18419.
[12] 5 Tr 1624-1626; Exhibit AG-12, 8 Tr 4196-4199; Exhibit S-13.9.
[13] 5 Tr 1625.
[14] Staff's initial brief, p. 11.

(approximately $650 million) in this case, it would be premature to disallow a portion of the approved funding."[15]

As noted above, in its initial brief, the company removed $4.5 million in contingency for the proposed Energy Center, and this PFD agrees with the Staff and the Attorney General that an additional $10.5 million in contingency costs for the NGCC plant should be disallowed. As the Commission has repeatedly found, contingency amounts are too speculative to be included in rates, and it is unjust and unreasonable to shift the risk associated with contingency onto ratepayers, allowing a utility to earn a return of and on costs that are of an indeterminate amount or that may never be incurred. Further, as has been pointed out repeatedly, including contingency amounts in rate base may dampen the company's incentive to control costs.

Although the order approving the NGCC included some allowance for contingency, only actual costs were approved for inclusion in rate base, as Mr. Coppola pointed out. Accordingly, the Commission should disallow a total of $15,003.00 in contingency for the Energy Center and the NGCC plant. The Staff calculated this would reduce rate base by $11,134,000. In its initial brief, the company stated that it made an adjustment of $114,000 in depreciation reserve related to the NGCC contingency and a $3.2 million reduction in plant in service related to the same contingency amounts.[16]

2. Steam, Hydraulic, Fossil, and Other Power Generation

As shown in Exhibit A-12 Schedule B5, DTE Electric projects routine and non-routine capital expenditures for steam, hydraulic, and other production plant totaling

[15] DTE Electric's reply brief, p. 11.
[16] DTE Electric's reply brief, p. 8 fn 15.

approximately $2.1 billion from the end of the 2017 historical test year through the projected 2019-2020 test year.

The Staff and the Attorney General recommend disallowing certain costs associated with the Monroe dry fly ash projects. MEC/SC/NRDC recommend that the Commission exclude both projected capital expenditures and O&M expense associated with River Rouge Unit 3 as well as capital expenditures for St. Clair Units 1, 2, 3, and 6. The Attorney General and MEC also recommend that the Commission disallow costs for a proposed CHP plant at the Ford R&E facility. Only these contested issues are addressed in detail.

a. <u>Monroe Dry Fly Ash Processing Project</u>

Mr. Paul described the process for planning capital expenditures for production plant noting that projects are initiated to support safety, regulatory requirements, environmental compliance, and engineering recommendations. Mr. Paul further explained that "Capital expenditure requests require the initiation of an approved project form that includes a detailed explanation of the project and an initial estimate of the costs and benefits associated with the project."[17] Projects are then further developed and refined with the timing of the actual work based substantially on planned outage schedules for each plant.[18] Once plans are fully developed and prioritized, they are submitted for management approval. Depending on the estimated cost of the project, higher levels of management approval are required.[19]

With respect to the Monroe dry fly ash project, Mr. Paul explained that the project

[17] 4 Tr 539.
[18] Id. at 540.
[19] 4 Tr 541-542.

is comprised of: (1) Monroe dry fly ash basin, “a project required to maintain the exterior slope of the onsite fly ash landfill berm;” (2) Monroe fly ash basin vertical extension, which “represents a project to expand the storage capabilities at the existing fly ash basin to begin storing dry fly ash while meeting the coal combustion residuals (CCR) requirements;” (3) Monroe CCR transfer pad, which represents a project needed to build a new concrete storage containment pad that allows for storage of fly ash until it can be transported to a landfill;” (4) Monroe ELG fly ash dry conversion, which “represents a project required to convert the existing wet fly ash transport system . . . to a dry fly ash transport system in accordance with EPA’s fly ash Effluent Limitation Guidelines (ELG) rule promulgated in 2015 requiring all fly ash transport systems be dry by 2023;” and (5) Monroe dry fly ash processing, which:

> Represents a project intended to reduce the amount of fly ash that will need to be transported from Monroe Power Plant to the onsite landfill. Ash processing will allow for fly ash with high carbon content to be treated and turned into an acceptable product for use in concrete manufacturing. Reducing the amount of fly ash placed in the landfill will minimize cost increases related to the new environmental requirements.[20]

Mr. DeCooman testified that several of the dry fly ash projects described by Mr. Paul are related to the ELG that were revised in 2015. According to Mr. DeCooman:

> The ELG establishes a zero-discharge limit for pollutants in wastewater streams from steam generation plants, achieved by using a dry ash handling system. The Monroe plant’s current method for removal and storage of its fly ash is to use a wastewater stream to sluice this ash from its collection point to a storage facility, thus creating polluted wastewater. Line item 2 is a project to construct a new storage basin for the dry fly ash. The Company provided a detailed description of line items 3-6 in a response to a Staff audit request.[21]

[20] 4 Tr 546-547; Exhibit A-12, Schedule B5.1, p. 2 lines 2-6.
[21] 8 Tr 4185.

Mr. DeCooman explained that the projects listed in lines 2-5 of Exhibit A-12, Schedule B5.1, p. 2 are "directly related to the conversion of the fly ash transfer system at the Monroe power plant from a wet transport system to a dry transport system," noting that these specific projects should be approved because they "are necessary to meet portions of the ELG that relate to the transport of fly ash and must be met by December 31, 2023."[22] However, Mr. DeCooman questioned the inclusion of $34,100 capital costs associated with the Monroe dry fly ash processing project.[23]

Mr. DeCooman testified that the dry fly ash processing project is designed to allow most of the fly ash to be diverted, further processed, and then sold to concrete manufacturers. The project will allow for the burning of higher carbon, lower cost, petroleum coke (pet coke) while producing fly ash that can be used in the manufacture of concrete.[24] Mr. DeCooman testified that, in response to Staff audit requests, DTE Electric provided a project management planning document and a net present value of the revenue requirement (NPVRR) analysis for the project under different scenarios.[25] Mr. DeCooman found that while the assumptions used for the NPVRR were reasonable for benchmarking purposes,

> [I]t should be noted that the NPVRR results presented may be misleading; it is Staff's understanding that the NPVRR results are being compared to a scenario where neither the sale of marketable fly ash, nor the cost savings from using cheaper pet coke, were included. For an NPVRR analysis that properly represents the impact of this project on the Company's rate base, all incremental costs and savings beyond the current operating state that result from this project would need to be included in this calculation.[26]

[22] Id. at 4186, 4190.
[23] Exhibit A-12, Schedule B5.1, p. 2, line 6.
[24] 8 Tr 4186.
[25] 8 Tr 4187; Exhibits S-13.1 and S-31.2.
[26] 8 Tr 4188.

Mr. DeCooman continued, explaining that as of October 1, 2018, DTE Electric had not received full internal approval of the project, nor had the company executed an engineering, procurement, and construction (EPC) contract or even determined a contracting strategy. Mr. DeCooman testified that although the Staff was not discouraging DTE Electric from pursuing the Monroe dry fly ash processing project, given the uncertainty about the project costs and benefits at this time, the Staff recommended disallowing $9.433 million in the 16-month bridge period and $24.667 million in the projected test year.[27] Mr. DeCooman also recommended that the company be directed to engage in technical discussions with the Staff to allow for better understanding of the company's NPVRR inputs and analysis.[28]

Mr. Coppola testified that in 2015, the Environmental Protection Agency (EPA) promulgated the ELG regulations; however, under the new federal administration, the ELGs are under review and may be revised. In light of the likely revision to the rules, Mr. Coppola recommended, in addition to the Staff's proposed adjustment, amounts for "Monroe Dry Ash Fly Conversion"[29] and "Monroe Inactive Impoundment Remediation"[30] should also be disallowed pending the outcome of the ELG revisions. The Attorney General's recommended disallowance totaled $90.9 million.

In rebuttal to the Staff, Mr. Paul testified that the company has received internal approvals for the Monroe dry fly ash project and has completed benchmarking and conceptual design activities. Mr. Paul added that the project is reasonable and prudent because it will reduce PSCR costs for ratepayers and will help meet the company's

[27] 8 Tr 4189-4191.
[28] 8 Tr 4192.
[29] Exhibit A-12, Schedule B5.1, page 2, line 5.
[30] Id. at line 18.

environmental goals by diverting fly ash waste to a beneficial use.[31]

In response to the Attorney General's proposed disallowances, Mr. Paul explained that the specific rules governing the Monroe ELG fly ash dry conversion project are not being reconsidered and the project is still subject to the compliance deadline under the ELG. In addition, neither the Monroe impoundment remediation project nor the dry fly ash processing project are subject to the ELG rules, and therefore any reconsideration of the rules is not relevant to the need for these projects.[32] In its initial brief, the Staff agreed with Mr. Paul that, with respect to the Monroe impoundment remediation project and the dry fly ash conversion project Mr. Coppola's testimony should be given no weight.

The parties' briefs .and reply briefs generally tracked their respective witness's testimony. In its reply brief, MEC/NRDC/SC supported the Staff's position.

This PFD recommends that the Commission disallow $34.1 million for the Monroe dry fly ash processing project as recommended by the Staff and the Attorney General. As the Staff points out, DTE Electric management has provided only limited approval for benchmarking, legal due diligence, and conceptual design of the project, and the company's NPVRR was inadequate to demonstrate a net benefit to customers, given that the analysis did not contain all costs and all benefits. The Attorney General's disallowance of additional amounts, namely for the Monroe Fly Ash Dry Conversion and Monroe Inactive Impoundment Remediation projects are rejected. Mr. Paul's rebuttal

[31] 5 Tr 600.
[32] 5 Tr 599-600.

testimony is persuasive that these projects are reasonable and necessary, and they are unaffected by any reconsideration of the ELG rules. [33]

b. River Rouge Unit 3 (RR 3) Capital Expense

Mr. Paul testified that the net summer capacity of RR 3 is 272 megawatts (MW) and that DTE Electric is forecasting the retirement of that unit in May 2020.[34] Mr. Paul explained that because of environmental regulations that are expected to take effect in 2023, compliance costs for RR 3 and certain other coal-fired units would make these units uneconomical. In it retirement plans, in addition to economics, Mr. Paul testified that DTE Electric considers resource adequacy, the age of the generating unit, grid reliability, workforce planning, and community effects. [35]

Mr. Paul explained that as part of the retirement process, the company must file an Attachment Y Notification of Generator Change of Status form (Attachment Y notification) with MISO at least six months before a unit is retired. "In collaboration with the affected transmission owners, MISO will then perform a reliability study to determine whether the generation resource is necessary for the reliability of the transmission system[.]" Mr. Paul indicated that DTE Electric has filed the required Attachment Y notifications for RR 3, the St. Clair units, and Trenton Channel in anticipation of their retirements by 2023.[36]

Mr. Paul testified that DTE Electric has received the final study reports for RR 3

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[33] As Mr. Paul explained, the Monroe Inactive Impoundment Remediation project is required to be completed by October 2020 under the Coal Combustion Residual rule, and the Monroe Fly Ash Dry Conversion project is not subject to reconsideration and must be completed by the end of 2023. 4 Tr 598-599.

[34] 4 Tr 523.

[35] Id. at 524-526.

[36] 4 Tr 527-528. RR3, the St. Clair units and Trenton Channel are the company's so-called Tier 2 coal units, which, due to their ages and other factors, are expected to retire in the near future.

and the St. Clair units, stating that while none of the units has been designated a system support resource (SSR):[37]

> [T]he reports do indicate that retirement or suspension of these units may create thermal and voltage issues that could require the Company to shed firm load to ensure grid reliability. Although firm load shed is utilized as a countermeasure within MISO's planning criteria, the Company has significant concerns about implementing electrical service interruptions to our customers as a means of addressing known grid reliability issues. Maintaining and operating River Rouge and St. Clair power plants until their planned retirement dates will provide additional time to identify and implement alternative solutions that can ensure continued reliable electric service for its customers.[38]

Mr. Paul testified that in addition to potential reliability issues, the communities where the plants are located rely on property tax revenues from these plants, and a longer lead time to retirement will give these communities more time to prepare.

With respect to routine capital expenditures at RR 3, Mr. Paul testified that DTE Electric spent $5.4 million in 2017 and that it plans to spend $4.9 million in 2018 through April 2020. "These expenditures are mainly related to the replacement of pumps, motors, valves, instruments and control system components to maintain continued operations in a safe and environmentally compliant manner."[39]

Ms. Dimitry testified that, consistent with the Commission's order in Case No. U-18255, the company completed an updated NPVRR analysis of the retirement of RR 3. Ms. Dimitry explained that the analysis consisted of two options: operate RR 3 until its planned retirement in May 2020 or retire the unit as soon as practical in December 2018. Ms. Dimitry testified:

> For this evaluation, the Company assessed the incremental benefits and costs for both options, and calculated the net difference between the

[37] An SSR-designated unit must continue to operate to maintain system reliability.
[38] 4 Tr 528.
[39] 4 Tr 575.

> NPVRR of each option. A net positive difference indicates that the NPVRR associated with operating the RR Unit 3 through 2020 is more costly to customers; conversely, a net negative difference indicates that the NPVRR of operating the RR Unit 3 through 2020 is less costly to customers. It should be noted that the difference in retirement dates between the two options is only seventeen months.[40]

Ms. Dimitry explained that the results of the analysis, including sensitivity analyses for the capacity price input, showed a range of results "from $15 million more costly to $10 million less costly to customers to maintain the planned 2020 unit retirement date."[41]

Mr. Allison testified that using data provided by DTE Electric, he calculated that each of the company's Tier 2 units (RR 3, St, Clair, and Trenton Channel) demonstrated net losses, totaling $359 million, compared to the market from 2015-2017.[42] Mr. Allison also performed a sensitivity analysis using a replacement capacity price equal to 50% of MISO cost of new entry (CONE), reasoning that the highest of DTE Electric's recent short-term capacity purchases was 44% of CONE and the company also used 50% of CONE in its own analysis.[43] Mr. Allison explained that the results of his sensitivity analysis showed that even under the 50% of CONE capacity cost scenario, DTE Electric's Tier 2 units lost $160 million compared to the market,[44] adding that the company's Tier 1 units have also incurred operational losses of over $130 million from 2015-2017.[45]

With respect to RR 3 specifically, Mr. Allison testified that immediate retirement of the unit would save ratepayers $15 million comparted to continuing to operate the unit until May 2020, when the unit is scheduled to retire. Mr. Allison explained that:

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[40] 3 Tr 367-368; Exhibit A-12, Schedule B6.
[41] 3 Tr 369.
[42] 6 Tr 2596; Table 1.
[43] 6 Tr 2598; Exhibit A-12, Schedule B6, p.1.
[44] 6 Tr 2598-2599; Table 2.
[45] 6 Tr 2599; Table 3.

> [T]his net benefit estimate is understated, as DTE's analysis contains a clear error involving the under-valuation of energy generation under the 2018 retirement case. This error biases DTE's results in favor of continuing to operate River Rouge Unit 3. After correcting this error, I find that DTE's analysis indicates that continuing to operate River Rouge Unit 3 through 2020 will cost $21 million more than retiring the unit at the end of 2018.[46]

Mr. Allison disputed the validity of DTE Electric's NPVRR analysis, which showed a $15 million net benefit to early retirement under the company's PACE capacity price forecast, a $3 million net benefit to early retirement under a 50% CONE capacity price forecast, and a $10 net benefit to continuing to operate the plant under a 100% CONE capacity price forecast.[47] According to Mr. Allison, early retirement is likely to result in a positive economic benefit based on the range of results the company presented, noting that "[t]he absolute value of the greatest retirement benefit result ($15 million) is 50 percent greater than the absolute value of the greatest retirement loss result ($10 million)." Mr. Allison added that [t]he only way one might reasonably conclude that the NPVRR analysis results support the continued operation of River Rouge Unit 3 is if one believed that the 100% CONE capacity price sensitivity is the most likely scenario[.]"[48] Although Mr. Allison did not object to using the 100% CONE sensitivity analysis, DTE Electric "should have honestly presented it as an unlikely, worst-case scenario. Instead, DTE misleadingly presented the results of its high 100% CONE sensitivity alongside its PACE sensitivity, as if each sensitivity was equally likely."[49]

Contrary to Ms. Dimitry's and Mr. Paul's characterization of the PACE forecast as a low price forecast, Mr. Allison pointed to several proceedings where the company has

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[46] 6 Tr 2601
[47] Id. at 2602.
[48] 6 Tr 2603-2604.
[49] 6 Tr 2606.

used a PACE forecast as its base price scenario and not as a low price sensitivity. Consistent with its analysis in those proceedings, DTE Electric should have also presented a low price (lower than the PACE forecast) here. Mr. Allison also contended that the 100% CONE scenario represents an extreme situation in the MISO market, and DTE Electric did not provide any analysis to support the likelihood that such a price spike would occur. Referring to Mr. Fagan's testimony, Mr. Allison testified that MISO is likely to have significant excess capacity over the timeframe at issue here.[50] Mr. Allison added that even the 50% CONE forecast is unlikely, noting that all of DTE Electric's recent market purchases are at a lower price than 50% CONE.

Mr. Allison testified that DTE Electric's NPVRR analysis contained a significant error that makes the 2018 retirement of RR 3 look much less favorable. According to Mr. Allison:

> DTE's analysis mistakenly accounted for increased 2018 fuel costs under the 2018 retirement case without accounting for the increased energy revenues associated with those increased fuel costs. DTE's Exhibit A-12 indicates that the 2020 retirement case will result in $4 million lower fuel costs in 2018 than the 2018 retirement case. When asked about this discrepancy, DTE explained that the higher fuel costs under the 2018 retirement case are a result of "a two month (October and November) plant outage in the 2020 retirement scenario that will not occur in the 2018 retirement scenario." Upon reviewing DTE's NPVRR analysis workpapers, I found that they did in fact indicate greater electricity generation, and therefore greater fuel costs, in October 2018 and November 2018 under the 2018 retirement case compared to the 2020 retirement case. However, I also found that in another, further downstream part of the workpapers, DTE made the erroneous assumption that 2018 energy generation was the same under both retirement cases. This led DTE to erroneously calculate that there would be no difference in 2018 energy purchase costs or energy revenues between the two cases. In fact, the increased 2018 generation under the 2018 retirement case would clearly produce an economic benefit, either in the form of reduced energy purchases or increased energy sales. In essence, DTE's error amounts to assuming that under the 2018

[50] 6 Tr 2605-2606.

retirement case River Rouge Unit 3 burns $4 million worth of fuel without generating any energy.[51]

After correcting the error in the company's analysis, Mr. Allison found that the early retirement of RR 3 had an even greater economic benefit under both the PACE forecast and 50% CONE assumptions.[52]

Mr. Fagan testified that a review of MISO documents, including the 2018 OMS MISO resource adequacy survey, planning reserve auction (PRA) results for 2018/2019, and the MISO loss of load expectation (LOLE) planning report "illustrate that MISO on the whole, and Zone 7 also, continues to demonstrate near-term surplus resource availability and plentiful future resource options for utilities, as alternatives to reliance on relatively uneconomic and high-emitting coal plants."[53] Mr. Fagan noted that the 2018 OMS MISO survey indicates that the purported deficit in Zone 7 for 2019 did not account for import capability and the fact that load serving entities (LSEs) like Consumers and DTE Electric were still updating their plans.[54] Similarly,

> The [2019] LOLE report shows continuing downward pressure on local reliability requirements (LRR) for Zone 7, over the next ~6 years (the 2019 report contains LRR projections for Zone 7 for 2024/2025). The PRA results demonstrate considerable headroom remains available for imports into the Michigan load Zone 7, as only 320 MW of imports were seen at the auction.

Mr. Fagan summarized:

> The extent to which there will continue to be excess supply in MISO relies upon the fundamentals: projected load and resource balances across the region, accounting for the presence of new small-scale and utility-scale renewable and gas-fired resources, the effects of ongoing energy efficiency improvements across the region, the effects of transmission expansion to allow new resource interconnection, retirements of existing resources in MISO, and potential storage additions. Overall, there is no indication of

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[51] 6 Tr 2608-2609; Exhibits MEC-78 through MEC-80.
[52] 6 Tr 2810; Table 5.
[53] 6 Tr 2537.
[54] Id. at 2538.

> potential near or longer-term resource insufficiency in the broader MISO region. As aging and uneconomic coal plants retire, the need to meet capacity obligations will be met with demand-side resource reductions (the effect of increasing energy efficiency and available demand response resources), behind-the-meter resources (especially solar photovoltaic), and new wind, solar, storage, and to some extent gas-fired resources.[55]

In rebuttal, Ms. Dimitry testified that Mr. Allison failed to adequately consider resource adequacy issues, workforce planning, and community impacts in recommending that future capital and fixed O&M costs at RR 3 be disallowed.

Ms. Dimitry testified that it was not unreasonable to use the June PACE forecast as the low forecast, noting that Mr. Allison used the 50% CONE forecast in his analysis and that a November 2018 PACE forecast also showed market prices near 50% of CONE. Highlighting the significant difference between the June and November PACE forecasts, Ms. Dimitry disputed Mr. Allison's claim that 50% of CONE represents a high-price scenario.[56] Ms. Dimitry characterized the results of the NPVRR analyses as "mixed or marginal," and opined that in such circumstance, more attention should be paid to non-economic factors, citing Staff testimony in Case No. U-20165 as support.[57]

Mr. Paul echoed Ms. Dimitry's rebuttal, testifying that there were flaws in Mr. Allison's analysis and explaining that other factors, including resource adequacy and system and community impacts, should also be taken into account.

Mr. Arnold testified that in the MISO 2021/2022 planning year report, the local clearing requirement (LCR) for Zone 7 was increased due to an increase in the local reliability requirement (LRR) and a decrease in the capacity import limit (CIL), resulting in the need for more local (i.e,, located in Zone 7) resources in order to meet reliability

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[55] 6 Tr 2549; Exhibits MEC-40 and MEC-41.
[56] 3 Tr 374-375.
[57] Id. at 378.

standards. Mr. Arnold updated the Staff Report in Case No. U-18441 with the 2021/2022 numbers, resulting in a decrease in the LCR position from 1,220 MW to 264 MW. According to Mr. Arnold, "under this forecast MISO Zone 7 is 1% away from not meeting the LCR in 2021/2022."[58]

The parties' briefs and reply briefs generally relied on the testimony of their respective witnesses. DTE Electric emphasized changing forecasts that show that resource adequacy in Zone 7 is more constrained than MEC/NRDC/SC claim, based on updated information from MISO. In addition, the company reiterates that in addition to economic evaluation, other factors such as reliability and community impacts must be taken into account. MEC/NRDC/SC concur that other factors may play into a decision about when to retire a plant, but contend:

> [T]he question in this proceeding is not when particular generating units should retire. Instead, the Commission is faced with deciding who – DTE or its customers – should pay for the capital costs of generating units that the record shows are uneconomic and have been for a number of years. Second, DTE's evidence on these other factors ranges from virtually nonexistent to highly flawed and, therefore, the Company has failed to meet its burden of demonstrating that such other factors justify ignoring the clear evidence that River Rouge 3 and St. Clair units 1, 2, 3, and 6 are uneconomic.[59]

Issues concerning the economic efficiency of RR 3 (along with RR 2) first arose in Case No. U-17767, where MEC/NRDC/SC challenged the benefit of environmental retrofits of these units, in light of the high cost estimate of both the retrofits and the fuel sorbents necessary to operate the units. In discussing the issue, the Commission found:

> The ALJ presented a compelling analysis of this issue. The Commission agrees with the ALJ that customers should be protected from bearing costs for environmental retrofit projects at individual units in cases where such retrofits do not provide economic benefits. Based on the ALJ's analysis that

[58] 3 Tr 300-301.
[59] MEC/NRDC/SC's initial brief, p. 26.

> considered different sorbent cost estimates and other assumptions used by the parties, this is the concern for St. Clair units 6 and 7 and River Rouge units 2 and 3. That is, the ALJ found that the retrofit option is not cost effective for the units when the sorbent costs are within an expected range but above the levels referenced by the ALJ for purposes of setting her recommended cap. PFD, p. 64.[60]

Subsequently, in Case No. U-18014, the Commission agreed with the ALJ's recommendation to defer recovery of capital costs associated with RR 3, after RR 2 was retired:

> As was noted in the PFD, despite the fact that DTE Electric decided to permanently shut down River Rouge Unit 2, some months before the record in this proceeding opened, let alone closed, the company nevertheless failed to update its case to show the reduction in costs associated with Unit 2's retirement. Moreover, because many of the costs for Units 2 and 3 are shared, it was incumbent on DTE Electric to update its NPVRR to reflect the additional costs assigned to River Rouge Unit 3 along with updating other assumptions in the analysis.
>
> The Commission also rejects DTE Electric's contention that it cannot simply shut Unit 3 down without MISO's permission. As MEC/NRDC/SC points out,
>
>> The MISO discussion is a red herring, for several reasons. . . . That a utility analysis of the economics of a generating unit is a predicate to, rather than an end run around, the MISO approval process is shown by the fact that, as explained by Mr. Warren, the MISO process does not consider the economics to customers of the unit's continued operation versus retirement. Instead, MISO retirement approval considers potential impacts on grid reliability, including evaluation of mitigation measures. In other words, the MISO process pre-supposes that the utility has already undertaken an economic analysis of continued operation versus retirement of a generating unit. The MISO process does not prevent the utility from undertaking that analysis, nor dictate when to undertake that analysis.
>
> MEC/NRDC/SC's replies to exceptions, p. 11. . . . Finally, as the ALJ pointed out, all reasonable and prudent capital expenditures for River Rouge Unit 3 are, of course, recoverable in a future rate case.

[60] December 11, 2015 order in Case No. U-17767, p. 14.

Then, again, in DTE Electric's next rate case, the Commission deferred recovery of capital and O&M costs associated with RR 3:[61]

> The Commission adopts the recommendation of the ALJ. Despite having this cost category rejected in the 2017 order due to the failure to provide the NPVRR, and despite having been directed to file the NPVRR with future requests, DTE Electric chose not to include the analysis. Reasonable and prudent capital expenditures are recoverable, but not when the Commission is deprived of evidence upon which to base the determination that they are reasonable and prudent. The Commission sees no reason to deviate from the decision made in the last rate case.[62]

This PFD finds that the previously deferred capital costs, totaling $8.45 million, that were expended through December 31, 2018, were minimal, reasonably incurred, and should be recovered in rates in the instant proceeding. While issues about the economic operation of RR 3 were raised in the company's previous three rate cases, no specific retirement date for RR 3 was ever evaluated. Thus, MEC/NRDC/SC's recommendation to disallow these costs should be rejected. However, routine capital costs totaling $1.87 million for 2019 through the end of the test year are not reasonable and prudent and should be disallowed. O&M costs for 2019 and the test year should also be disallowed on grounds that the record in this case demonstrates that RR 3 could have, and should have, been retired at the end of 2018.

This recommendation is not an exercise in hindsight, nor is it an attempt to usurp management prerogative.[63] It has been over three years now since DTE Electric was first put on notice that the economics of operating the River Rouge units had been called into question. The issue became more pronounced in 2016, when RR 2 retired, leaving

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[61] Subsequently, the Commission granted the company's petition for rehearing and approved full recovery of O&M costs.
[62] April 18, 2018 order in Case No. U-18255, p. 8.
[63] DTE Electric is free to operate RR 3 as long as it would like, just not with ratepayer funding.

previously shared costs to be borne by RR 3 only. Because the company chose not to update its case and present a new NPVRR for RR 3 alone, the Commission deferred the company's proposed capital costs. Then in 2017, DTE Electric again failed to update its analysis of the continued operation of RR 3 and the Commission again deferred cost recovery.

Through the testimony of Mr. Allison and Mr. Fagan, MEC/NRDC/SC convincingly showed that the economics of operating RR 3 until the end of the test year is more likely than not to be detrimental to ratepayers and that there is significantly greater benefit to retiring the unit in December 2018. After correcting DTE Electric's error in its NPVRR analysis, and even using the 50% of CONE scenario, the net benefit of 2018 retirement is still $8 million, whereas under the 100% of CONE price forecast, the net benefit of a 2020 retirement date is only $5 million.[64] Although Mr. Arnold presented updates that show (at least until the next updates are issued) that capacity in MISO Zone 7 may be constrained in 2021/2022, this is long after RR 3 is planned to retire. Meanwhile, the forecasts for 2019 and 2020 do not appear to demonstrate any issues with available capacity in Zone 7.

DTE Electric points to other factors, including the possibility of thermal and voltage issues that need to be addressed for grid stability, as well as property tax considerations for the community where the plant will be closing, and workforce planning concerns, that should be considered in determining whether to retire the plant. This PFD agrees with DTE Electric that shedding firm load is not a reasonable option for dealing with grid stability, but the company has had <u>years</u> to devise a solution for this potential problem,

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[64] 6 Tr 2610.

and it failed to do so. The same is true for workforce planning concerns and mitigating the tax-related impacts of the plant closure in the City of River Rouge. For these reasons, this PFD recommends the disallowance of all capital costs for the first four months of 2019 and the test year as well as test year O&M costs.

c. <u>St. Clair Units 1, 2, 3, and 6 Capital Expense</u>

Through the testimony of Mr. Paul, Ms. Dimitry, and Mr. Arnold, DTE Electric supported capital costs associated with St. Clair Units 1, 2, 3, and 6. Recovery of these costs was disputed by Mr. Allison and Mr. Fagan on behalf of MEC/NRDC/SC, who argued that their analysis showed that continued operation of these units would be uneconomical, thus capital costs should be disallowed.[65]

In their brief, MEC/NRDC/SC contend that DTE Electric "attempt[s] to foreclose consideration of the economics of the Tier 2 units by noting that the Commission recently found in Case No. U-18419 that any plans to retire any of the Tier 2 units earlier than the Company has previously announced should await the outcome of DTE's upcoming 2019 [integrated resource plan] IRP analysis." MEC/NRDC/SC point out that DTE Electric made the same argument in Case No. U-18403, and the PFD, issued November 1, 2018, rejected that argument on grounds that the Commission did not determine that an IRP proceeding was the exclusive forum for addressing unit retirement, observing that, in the same order, the Commission stated that it intended to scrutinize costs in other proceedings, including rate cases, for prudency of costs that could have been avoided if more economical resources were available.[66]

[65] Presently, DTE Electric plans to retire the St. Clair units in 2022 and Trenton Channel in 2023.
[66] MEC/NRDC/SC's initial brief, p. 38.

In the April 27 order in Case No. U-18419, the Commission stated that it "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 Integrated Resource Plan (IRP) analysis and the results of MISO's Attachment Y reliability study." In addition, in the February 7, 2019 order in Case No. U-18403, the Commission found:

> [T]he Commission reiterates that it is not appropriate to relitigate values for capacity and other fixed and operating cost assumptions to assess whether the units are economic relative to historical and near term market prices. The Commission has repeatedly found that retirement decisions are best addressed through other proceedings and go beyond comparing the plant costs to MISO energy and capacity prices, recognizing the true value of capacity provided by the plants as well as real time reliability and societal considerations.[67]

Because DTE Electric is expected to file an IRP within a month, the issues raised by MEC/NRDC/SC concerning the economics of retiring the St. Clair units and Trenton Channel earlier than currently planned should be addressed as part of that proceeding, as the Commission has directed. These units are not currently expected to retire for three years or more, thus they are not similarly situated to RR 3. Accordingly, MEC/NRDC/SC's proposed disallowance of capital expenditures for the St. Clair units is rejected. Although this ALJ does not recommend deferral or disallowance of capital costs at this time, given that all aspects of the retirement of these units will be addressed in the IRP, the issue of cost recovery for these units should nevertheless be included in the company's next rate case, and the company should be directed to submit an up-to-date NPVRR for the St. Clair and Trenton Channel units.

[67] February 7, 2018 order in Case No. U-18403.

d. Combined Heat and Power Plant

Mr. Feldmann provided an overview of DTE Electric's proposed pilot CHP plant to be located at the Ford R&E campus, constructed and operated by DTE Power and Industrial (DTE P&I), and to be owned by DTE Electric and included in rate base. Mr. Feldmann explained that Ford was seeking to significantly update the existing infrastructure of the campus and therefore, "Ford initiated a plan to transform its Dearborn based R&E site into a flexible, smart, healthy, green, and engaging campus to address aging infrastructure and attract next generation talent to the State of Michigan."[68] Mr. Paul testified that:

> As part of that larger project, DTE Electric will develop a new 34 MW CHP plant to be located on Ford property. The CHP plant will provide electrical energy to serve Ford and other DTE Electric customers along with process steam to support the needs of the Ford Motor Company Research and Engineering Center complex. The project is expected to be completed by December 31, 2019 for $62.3 million.
>
> The CHP project consists of two 14.5 MW gas turbine generators and two heat recovery steam generators (HRSG). The steam produced by the HRSG's feed a common 5 MW condensing steam turbine generator and provides the process steam demands of the Ford Research and Engineering Center complex in Dearborn Michigan. Also included in the plant design are gas compressors, boiler feed pumps, deaerators, reverse osmosis water treatment systems, cooling towers, plant control systems and a myriad of other smaller components and system needs to operate a fully functional and independent electrical generating plant.[69]

Mr. Paul further testified that the CHP "will be highly flexible and capable of functioning at various output levels;" it will utilize "dry low-NOx combustors for NOx emissions reduction," and "[p]er the O&M agreement between DTE Electric (Owner) and DTE Energy Services (Operator), all major and day-to-day operations and maintenance

[68] 5 Tr 1129.
[69] 4 Tr 553-554; Exhibit A-12, Schedule B5.1, p. 2, line 32.

expenses will be borne by the Operator. Accordingly, there are no O&M expenses related to the Ford CHP project in this case."[70]

Mr. Feldmann testified that Ford undertook a request for proposal (RFP) process for the design, build, ownership, operation, and maintenance (DBOOM) of the central energy plant, including heating, cooling, and a CHP plant. Mr. Feldmann stated that "Ford requested that DTE provide a 'DTE Energy Corporate' (i.e., DTE Electric, DTE Power and Industrial, and DTE Gas) solution for the onsite central energy plant as part of the RFP process." Consistent with Ford's request, DTE Energy responded to the RFP and was awarded a 30-year contract to provide a CHP plant, chilled and hot water systems, energy storage, steam generation and distribution, and geothermal energy.[71]

Mr. Feldmann explained that because DTE Electric recognized that the purchase of the plant from DTE P&I was an affiliate transaction, and to ensure the cost of the CHP was reasonable and prudent, DTE contracted with HDR, "an architectural, engineering, and consulting firm, that developed an independent cost estimate for a 34 MW CHP plant at $84.6 million." Mr. Feldmann observed that "the transaction price is significantly below the estimated market price."[72] He added that DTE Electric would have entertained a similar offer from an unaffiliated third-party had such an offer been presented.

Mr. Feldmann listed the benefits of the proposed project including, among other things: (1) retaining Ford as a bundled customer with benefits of an estimated $102.1 million, on a net present value basis, over the 30-year life of the facility; (2) providing an

[70] 4 Tr 554-555. Mr. Paul did however note that O&M costs could be incurred for items that fall outside the scope of work for DTE P&I, including "control systems upgrades or variable frequency drive replacements more than two times during the life of the asset, changes in applicable law leading to increased Operator's costs, and modifications to the facility specifically required by the Owner." 4 Tr 555.
[71] 5 Tr 1129-1130.
[72] 5 Tr 1130; Exhibit A-28, Schedule R2.

opportunity for DTE Electric to learn from the pilot CHP project for future applications; (3) providing an additional, efficient generation resource to meet increasing demand; (4) improving the air quality in the area, once Ford retires the existing boilers; (5) providing black start services on site; and (6) allowing DTE Electric to retire an aging substation and underground cable at an estimated savings of $5 million. Mr. Feldman reiterated that if Ford were to contract with a third party for behind-the-meter generation:

> DTE Electric estimates that remaining bundled customers would have had to pay $102.1 million more on a present value basis over the 30-year contract life to make up for Ford's lost margin. . . .[T]he $102.1 million is comprised of the retained margin based on Ford's 2015 usage profile plus the margin associated with 62 million kWh of projected load growth in addition to the estimated replacement cost of the 63-year old substation and 16 miles of underground cable currently feeding the site.[73]

Mr. DeCooman noted that the cost of the proposed CHP plant was not the result of a competitive bidding process, and that the only proposal solicited by DTE Electric was from DTE P&I. Because the DTE P&I proposal was significantly (26%) less than the HDR estimate, DTE Electric did not seek additional proposals.[74]

Mr. DeCooman testified that, at the Staff's request, DTE Electric performed a levelized cost of energy (LCOE) analysis that confirmed that the cost of the CHP plant was competitive with alternative generating technologies.[75] Mr. DeCooman reiterated the key benefits of the project cited by Mr. Feldmann, noting that the retention of Ford as a bundled customer is by far the greatest. Mr. DeCooman concluded that:

> Based on Staff's audit of the information provided by the Company in the pre-filed direct testimony of Company witness Feldmann and responses to Staff's data requests, this project provides value to the ratepayers. This value is derived by both retaining the Company's largest customer as a

[73] 5 Tr 1133-1134.
[74] 8 Tr 4193.
[75] 8 Tr 4193-4194; Exhibit S-13.7, p.1. Confidential Exhibit S-13.8 incorporates steam sales to Ford in the LCOE calculation.

> bundled customer, while also providing energy at a comparable rate to other technology options. If the Commission does not find the Company's LCOE analysis adequate for the determination of reasonableness and prudence, Staff recommends the Commission order the Company engage in a competitive bidding process for the construction of the CHP plant.[76]

Mr. Coppola testified that DTE Electric's proposed purchase of the CHP plant from a company affiliate raises several concerns "and lacks transparency." Mr. Coppola pointed to several discovery responses that indicated that there was no competitive bidding for the proposed CHP plant, which in turn raise questions about the fairness of the purchase price.[77] Mr. Coppola disagreed with the company's reliance on the HDR report, contending:

> Such a desktop analysis and estimate is not the same, and is not a substitute, as receiving competitive bids from EPC contractors. The variance of $22.3 million between the $84.6 million cost estimated by HDR and the $62.3 million purchase price raises questions about the accuracy of the HDR estimate. The 26% variance would indicate that DTE P&I would be building a plant and selling it to DTEE at a large loss. This is a ludicrous proposition.[78]

Mr. Coppola testified that, overall, "there has been a lack of transparency as to how the purchase cost of $62.3 million was determined[,]" opining that, [i]f the Company had obtained alternative bids for the construction of the CHP plant along side with the construction bid from its affiliate, it would have been easily determinable whether or not the DTE P&I plant cost was fair and reasonable."[79] Mr. Coppola suggested that although it may be too late to request competitive bids it would nevertheless be helpful for the parties to be able to see and evaluate the actual construction costs of the plant. Mr.

[76] 8 Tr 4196.
[77] 5 Tr 1638.
[78] Id.
[79] 5 Tr 1639.

Coppola concluded that, in light of the limited information available, he could not support the inclusion of capital costs for the CHP plant in rate base, adding:

> The potential for cost subsidy between the utility and its non-utility affiliate is too great to ignore. It is likely that the Company and perhaps other jurisdictional electric utilities may use the same model of joining with non-utility affiliates on similar projects in the future. If the Commission grants approval for this project with no additional transparency, as I described above, and without requiring alternative competitive bids, it may set a bad precedent.[80]

On behalf of MEC, Mr. Sansoucy described the CHP plant project and its origin. He explained that DTE P&I is "is part of DTE Energy's non-utility operations that 'is comprised primarily of projects that deliver energy and utility-type products and services to industrial, commercial, and institutional customers, produce reduced emissions fuel, and sell electricity from renewable energy projects[.]'" and that DTE Gas, another company affiliate, albeit a regulated one, will construct a gas line to serve the CHP plant.[81]

Mr. Sansoucy testified regarding his concerns about the proposed transaction, observing that, "it is in the best interest of DTE Energy management and its shareholders that it controls as much of the work as possible at the highest profit margin possible. These interests are contrary to the interests of DTE Electric's ratepayers who are paying for the project through their rates and benefit from lower costs and efficient work."[82] Mr. Sancoucy explained that, in light of the fact that this is an affiliate transaction, heightened scrutiny by the Commission is necessary, not only of the CHP plant, but also the new gas line to be constructed by DTE Gas, the cost of the gas to be supplied to the CHP plant,

[80] Id.
[81] 6 Tr 2682; Exhibits MEC-107 and MEC-108.
[82] 6 Tr 2683.

and the benefits to DTE P&I, including investment or production tax credits, that should be shared with ratepayers.

Mr. Sansoucy took issue with DTE Electric's characterization of the CHP plant as a "pilot," noting that "[w]hile this 'pilot' may be unique for the Ford Motor Company, DTE Energy has been involved in many projects in Michigan and throughout the United States that have similar characteristics."[83] Mr. Sansoucy further explained that ratepayers should not have to bear the costs of a pilot, for which the benefits of education and experience accrue to DTE P&I. Mr. Sansoucy also raised specific concerns about the HDR estimate, observing that it is not clear whether the estimate is an "apples-to-apples" comparison, and noting that DTE Electric did not provide a cost breakdown from DTE P&I for the project.[84]

With respect to the HDR report specifically, Mr. Sansoucy testified:

> The indirect costs in HDR's estimate appear to be excessive. Based on Exhibit A-28, HDR has estimated the direct construction costs to be approximately $50.7 million. HDR estimated the construction indirect costs to total $12.5 million. HDR also estimated design and engineering management costs of almost $4.6 million, and EPC insurance and miscellaneous costs of another $2.7 million, for about $7.3 million of project indirect costs. HDR also included additional indirect costs of more than $14 million for EPC contingency and EPC general and administrative expenses. These costs, which total 27% of direct costs, are excessive in light of the $12.5 million already allocated to construction indirect costs. The total indirect costs, as projected by HDR, amount to approximately 67% of the direct costs.

Mr. Sansoucy added:

> HDR's estimate includes a section for the "Owners Costs". The costs include the natural gas pipe line, the transmission line 161kv, and the owner's 7.5% contingency. There are no values included in these line items, yet these are expenses that will be incurred in the development

[83] 6 Tr 2684; Exhibit MEC-110.
[84] 6 Tr 2686-2687.

> of this project. It is understandable that HDR would not include these costs in their estimate as it is not in their scope of work. However, these are legitimate costs that will ultimately be paid by DTE Electric and/or DTE Gas ratepayers in one way or another. Before considering ruling on the cost of one piece of the facility, the Commission should be provided with a clear estimate of the total cost that will be borne by DTE Electric and Gas customers for the CHP facility.[85]

Based on his evaluation of the proposed project, Mr. Sansoucy recommended that the Commission deny DTE Electric's request to include the project costs in rates because the company failed to provide sufficient evidence to demonstrate that the cost of the CHP plant was below the market price.

In rebuttal, Mr. Feldmann testified that a competitive bidding process for construction of the plant is no longer possible because DTE P&I began construction in March 2018. Mr. Feldmann also disputed Mr. Coppola's claim that the transaction lacked transparency pointing to the 600 pages of contracts "including all schematics, diagrams, agreements, exhibits, workpapers, and Excel spreadsheets that fully support and detail the deal structure between DTE Electric, Ford and DTE Power & Industrial."[86] Mr. Feldmann added that DTE Electric provided all supporting documents and spreadsheets used to develop the HDR report.[87]

Mr. Feldmann disagreed with the claims by Mr. Coppola and Mr. Sansoucy that the project should have been competitively bid, testifying:

> DTE Electric recognized this was an affiliate transaction, therefore, DTE engaged HDR, an architectural, engineering, and consulting firm, that has been in business since 1917, with over 100 years of experience, operating in all 50 states and 7 countries around the world, with over 10,000 employees to assist in developing an independent cost estimate for a 34 MW CHP plant. The Company retained HDR before receiving the P&I cost estimate. HDR's cost estimate at $84.6 million was significantly higher than

[85] 6 Tr 2687-2688.
[86] 5 Tr 1139; Confidential Exhibit A-40, Schedules DD1-DD7.
[87] 5 TR 1139; Confidential Exhibit A-40, Schedule DD8.

> the $62.3 million transaction price that DTE Electric negotiated. Further, both Witness Coppola and Witness Sansoucy fail to provide any comparative cost estimates, equipment costs, project development cost comparisons or benchmarking of similar facilities, they simply state that the price is too high because an affiliate is involved.[88]

In her initial brief, the Attorney General largely relies on Mr. Coppola's testimony, urging the Commission to deny recovery for the CHP plant. In its initial brief, MEC argues that the CHP plant should not be included in rate base for four reasons:

> First, in the request for proposals that DTE responded to, Ford sought to pay for and eventually own the CHP plant; and DTE Electric has not sufficiently demonstrated that having ratepayers pay for the plant is better than letting Ford pay for it. Second, DTE Electric did not competitively bid the construction of the plant, and has no valid justification for not doing so. Third, the HDR appraisal that DTE commissioned to justify not competitively bidding the plant is the same kind of self-serving report that the Commission has rejected in similar affiliate transaction cases.[89] Fourth, the HDR report contains numerous flaws and likely overstates costs.[90]

DTE Electric responds that Ford did not intend to own or operate the plant, pointing to the DBOOM RFP and the hundreds of pages of contracts provided in discovery. DTE Electric also disputes MEC's claims about the HDR Report, reiterating HDR's qualifications and experience. DTE Electric also maintains that the HDR Report, and the company's request here, can be distinguished from the circumstances in Case No. U-11636, because this situation involves an independent assessment by HDR, and not an appraisal that involved significant company input, as was the case in U-11636. Finally, DTE Electric maintains that the Attorney General and MEC failed to provide an alternative cost estimate, "[t]hey simply speculate that the price could be too high because an affiliate is involved."

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[88] 5 Tr 1140.
[89] November 16, 1999 Order in Case No. U-11636.
[90] MEC/NRDC/SC's initial brief (corrected), p. 71.

This PFD finds that DTE Electric's request to include the capital costs for the Ford CHP plant in rate base should be denied on grounds that DTE Electric failed to provide sufficient evidence to show that the purchase of the plant from an affiliate complies with the Code of Conduct.

Mich Admin Code, R 460.10108(4)[91] provides:

> If a utility provides services or products to any affiliate or other entity within the corporate structure, and the cost of the service or product is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8), compensation is based upon the higher of fully allocated embedded cost or fair market price. <u>If an affiliate or other entity within the corporate structure provides services or products to a utility, and the cost of the service or product is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8), compensation is at the lower of market price or 10% over fully allocated embedded cost</u>.

As stated above, the company must establish that the "compensation is at the lower of market price of 10% over fully allocated embedded cost." DTE Electric refers to the HDR Report as a "market price;" however, this PFD finds that the HDR report does not establish an independent market price. Indeed, it is this ALJ's view that the report is much more akin to a solitary bid than anything that could be remotely described as a definitive market price, which could have been established through an RFP for construction bids. In addition, the ALJ agrees with the Attorney General and MEC that the significantly higher estimated cost for the plant, as provided by HDR, raises questions about the validity of that estimate and whether the cost comparison between the DTE P&I proposal and the HDR Report is in fact, "apples-to-apples."

[91] On January 9, 2019, Mich Admin Code R 460.10101 *et seq.* was enacted, replacing the Code of Conduct that was approved in an order issued on October 29, 2001, in Case No. U-12134. Although there may be some question over which Code of Conduct applies, the provision cited above is nearly identical to Part III. C. of the previously effective code.

There does not appear to be much dispute that the cost of the CHP plant is reasonable compared to alternative generation based on the LCOE analysis, or that there are ratepayer benefits to retaining Ford as a customer.[92] But these issues are beside the point when confronted with the significant concerns raised by DTE Electric's failure to comply with the Code of Conduct. As the Attorney General points out:

> The potential for cost subsidy between the utility and its non-utility affiliate is too great to ignore. If the Commission grants approval for this project with no additional transparency and without requiring alternative competitive bids, it would set a bad precedent and it is likely that the Company, and perhaps other jurisdictional electric utilities, may use the same model of joining with non-utility affiliates on similar projects in the future, with no competitive process to protect customers from inflated prices.[93]

Accordingly, the $62.3 million purchase price for the CHP plant should be denied until such time as the company demonstrates that the cost of the plant is at or below market price, consistent with the requirements of the Code of Conduct.[94]

e. <u>Fuel Supply and Midwest Energy Resources Company Capital Expenditures</u>

Mr. Milo testified that the Midwest Energy Resources Company (MERC) is a subsidiary of the DTE Electric that provides coal transportation services to the company and other third-party customers. Mr. Milo explained that "[t]he accounting and ratemaking treatment of MERC's revenues and costs are specified by MPSC orders in Case No.

[92] Although the amount of these benefits is disputed.
[93] Attorney General's initial brief, p. 68.
[94] As DTE Electric points out, the opportunity to obtain competitive bids has passed because the CHP plant is currently under construction. Although competitive bidding is generally the preferred method to demonstrate compliance with the Code of Conduct's requirement to demonstrate a market price for comparison, the company could find some alternative means and present it in its next rate case.

U-5041, dated September 17, 1976, and Case No. U-5108, dated May 27, 1977.[95] The total capital expenditures of $5.66 million for 2017, $5.0 million for January 2018 through April 2019, and $2.9 million for the projected 12-month period ending April 30, 2020 relate to specific projects for safety, environmental requirements, and equipment upgrades, including a $2.3 million project to rebuild rail car trucks.[96] There were no adjustments offered by any of the parties. Accordingly, fuel supply and MERC capital expense should be approved as proposed by the company.[97]

3. Nuclear Capital Expenditures

Mr. Davis testified in support of nuclear production capital expenditures and O&M expense during the historical, bridge, and test periods for the Fermi 2 nuclear plant. Mr. Davis also testified regarding the reasonableness and prudence of the nuclear surcharge, the nuclear component of the IRM, as well as the company's AFUDC forecast.

Mr. Davis explained that total capital expenditures for nuclear generation are comprised of: (1) routine and small projects; (2) non-routine and large projects; and (3) total nuclear fuel. Mr. Davis indicated that capital expenditures for the historical period test period totaled $161.2 million, forecast expenditures for the interim period total $284.3 million, and projected capital expenditures for the test year are $253.5 million.[98] Mr. Davis

[95] 6 Tr 2288.
[96] 6 Tr 2289-2291; Exhibit A-12, Schedule B5.2.
[97] The RCG cross-examined Mr. Milo about the necessity of rail car truck rebuild but did not propose a disallowance. The Attorney General's recommended adjustment to fuel supply inventory is discussed below under working capital.
[98] 5 Tr 1270-1271; Exhibit A-12, Schedule B5.3, p.1, line 10. Exhibit A-12, Schedule B5.3, pp. 2-3 provides expenditure detail on routine and small capital projects. In the same exhibit and schedule, page 4 provides detail on non-routine and large projects. Mr. Davis testified that none of the routine and non-routine projects contain contingency. DTE Electric's AFUDC forecast can be found on page 5 of Exhibit A-12, Schedule B5.3.

explained that due to the company's concern for nuclear safety, most capital projects are implemented during planned outages, one of which will occur in fall 2018, with a second scheduled for spring of 2020.[99] Mr. Davis added that the $52.9 million increase from the historical to the test period in non-routine and large project capital expenditures is largely attributable to the replacement of the Fermi 2 main unit generator.[100]

Mr. Davis testified that nuclear fuel includes capital expenditures for uranium, conversion, enrichment, and fabrication. Mr. Davis explained that these expenses, which range from $0.4 million in the historical year to $77.7 million in the projected test year, vary substantially and in accordance with the 18-month refueling cycle.[101] Finally, Mr. Davis testified that the historical AFUDC for nuclear was $5.7 million and the projected amount is $7.4 million.[102]

The amounts that DTE Electric proposed for nuclear capital expenditures and AFUDC (nuclear) for the test year were not contested and should therefore be approved.

4. Distribution Capital Expenditures

DTE Electric proposed distribution operations capital expenditures of $651.4 million in the 2017 historic year, $810.2 million for 2018, $285.6 million for the four months ending April 30, 2019, and $830.6 million for the projected test period.

Mr. Bruzzano testified that DTE Electric's Distribution Operations is comprised of seven units including service operations, substation operations, system operations, emergency preparedness and response, tree trimming, operational technology, electrical

[99] 5 Tr 1273. Mr. Davis noted that after a planned outage in fall of 2021, Fermi 2 will move to a 24-month outage cycle.
[100] 5 Tr 1276-1277.
[101] 5 Tr 1280-1281.
[102] 5 Tr 1281; Exhibit A-12, Schedule B5.3, p. 5.

engineering & planning, and scheduling & coordination.[103] Mr. Bruzzano continued, describing in some detail DTE Electric's electrical system, including system size, locations of key infrastructure, and average age of different assets.[104] Mr. Bruzzano also provided extensive testimony on the company's proposed investments for the bridge and test periods, including specific project scope, timeline, costs and benefits, and performance metrics.

Mr. Bruzzano testified that the company measures system reliability using the system average interruption duration index (SAIDI) which is "defined . . . as the total time (in minutes) of all customer interruptions divided by the total number of customers served." Mr. Bruzzano added that SAIDI is measured in two ways: "(1) All-Weather SAIDI, which includes all outages, and (2) SAIDI-Excluding Major Event Days (MEDs), which excludes days with outages that exceed a size threshold to isolate the impact of the most severe weather events."[105] Mr. Bruzzano presented charts showing the all-weather SAIDI and SAIDI excluding MEDs which demonstrate that DTE Electric is in the bottom quartile from 2012-2016 for SAIDI excluding MEDs.[106] Mr. Bruzzano also pointed to DTE Electric's five-year plan, ordered in Case No. U-18014, as justification for the company's planned spending in distribution operations.

In supporting DTE Electric's proposed distribution capital expense, Mr. Bruzzano summarized:

> DTE Electric's distribution system is aging and, in many cases, is operating well beyond typical design life. A combination of increasing equipment failure rates, growth in economic activity, and redevelopment in the region will require higher capital expenditures to connect customers

[103] 4 Tr 697-698.
[104] 4 Tr 698-701.
[105] 4 Tr 702.
[106] Id. 703.

> and to upgrade electric infrastructure in a way that reduces risk, improves reliability, and helps manage costs. Investments in technology are needed to improve preparedness for catastrophic events and provide better response time during outages, but also to support the evolving way in which customers will use the grid, as distributed resources continue to grow.[107]

There were several adjustments to DTE Electric's proposed distribution capital expenditures, as well as debate concerning certain reporting recommendations, that are discussed below.

a. <u>DTE Electric's Five-Year Plan</u>[108]

In Case No. U-18014, the Commission directed DTE Electric to develop a five-year distribution plan as follows:

> The plan should comprise: (1) a detailed description, with supporting data, on distribution system conditions, including age of equipment, useful life, ratings, loadings, and other characteristics; (2) system goals and related reliability metrics; (3) local system load forecasts; (4) maintenance and upgrade plans for projects and project categories including drivers, timing, cost estimates, work scope, prioritization and sequencing with other upgrades, analysis of alternatives (including AMI and other emerging technologies), and an explanation of how they will address goals and metrics; and (5) benefit/cost analyses considering both capital and O&M costs and benefits.
>
> A plan of this nature would increase visibility into the system needs and facilitate review by the Staff, other parties, and the Commission outside the contested rate case process. The Commission does not expect to formally "approve" the plan, but sees value in having a more thorough understanding of anticipated needs, priorities, and spending. The Commission therefore directs the Staff to work with the company to address clarifying questions on the plan framework and to develop an appropriate timeline for submittal and review. The Commission further directs DTE Electric to submit a draft plan to the Staff by July 1, 2017, and meet with the Staff to complete a final five-year distribution investment and maintenance plan to be submitted by December 31, 2017.[109]

[107] 4 Tr 812.
[108] Exhibit A-23, Schedule M5.
[109] January 31, 2017 order in Case No. U-18014, pp. 40-41.

In a subsequent order, issued after notice and an opportunity to comment on DTE Electric's draft plan, the Commission provided some additional clarification and guidance, including: (1) five-year plans should have safety as a central focus; (2) resiliency and reliability must also be addressed in the plans; (3) the plan must provide for improvements that are cost-effective and affordable for ratepayers; and (4) the plan must provide for an accessible grid that will accommodate new technologies, new customers or changing loads.[110] The Commission therefore directed DTE Electric to primarily focus on:

> 1. Defining the scope of work, capital, and O&M investments needed to address aging infrastructure and the risk assessments that drive the prioritization of these investments (i.e., asset class failure rates, long lead time equipment, obsolete equipment, etc.).
>
> 2. Identifying known safety concerns on the system and work necessary to address these concerns (i.e., pole failures, third-party facilities coming into contact with electric equipment, and wire down detection, response, and protections, etc.).
>
> 3. System maintenance and investment strategies that improve resiliency and mitigate the financial effects and safety issues associated with inclement weather (i.e., strategic undergrounding, accelerated vegetation management schedules, enhanced vegetation management standards, tree resistant conductors, etc.).
>
> 4. Company objectives and associated performance metrics relevant to utility near-term investment and maintenance plans. In particular, the Commission expects a timeline and investment strategy for meeting the Governor's 2013 reliability goals addressing the frequency and duration of electric outages.[111]

The Commission also made clear that the principal focus of the plan in the near-term was customer safety and system reliability, whereas subsequent plans should include "leveraging new resources and approaches, such as energy efficiency, renewable energy, storage, line loss, volt/volt-amphere [sic] reactive optimization, NWAs, and

[110] October 11, 2017 order in Case Nos. U-17990 and U-18014, pp. 10-12.
[111] Id. at 15-16.

dynamic electric rate structures, to address looming system issues."[112] Finally, the Commission directed the Staff, after submission of final distribution plans, to convene a stakeholder group to develop a "framework for the development of future distribution plans and to report back its findings to the Commission no later than September 1, 2018[,]" adding that "the Commission . . . expects the companies' distribution plans to provide program costs and benefits to ensure the cost effectiveness and affordability of their distribution plans."[113]

While this PFD agrees that distribution spending projections in this proceeding should generally align with the priorities defined by the Commission, and included in the five-year distribution plan, the Commission has nevertheless made clear that the purpose of the plan is to provide more "visibility" into system needs, and not necessarily to justify increased spending. The Commission also made "ensur[ing] cost effectiveness and affordability" a focus of the plans. Thus, to the extent that the five-year plan provides "visibility" it has value, but at this point, using (let alone approving) the Five-year plan for the purpose of cost recovery is not reasonable. The Commission so indicated in its November 21, 2018 order in Case No. U-20147:

> The Commission agrees with the Staff that Consumers' and DTE Electric's next set of plans should be filed in 2020, specifically no later than June 30, 2020. Although these updates to their distribution plans will not then be filed directly alongside their IRPs, an alignment with potential long-term value, *these next iterations will nevertheless follow on the heels of a Commission order addressing Consumers' IRP and then the filing of DTE Electric's IRP application, along with Commission orders addressing the companies' current pending rate cases (Case Nos. U-20134 and U-20162), all being matters which should bring about meaningful, effective, and actionable items within Consumers' and DTE Electric's next iterations of their distribution plans*. As these processes evolve, the Commission

[112] Id. at 17.
[113] Id. at 18.

envisions improved alignment of resource, transmission, and distribution planning in terms of timing, assumptions, and alternative analyses.[114]

Thus, it appears that the Commission, at least to some degree, envisions the proposals presented in this case to inform the next iteration of the five-year plan, and not necessarily the other way around.

b. *Staff's Adjustments*

i. 2017 Historical Spending

In his direct testimony, Mr. Evans explained that he examined DTE Electric's historical spending on distribution programs generally and determined that the amount the company spent in 2017 was 15.7%, or $88.3 million,[115] more than was authorized in the company's last rate case, Case No. U-18255.[116] Mr. Evans testified that to identify the programs in which overspending occurred, he adjusted the company's distribution spending proposed in Case No. U-18255 for the amounts approved in the Commission's final order. Then he compared these amounts to the amounts in Exhibit A-12, Schedule B5.4. Mr. Evans noted that while some projects or programs carried over from the previous rate case to this one, other programs could not be readily identified, thus a comprehensive comparison could not be performed. Nevertheless, Mr. Evans was able to perform "a limited crosswalk" between the previously approved spending and the actual approved spending that showed that "Emergent Retirement Unit Changeouts and Storm," (which translated to "Storm and Non-Storm in this case) had the most significant overspending.[117]

[114] November 21, 2018 order in Case No. U-20147, pp. 36-37 (fn omitted).
[115] 8 Tr 4102; Exhibits S-10.1 and S-10.2.
[116] 8 Tr 4101, referencing Exhibit A-12, Schedule B5.4 pages 1-10.
[117] 8 Tr 4105-4106.

While initially recommending a disallowance of this cost, the Staff subsequently determined that the $88.3 million overspending was supported through the company's rebuttal testimony on the major storm that occurred in March 2017.

In its initial brief, the Staff recommended that in the future, if the company has significant overspending in a particular category of expenses, the company should notify the Staff near the time the overspending occurs. In its reply brief, DTE Electric indicates that it does not disagree with this recommendation, to the extent that it does not impose any new legal requirements on the company.

Although not raised by the Staff in testimony or in its briefs, this PFD finds it concerning that the Staff and intervenors were required to first create a "crosswalk" between spending categories from the company's previous rate case, before beginning to evaluate the company's proposals in this proceeding. The company is, of course, free to reclassify or rename different spending categories and subcategories; however, given the very tight timeframes required for rate case processing since 2017, it should be incumbent on the company, and not the other parties, to explain how spending classifications in a previous case translate into the current case. The Commission should consider revising the rate case filing requirements accordingly.

ii. 2018 Adjustments

Mr. Evans recommended a disallowance of $64,455,000 for 2018 distribution capital expense based on his evaluation of DTE Electric's spending amounts in different categories and subcategories in the first eight months of the year. In order to analyze DTE Electric's spending, Mr. Evans extrapolated amounts for the last four months of 2018 spending on the basis of spending to date:

> The extrapolated spending is calculated by dividing $135,843,000 by 8 months and then multiplying the result by 12. (This is mathematically equivalent to multiplying by 1.5, and will be referred to as such throughout the remainder of my testimony.) This yields predicted spending of $203,764,500, which is very close to the official projected spending of $201,921,000.

Using this method, Mr. Evans testified that the Customer Connections, Relocations and Other subcategory of the Strategic Capital category (calculated in the quoted testimony above) was on track to spend the projected amount, and therefore no adjustment was warranted.[118]

For the Infrastructure Resilience and Hardening, subcategory, Mr. Evans calculated a shortfall of $36,728,000 in his extrapolation, for which he proposed a disallowance. Similarly, for Infrastructure Redesign, Mr. Evans found a difference of $66,031,000, and for Technology and Automation, the difference in actual to projected spending was $54,362,000. Mr. Evans testified that these Strategic Capital subcategories would likely be underspent by the end of 2018, noting that in some cases, the ability to undertake projects is outside the company's control and in other cases, there is simply not time left in the year to assume significant additional spending.[119]

In addition to the above disallowances, Mr. Evans recommended that the Drexel Station project amounts be disallowed because DTE Electric failed to include this substation in its Substation Risk Model.[120]

Mr. Evans testified that the amounts proposed for disallowance were offset by upward adjustments in the Emergent Replacements category, which was significantly overspent in the first eight months of 2018. Mr. Evans calculated that, "[i]n total, the

[118] 8 Tr 4110.
[119] 8 Tr 4111-4112; Exhibit S-10.4.
[120] 8 Tr 4113.

Company spent $232,043,000 from January 2018 – August 2018 compared to a $202,104,000 projection for calendar year 2018."[121] To calculate the additional amount of spending for the remainder of 2018, Mr. Evans explained:

> Staff utilized a methodology that assumed the accelerated pace of spending would continue for the rest of the year in two of the three Emergent Replacements sub-categories and stop completely in the third. To lower the risk of overestimating, Staff chose the two sub-categories with the lower YTD Actual spending, Non-Storm and Substation Reactive, as the sub-categories to adjust upward. Storm, the sub-category with the highest YTD Actual spending, was determined to be the sub-category where spending stops.
>
> For the Non-Storm sub-category, Staff extrapolated the YTD Actual spending of $99,970,000 to 12 months to arrive at annual spending of $149,955,000. Subtracting the two amounts yields an upward adjustment of $49,985,000. For the Substation Reactive sub-category, Staff extrapolated the YTD actual spending of $30,020,000 to 12 months to arrive at annual spending of $45,030,000. Subtracting the two amounts yields an upward adjustment of $15,010,000. For the Storm sub-category, Staff did not add any additional expenditures. Staff is also not proposing any adjustment to the Emergent Replacement Reduction Based on Strategic Spend sub-category, as zero was recorded for YTD actual for January 1, 2018 – August 31, 2018 in Exhibit S-10.4, page 6, line 6, column (b). Adding the two upward adjustments together yields an upward adjustment to the Emergent Replacements category in the amount of $64,995,000, which is an estimate of how much the Company could spend in the Emergent Replacements category from September 1, 2018 – December 31, 2018.[122]

Mr. Evans added that the lack of an adjustment to the Storm subcategory is not intended to limit the company's storm replacement efforts if additional capital is needed, noting, "Staff is adjusting the Emergent Replacements category upward as a whole, and Staff's methodology should provide the Company enough funding to meet the various demands of the Storm, Non-Storm and Substation Reactive sub-categories."[123] In total, the Staff's net disallowance as filed was as follows:

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[121] Id. at 4114.
[122] 8 Tr 4115.
[123] Id. at 4116.

Infrastructure Resilience and Hardening =	-$36,728,000
Infrastructure Redesign =	-$66,031,000
Technology and Automation =	-$54,362,000
Substation Risk: Drexel =	-$2,268,000
Emergent Replacements Jan – Aug 2018 =	+$29,939,000
Emergent Replacements Sept – Dec 2018 =	+$64,995,000
Total Adjustment =	**-$64,455,000**[124]

In its initial brief, on the basis of Mr. Bruzzano's rebuttal testimony, which updated the company's spending in the different distribution operations subcategories,[125] the Staff reduced its initial proposed disallowance of $64,455,000 to $19,223,000:

> Staff's new $19,223,000 disallowance is the result of using updated 2018 spending numbers for the Strategic Capital sub-categories and the Connections & Other category, eliminating the Substation Risk: Drexel disallowance, keeping the Emergent Replacements January – August 2018 overspend, increasing the Emergent Replacements September – December 2018 upward adjustment, and including the negative spending on miscellaneous items.[126]

The Staff explained that it agreed with all of DTE Electric's updated projections for 2018, except for Emergent Replacements, for which the company calculated $356,844,000 for the year, based on a straight-line extrapolation of $297,370,000 of actual spending through October 2018. According to the Staff, "[t]his amount is simply too high and assumes that the higher-than-forecasted spending in Emergent Replacements will continue in November and December."[127] The Staff noted past volatility in annual Emergent Replacements spending and argued that such volatility could also be found looking at monthly spend. Thus, the Staff recommended that the company's prefiled projections of spending on Emergent Replacements, of $16,842,000 for each month be adopted.

[124] Id. at 4117.
[125] See Exhibit A-31, Schedule U-7.
[126] Staff's initial brief, p. 41; Exhibit A-31, Schedule U-7.
[127] Staff's initial brief, p. 40.

In its reply brief, DTE Electric contends that the Staff's method for calculating 2018 year-end spending is flawed. DTE Electric takes specific issue with the Staff's assumption that there will be no additional spending in the Emergent Replacements category, noting that storms can and do occur in November and December. The company also objects to the Staff's contention that the 2018 projected spending on Emergent Replacements is simply "too high," contending that the Staff's characterization was arbitrary.[128]

This PFD finds that the Staff's 2018 projection for distribution operations capital expense is reasonable and that the proposed $19,223,000 disallowance, out of a projected spending amount of near $800 million for 2018, is likewise reasonable. It should be noted that the Staff modified its case using the company's updates to 2018 capital expense, even though these revised amounts, which included an additional two months of spending, were not audited and, as such, should be viewed with some reservation. The ALJ finds that the Staff's determination that the Emergent Replacements spending for 2018 was "too high" and should be adjusted was not arbitrary. DTE Electric admitted that storm activity in early 2018 was higher than usual, and Mr. Evans explained how the adjustment was made. In addition, the Staff made clear that, overall, there were sufficient funds available to cover distribution operations costs for the remainder of 2018.

iii. January- April 2019 and Test Year Distribution Operations

DTE Electric projected $285,557,000 in distribution operations for the first four months of 2019, including $67,933,000 for Emergent Replacements; $71,845,000 for Connections & Other; and $145,779,000 for Strategic Capital. For the test year, the

[128] DTE Electric's reply brief, pp. 30-31.

company projected $830,578,000, including $204,580,000 for Emergent Replacements; $193,059,000 for Connections & Other; and $432,939,000 for Strategic Capital.[129]

Mr. Evans testified that the Staff proposed a downward adjustment of $31,447,000 for distribution capital expense for the four months ending April 30, 2019, based on the fact that Strategic Capital spending was below projections for 2018, opining that it is reasonable to assume this trend will continue. However, based on the Staff's review of DTE Electric's Five-year distribution plan, Mr. Evans testified that the Staff projected the shortfall in this category to be less than what occurred in 2018.[130] Mr. Evans added that it is likely that Emergent Replacements spending would be near the amount the company projected, and that spending on Connections and Other would also be similar to the company's projection.

Mr. Evans testified that the Staff's projection of overall distribution capital expense for 2019 was $762,331,000, based on its projected 2018 expense amount plus 2.23% for 2019 inflation. "Inflating the 2019 amount by Staff's 2020 inflation rate of 2.50% but only including four months of spending provides $260,463,000 for the first four months of 2020. Staff adopts these amounts for total distribution capex for January 1, 2019 – April 30, 2020."[131] The proposed $31,447,000 reduction was calculated by using the $762,331,000 projection number for 2019 and dividing it by three to obtain four months of distribution capital expense for 2019, which equals $254,110,000. Subtracting this amount from the company's projection of $285,557,000 for January-April 2019, equals $31,447,000.[132]

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[129] Exhibit A-12, Schedule B5.4.
[130] 8 Tr 4118.
[131] Id. at 4119.
[132] 8 Tr 4119; Exhibit S-10.0, line 22, column (g).

Mr. Evans explained the method the Staff used for determining Strategic Capital spending for January-April 2019:

> I first took Staff's forecasted distribution capex amount for the first four months of 2019, $254,110,000, and from it subtracted the $67,933,000 for the Emergent Replacements category and the $71,845,000 for the Connections & Other category. This left $114,332,000. . . . Since Staff has calculated an amount for the Strategic Capital category that is 78.4% of the Company's projection, Staff conservatively estimates that the emergent replacement reduction will be about 75% of the Company's projection. Therefore, Staff lowered the $2,827,000 reduction to $2,120,000, a decrease of $707,000. This changes Staff's projection for the Emergent Replacement category to $68,640,000, and Staff considers this amount to be reasonable and prudent.
>
> Since Staff had already adopted total distribution capex amounts, those expenditures must come from another distribution capex category. Staff decided to adjust its calculated Strategic Capital category amount downward by $707,000, which results in a final Staff projection of $113,625,000, or 77.9% of the Company's projection. Staff finds this amount to be reasonable and prudent. Staff chose to adjust the Strategic Capital category downward because expenditures from this category were used to fund work in the Emergent Replacements category in 2018.[133]

For the test year, Mr. Evans calculated a downward adjustment of $61,894,000. Using the 2019 amount of $762,331,000,

> Staff simply took two thirds of this amount to obtain a reasonable and 16 prudent spending amount for May 1, 2019 – December 31, 2019, which turned out to be $508,221,000. Next, Staff took the $260,463,000 calculated for the first four months of 2020, and then added this number to the May 1, 2019 – December 31, 2019 amount to obtain $768,684,000. Staff then subtracted this number from the Company's projected $830,578,000 to arrive at the test year disallowance of $61,894,000.[134]

Mr. Evans testified that the Staff found the company's projections for Emergent Replacements and Connections and Other to be reasonable, and applied the same

[133] 8 Tr 4120-4121.
[134] Id. at 4121.

method described above to determining the amounts projected for distribution capital expense:

> Staff believes the Company will spend at least $790,934,000 for distribution capital expenditures in 2019, which is the same amount as Staff's projection for 2018. (Exhibit A-44.) Inflating this 2019 amount by Staff's 2020 inflation rate of 2.50% but only including four months of spending provides $270,236,000 for the first four months of 2020. Staff adopts these amounts for total distribution capital expenditures for January 1, 2019 – April 30, 2020. The $21,912,000 disallowance for the first four months of 2019 is the difference between the Company's projection of $285,557,000 and Staff's projection of $263,645,000, which is Staff's 2019 distribution capital expenditures of $790,934,000 pro-rated for four months (divided by three). The $33,053,000 test year disallowance is the difference between the Company's projection of $830,578,000 and Staff's test year projection of $797,525,000. Staff's test year projection was calculated by adding eight months of Staff's 2019 projection ($527,289,000) to Staff's projection for the first four months of 2020 ($270,236,000).
>
> For the first four months of 2019, the Company is projecting $67,933,000 for Emergent Replacements and $71,845,000 for Connections & Other. (Exhibit A-12, Schedule B5.4.) Staff finds these amounts reasonable. Using Staff's projected distribution capex for the first four months of 2019, ($263,645,000), leaves $123,867,000 for Strategic Capital. Since the Company is projecting $145,779,000 for Strategic Capital during this period, the Staff is recommending for the first four months of 2019 that the Company recover 85% of its projection for this category.
>
> For the test year, the Company is projecting $204,580,000 for Emergent Replacements and $193,059,000 for Connections & Other. (Exhibit A-12, Schedule B5.4.) Staff finds these amounts reasonable. Using Staff's projected distribution capex for the test year, ($797,525,000), leaves $399,886,000 for Strategic Capital. Since the Company is projecting $432,939,000 for Strategic Capital during this period, Staff is recommending for the test year that the Company recover 92.4% of its projection for this category. [135]

In its initial brief, the Staff refined its recommendation to include the 2018 updates provided in Mr. Bruzzano's rebuttal. This resulted in a reduced disallowance of $21,912,000 for the first four months of 2019 and a lower $33,053,000 disallowance for

[135] Staff's initial brief, pp. 43-44.

the test year.

DTE Electric maintains that the Staff's adjustments for the bridge and test periods are not warranted or supported. DTE Electric argues that because the disallowances were based on the Staff's flawed calculation of 2018 distribution spending, these adjustments should be rejected. In addition, DTE Electric contends that the Staff failed to recognize additional spending supported by the company's Five-year plan and instead used an "historical plus inflation" method to project spending. DTE Electric adds:

> Staff initially used, and continues to use, an arbitrary and unreasonable approach to test whether its projection of Strategic Capital is reasonable and prudent (4T 850, 852-53). Staff reasons that the Company was "on track" for 63.7% spending in 2018, and that a reasonable "middle ground" (between 63.7% and 100%) would be 81.9%, so Staff's projections are reasonable because they are greater than 63.7% (Staff Initial Brief, p 44-45). This type of tautological reasoning does not actually lend anything to the debate as it is based not upon facts and system needs, but rather, on numbers chosen seemingly at random. [136]

DTE Electric argues that the Staff's reliance on 2018 part-year spending on Strategic Capital projects should be rejected because, as Mr. Bruzzano explained, the company's investments were constrained by significant storm activity earlier in the year and that the company plans to spend 100% of its proposed amounts in 2019 and 2020.

Finally, DTE Electric points out:

> [E]ven assuming for argument's sake that Staff's proposed disallowances merit consideration, they should be supported and consistent. Staff initially made its spending calculations using inflation of 2.23% for 2019 and 2.5% for 2020 (8T 4118-19). Staff now offers projections that inconsistently and without support exclude inflationin 2019, but include it in 2020.This appears to be an oversight, as Staff provides no explanation or rationale for excluding interest in 2019 then restoring it in 2020 (Staff Initial Brief, pp 41, 43).Staff's resulting proposed disallowances are $21,912,000 for the first four months of 2019, and $33,053,000 for the test year. If Staff had applied inflation consistently as it indicated initially, then

[136]DTE Electric's reply brief, pp. 32-33.

> its proposed disallowances would be $16,033,000 for the first four months of 2019, and $15,268,000 for the test year. Therefore, even if Staff's proposed methodology were to be followed (which it should not be), Staff's proposed disallowances are overstated by $5,879,000 for the first four months of 2019 ($21,912,000 -$16,033,000), and $17,785,000 for the test year ($33,053,000 -$15,268,000).[137]

Except for the company's adjustment to include 2019 inflation, which is appropriate, this PFD finds that the Staff's projections for distribution operations capital expense for the bridge period and test year are reasonable. As discussed above, the Staff's 2018 projection was reasonable, although based in part on two additional months of unaudited spending presented in rebuttal. This PFD further finds that the Staff did in fact recognize that the company will ramp up spending in the test year on Strategic Capital programs and made modifications accordingly, assuming that the company will spend 85% of Strategic Capital in the first four month of 2019, and 92.4% in the test year. Accordingly, this PFD adopts the Staff's recommended disallowances, adjusted for 2019 inflation, as calculated in DTE Electric's reply brief.

c. *Attorney General's Adjustments*

i. New Business

Mr. Coppola testified that for the first four months of 2018, DTE Electric projected spending of $27,272,000 for new business, but in fact spent 36%, or $9.8 million, less than the projected amount. Mr. Coppola testified that "giving the Company the benefit of the doubt that capital expenditures in the remaining four months will meet the forecasted level, it is reasonable to conclude that the cumulative under-spent amount of $9,792,000 for the 8 months ended August 2018 is likely to remain."[138] Consistent with his testimony,

[137] DTE Electric's reply brief, pp. 33-34.
[138] 5 Tr 1627; Exhibit AG-13.

the Attorney General recommended that DTE Electric's 2018 capital expense be reduced by $9,792,000.

Mr. Coppola also raised issues with respect to DTE Electric's projected spending on New Business for the first four months of 2019 and the test year. Mr. Coppola explained that in discovery, he requested the number of New Business contracts that had been signed for 2019 (six) and 2020 (none). Mr. Coppola opined that based on that response, "the Company simply included a 'ballpark' estimate of potential future projects to be completed in 2019 and 2020 as placeholders for future expenditures."[139]

In rebuttal, Mr. Bruzzano pointed out that the Attorney General's own exhibit showed that while the New Business subcategory was underspent, the 2018 Connections and New Load category in its entirety was overspent by over $1 million by August of that year. Mr. Bruzzano explained that this reflected "the continued strong economic growth in the Company's service territory."[140]

Mr. Bruzzano also disputed Mr. Coppola's projected New Business expense for 2019 and the test period, pointing out:

> New Business Projects have experienced 37% compounded annual growth over the past five years (2013-2017). For this case, the Company conservatively forecasted Total Connections and New Load to grow only at the rate of inflation and calculated the amount of New Business expenditures that matched the inflation forecast. Table 21 on page 95 of my direct testimony provides more information on the forecasting method. This methodology conservatively estimates the true amount of New Business expenditures that will occur, as evidenced by the very strong five-year historic growth rate.

[139] 5 Tr 1628; Exhibit AG-14.
[140] 4 Tr 857.

> The forecasted Expected New Business expenditures of $11,818,000 for the 16 months ending April 2019 and $39,902,000 for the 12 months ending April 2020 are conservative forecasts and represent the funding necessary for the Company to ensure new business projects meet customer needs. Disallowance of these funds would not recognize the Company's obligations.[141]

This PFD finds that DTE Electric's projections for Connections and New Load, including New Business, should be adopted. As DTE Electric points out, the category to which New Business is assigned was overall overspent by August 2018, and DTE Electric's projections for the 2019 bridge period and the test year were estimated conservatively based on past spending plus inflation. This PFD further finds that the new business projects proposed for 2019 and 2020 are likely to materialize given the year-over-year increase in projects locating to DTE Electric's service territory, as Mr. Bruzzano explained. The Attorney General's disallowances are therefore rejected.

i. Infrastructure Resilience and Hardening/Redesign

Similar to the disallowances he proposed for 2018 New Business, Mr. Coppola compared January through August 2018 actual spending with the company's projected spending for the year. Mr. Coppola found that the company had underspent $8,711,000 for Infrastructure Resilience and Hardening, and $40,285,000 less than projected on Infrastructure Redesign. "However, giving the Company the benefit of the doubt that capital expenditures in the remaining four months will meet the forecasted level, it is reasonable to conclude that the cumulative under-spent amount[s] . . . for the 8 months ended August 2018 is likely to remain."[142]

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[141] 4 Tr 858.
[142] 5 Tr 1628-1630; Exhibits AG-15 and AG-16.

Because the ALJ has already adopted the Staff's proposed adjustments for 2018, 2019, and test period distribution operations, any additional adjustment is unnecessary and would be duplicative of the modification to this category that has already been made.

i. Non-Wires Alternative Pilot

DTE Electric proposed a non-wires alternative (NWA) pilot project consisting of an existing solar project and battery storage. Mr. Bruzzano testified that:

> Initial engineering analysis has determined that a battery storage facility could help with renewable integration by improving the voltage flicker seen during ramp-up, ramp-down or intermittent generation, and high voltage seen during high solar generation periods.[143]

Mr. Bruzzano added that the NWA project would provide benefits including a comparison of modeled power quality results to actual; defining and testing standards for battery interconnection; and development of expertise in battery management.[144]

Mr. Coppola disputed the value of the project, testifying that:

> The concept of a pilot is a misnomer in this situation. A pilot, such as the one that was used to launch the AMI implementation, is usually used to ensure that proven technology will work on a small scale and to sort out any problems before full implementation of the program. In this situation with the battery pilot programs, the Company is involved in early research and development work with technology firms. There is no proven product that can be readily implemented after a short pilot.[145]

Mr. Coppola testified that DTE Electric's efforts in this area are duplicative of efforts by other utilities, and DTE Electric should await the results of other pilots in order to build a business case for implementing any NWAs.

[143] 4 Tr 753.
[144] Id. at 753-754.
[145] 5 Tr 1631.

Mr. Bruzzano responded that it is important that the company stay current with new technologies and approaches, and he reiterated the benefits of the NWA pilot as set forth in his testimony.

In a related concern, on the same subject matter, Mr. Villareal testified that DTE Electric should place more emphasis on NWAs, including energy efficiency as a means to enhance system reliability and avoid more substantial capital costs for infrastructure. According to Mr. Villareal:

> Non-wires alternatives, as defined by Bruzzano, appear as storage, demand response, or rooftop solar generation. These are not the only types of resources that can be aggregated to provide NWA. Any discussion of NWA should include expanding energy efficiency offerings in the area. NWA can be targeted customer responses on the load side, or can be targeted distribution assets to replace or be added at the distribution level.
>
> In essence, a package of DR, storage, and EE can be used to better manage demand on a feeder or at a substation to minimize impacts of peak demand or added rooftop solar. In addition, a package of DR, storage, and advanced inverter usage could act as a distribution asset and address voltage or power quality impacts on a feeder. Indeed, NRDC and DTE are currently considering an NWA pilot that would utilize EE and DR.[146]

Mr. Villareal also suggested that DTE Electric could avoid or defer some capital investment costs associated with the 4.8kV hardening project, substation risk reduction project, and the City of Detroit Infrastructure (CODI) project by implementing more NWA, providing examples of other NWA projects undertaken by utilities.

Mr. Bruzzano responded that the projects cited by Mr. Villareal are driven by significant safety and reliability concerns, noting that the hardening, substation risk reduction, and CODI projects are:

> multi-year efforts to address system issues in a systematic manner. They are among the highest-priority projects and programs in DTE Electric's

[146] 7 Tr 2780.

> system and are proceeding at a rapid pace. NWAs as they exist today could not replace these programs not be executed with the urgency that is required.[147]

The parties' briefs generally followed the testimony of their witnesses.

This PFD finds that DTE Electric's proposed NWA pilot should be approved as presented. While the Attorney General is correct, NWA is a relatively new approach to distribution system management and enhancement, the company's proposal is modest and designed to take advantage of energy from an existing solar array while providing significant information about the performance of battery storage on the company's system. Mr. Villareal's recommendations merit consideration in future distribution planning, once the company completes this pilot and refines its Five-year plan. However, as the Commission has discussed, although NWA should be assessed as a potential solution in many situations, it is not necessarily an appropriate technology "when distribution investments must be made in a timely manner."[148]

i. Advanced Distribution Management System

Mr. Bruzzano provided extensive testimony supporting the company's proposed ADMS, including enhanced system functionality, high quality data acquisition, and benefits including safety, load relief, substation outage risk, and reliability as measured by improved SAIDI. [149] Mr. Bruzzano further explained:

> ADMS will be a critical enabler to the integration of Distributed Energy Resources DERs), such as rooftop solar, energy storage, and demand response. In fact, the Distributed Energy Resource Management System (DERMS) is an application that can be added to the ADMS platform the Company is implementing as the penetration of DERs increases on DTE

[147] 4 Tr 896.
[148] November 21, 2018 order in Case No. U-20147,p. 34.
[149] 4 Tr 759-766. Exhibit A-12, Schedule B5.4, page 9 shows the costs of the project.

> Electric's system. Because of the potential for DERs to swing power flows and voltage levels on the electric distribution system substantially, system operators must be able to monitor the condition of the grid in real time to ensure safe and reliable operations. In addition, an ADMS, with its underlying high quality data, historical information about system performance, and built-in modeling capabilities, can accelerate and simplify analysis about the impact of adding additional DERs to specific parts of the electric distribution network. None of this functionality is available today.[150]

Mr. Coppola opposed the inclusion of ADMS costs, testifying:

> Based on information provided by the Company in response to discovery, no other utility in the country has yet implemented the full ADMS suite of systems. A handful of utilities have implemented some of the subsystems. Therefore, the Company is an early adopter of a new technology with all the problems and drawbacks that come with being an early adopter. Being an early adaptor of new technology has risks. It is best to learn from the mistakes of others and implement technology that is proven, and in use for a few years with minimum failures.[151]

Mr. Coppola also questioned the benefit of the ADMS proposal, contending that Mr. Bruzzano's claimed reduction in SAIDI, when applied to all-weather interruptions, was less than 5%, insufficient to justify the high cost of the technology.

In rebuttal, Mr. Bruzzano testified that the ADMS project is well on its way to completion after extensive RFP and benchmarking processes. Mr. Bruzzano further explained that the ADMS project was initiated in part because many of the company's systems have reached end of life, "meaning that they are no longer properly supported by the vendors that supplied them." These systems are stable today, but the Company is at risk of recoverability if the systems fail."[152] Mr. Bruzzano also took issue with Mr. Coppola's characterization of the project as "risky" noting that all utilities with transmission and sub transmission have invested in some form of ADMS.

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151 5 Tr 1632.

152 4 Tr 869.

The parties' briefs and reply briefs recapitulated the testimony of their respective witnesses.

This PFD finds that the Attorney General's disallowance for ADMS should be rejected. Mr. Bruzzano presented persuasive testimony that ADMS is now common in the electric utility industry, and DTE Electric is implementing the various ADMS projects, in part, to address systems that have reached end-of-life. As discussed below, the Attorney General's recommendation to disallow deferred accounting for non-capitalized ADMS costs is also rejected.

i. System Operating Center

Mr. Coppola questioned the company's proposal for modernizing the company's primary and back up operating centers (SOCs), recognizing that "updating the two operating centers seems necessary," but nevertheless opining that the cost appeared excessive.[153] Mr. Coppola therefore recommended that, "the Commission direct the Company to make every effort to bring the final cost well within the $111 million, and to present more detailed costs and explanations of the necessity to incur such a large expenditure along with actions taken or to be taken to mitigate the total cost."[154]

In her initial brief, the Attorney General recommended that the Commission disallow the full $111 million cost of the SOCs, contending that the company failed to support the cost of the projects. In its reply brief, DTE Electric points out that because Mr. Coppola did not recommend a disallowance, the company did not file rebuttal testimony. DTE Electric contends that it is too late in the proceeding to address the

[153] 5 Tr 1635.
[154] Id.

Attorney General's proposed disallowance and it should therefore be rejected.

This PFD agrees that the Attorney General's recommendation to disallow the cost of the SOCs is untimely and should be rejected.

a. <u>Other Adjustments and Recommendations (4.8kV Hardening and Conversion)</u>

The Staff recommends that DTE Electric maintain a 10-year period between 4.8kV hardening and any 13.2kV conversion. DTE Electric agrees, with the qualification that:

> [T]he Company cannot perfectly predict customer connection patterns and load growth over a 10-year horizon, especially given the rebound in growth across its service territory. Circuits that have been hardened will only be converted when needed to support load growth, when cost savings justify it based on positive customer economics, or when reliability performance at the substation level require it.[155]

Soulardarity suggests that DTE Electric should be more focused on converting the 4.8kV system in the Detroit area, noting that more low-income customers are served by the less reliable, and less safe, 4.8kV system. According to Soulardarity:

> While the 4.8 kV Hardening program will delay the need for full conversion to the 13.2 kV system in those areas where it is implemented, it will deliver only incremental and inferior reliability improvements for those served by hardened 4.8 kV infrastructure. For example, the average restoration time for an outage on the 4.8 kV system is 70 percent longer than on the 13.2 kV system. Additionally, DTE projected a 65 percent decrease in downed-wire incidents as a result of 4.8kV hardening, as opposed to the 90 percent decrease from 13.2kV conversion. DTE also projected a 60 percent reduction in trouble events from hardening, as opposed to an 85 percent reduction from 13.2kV conversion.[156]

While Soulardarity's point is well taken, that there appear to be more issues with the company's system in low income areas, this seems to be the result of the fact that the system is simply much older in these areas than it is in other parts of the utility's service

[155] DTE Electric's reply brief, p. 43, citing 4 Tr 748, 855.
[156] Soulardarity's initial brief, pp. 13-14.

territory. There is nothing in the record that indicates that the company is spending a disproportionate amount in other areas, and it should be noted that some of the safety concerns that Soulardarity raises are a result of residual wiring from the Detroit Public Lighting Department. The Commission has opened investigations and initiated proceedings to address these specific issues.[157] Moreover, as DTE Electric points out in its reply brief, additional conversion activities will require additional funding. Moreover, as the company also points out, "4.8kV Hardening will provide about 80% of the benefits for about 16% of the costs ($660,000,000 vs. [$]4,200,000,000). A more complete conversion of the system to 13.2 kV would be extremely expensive (resulting in 'rate shock' to customers) with limited incremental benefits."

5. Advanced Metering Infrastructure

a. 3G to 4G Upgrade

In its initial brief, the Staff explains:

> In his testimony Staff witness Evans proposed a disallowance that included the Company's 3G to 4G communication upgrade. (8 TR 4102.) In order to avoid duplicate disallowances, Staff has only included witness Evans adjustments in Staff's Exhibit S-1 Schedule A1.
>
> * * *
>
> [I]f in the instant case the Commission does not accept Staff witness Evans adjustments to this line item, Staff urges the ALJ and Commission to adopt Staff's proposed disallowance of $8.450 million for the Company's 3G to 4G communication upgrade program.[158]

Because this PFD adopted the Staff's adjustments for distribution operations Strategic Capital, which includes AMI, Mr. Matthews' recommendation is already incorporated into the revenue requirement.

[157] See, e.g., September 28, 2018 order in Case No. U-18484.
[158] Staff's initial brief, pp. 27, 28.

b. Non-transmitting AMI

Mr. Matthews testified that in the investigation ordered in Case No. U-18203, the Staff determined that there are some purportedly non-transmitting AMI meters that are in fact sending signals, although the radios in these meters were supposed to have been disabled. In order to address this problem permanently, the Staff recommended that DTE Electric replace all AMI meters for AMI opt-out customers with digital meters that cannot transmit a signal. In addition, Mr. Matthews recommended that opt-out customers who are found to have transmitting meters should be refunded all opt-out fees.[159]

On December 20, 2018, the Commission issued an order in Case Nos. U-20084 and U-18486 approving a contested settlement agreement. Among other things, the settlement agreement provides:

> DTE Electric agrees to replace the meters of all electric customers currently electing service under the Company's Non-Transmitting Meter Provision (DTE Electric tariff C5.7), with digital meters that are not capable of transmitting any signals. DTE Electric will complete the replacement by December 2019, provided that the opt-out customers grant the Company access to facilitate the replacement. Before replacing an electric opt out customer's meter, DTE Electric will test the existing meter to determine if the radios are enabled and/or broadcasting. If the on-site tests, or other information available to DTE Electric, indicate that either one of the radios in the opt out customer's meter is still sending a signal, all monthly opt-out fees paid to date by the customer will be refunded including interest per the Billing Rules. No fee will be assessed to the opt-out customer for the meter replacement and DTE Electric will record a one-time credit as Contribution in Aid of Construction in the amount of $750,000 to offset the installation costs of the digital meters. The remaining current customers that do not have an AMI meter, and who elect to take service under DTE Electric's Non-Transmitting Meter Provision (DTE Electric tariff C5.7) will receive digital meters nontransmitting meters. DTE shall prepare quarterly reports on the progress of the meter replacement. The reports shall be filed in this docket each quarter beginning with the first quarter of 2019 until the meter replacements are complete.[160]

[159] 8 Tr 4139-4140.
[160] December 20, 2018 order in Case Nos. U-20084 and U-18486, Exhibit A, ¶ 3.

In its initial and reply briefs, the RCG suggests that the Commission should ensure that rates in this case are adjusted for any disallowances found in Case No. U-20084, and it contends that the number of opt-out customers with transmitting meters was understated in that proceeding. The RCG requests that the Commission "fully enforce and . . . further investigate DTE's settlement agreements in Case U-20084, and . . . rectify this situation in a complete manner[,]" reiterating that "[t]he Commission should also ensure that there are no rate impacts or costs that are included in this rate case associated with past over charges, disconnections, replacement of meters, and all other matters that are covered in its settlement agreement in U-20084[.]"[161]

It appears that the issues raised by the RCG were addressed in the above quoted settlement agreement. However, no ratemaking adjustments were made in the instant proceeding because the settlement agreement was not approved until after this record closed. Rate adjustments associated with the settlement agreement, if any, should be addressed in the company's next rate case.

c. *AMI Opt-out Charges*

In its initial brief, the RCG contends that the charge for customers opting out of AMI meter transmission should be significantly reduced or eliminated. The RCG contends that the company provided no evidence that the current charges are cost-of-service based, citing cross examination of Mr. Lacey and Ms. Robinson.[162] In its reply brief, DTE Electric points out that the Commission's determination that the initial opt-out charges were cost-of-service based has been affirmed by the Court of Appeals, as has the Commission's decision in Case No. U-18014 that opt-out charges need not be

[161] RCG's reply brief, p. 4.
[162] RCG's initial brief, pp. 11-13, quoting 7 Tr 3264-3266; 8 Tr 3969-3974.

revisited until AMI meter installation is complete.[163]

This PFD agrees with DTE Electric that the RCG's argument on opt-out charges should be rejected. The Commission addressed this matter in Case No. U-18014, and the Commission's decision was affirmed on appeal. The RCG does not bring any new evidence or arguments here.

6. Community Lighting Capital Expenditures

Ms. Zhou testified regarding DTE Electric's community lighting capital expenditures for 2017 through the projected period ending April 30, 2020.[164] Capital spending for community lighting was $11.3 million in 2017, and is projected to be approximately $13.0 million for 2018, $2.4 million for the 4 months ending April 30, 2020, and $12.8 million for the 12 months ending April 30, 2020. There were no objections to the company's proposed capital expenditures for community lighting. The Commission should therefore adopt DTE Electric's proposed amounts.

7. Demand Side Management Programs

Ms. Dimitry provided an overview of the company's various DSM programs including interruptible air conditioning, DTE Energy Insight, programmable communicating thermostats (PCTs) and other DSM programs. According to Ms. Dimitry, the company is proposing to spend $15.5 million through the bridge period ending April 2019, and $15.0 million in the projected test year on DSM programs.[165]

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[163] DTE Electric's reply brief, pp. 48-49, quoting *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)
[164] 5 Tr 1439-1449; Exhibit A-12, Schedule B5.5.
[165] 3 Tr 344; Exhibit A-12, Schedule B5.6, p. 1.

DTE Electric proposed PCT capital costs of $6.2 million for the 16 months ending April 30, 2019, and $3.4 million in the test year to purchase an additional 7,000 thermostats.[166] Ms. Dimitry testified that 2,000 customers had enrolled in the PCT program as of May 31, 2018, and that the company was forecasting that an additional 7,000 customers would enroll by the end of 2018.[167] According to Ms. Dimitry, the additional investments for the bridge period and test year would allow the company to enroll a total of 17,000 customers in the PCT program by the end of the test period.[168]

Ms. Dimitry discussed some preliminary results of the PCT program, testifying that PCT customers on the company's dynamic peak pricing (DPP) program reduced their usage an average of 1.0 kilowatts (kW), compared to DPP customers without PCTs, during three critical peak events called in September 2017.[169] Ms. Dimitry further indicated that DTE Electric would continue to measure and verify PCT energy savings and that the company is considering the efficacy of charging customers for the thermostats in order to better engage customers and increase participation in critical events.[170]

The Staff recommended disallowance of $9,593,000 for the bridge period and test year for PCTs. Mr. Matthews testified that in Case No. U-18014, the Commission approved funding for 10,000 PCTs and in DTE Electric's subsequent rate case, Case No. U-18255, the Commission denied the company's request for additional funding in light of

[166] In its order in Case No. U-18014, p. the Commission approved capital expenditures of $X.XX million for the purchase of 10,000 PCTs.
[167] Of the 2000 program enrollees, 65%, or 1,300 customers have actually installed the thermostats. 3 Tr 354.
[168] 3 Tr 351.
[169] 3 Tr 352-353.
[170] Id. at 354.

the low level of participation, despite the company's original projection of 10,000 enrollments per year over five years.[171] Mr. Matthews testified that, through discovery, the Staff updated the company's participation numbers and determined that as of September 30, 2018, a total of 3,000 customers had signed up for the program with a 2018 year-end forecast of a total of 4,500 participants, far short of the company's projections in its previous rate cases.[172] Mr. Matthews concluded:

> Based on the fact that the Company has failed to effectively complete its own enrollment goal in each of its previous rate cases, and that it has pushed its forecast of enrollment to later years in each case following its initial approval, Staff lacks confidence in DTE's commitment to the PCT program and recommends that before the Commission approves any additional PCTs, the Company needs to show a commitment to enroll enough customers to utilize the 10,000 PCTs approved in the Company's previous rate case. The Company's history of seeking recovery for PCTs and lackluster program enrollment suggests the Company's priority should be in marketing and outreach for its DR program. This is exemplified in the Company's DR portfolio investment decision with a proposed $15M for capital compared to a mere $375k in O&M for "Demonstrating and Selling Expenses."[173]

Mr. Matthews testified that if the company spends more on DSM that approved in this rate case, additional reasonable and prudent costs are recoverable through the DR reconciliation process as set forth in Case No. U-18369.[174] Mr. Matthews also recommended performance goals for certain DSM programs to be included in DTE Electric's IRP demand response plan.[175] In this case:

> Staff is recommending that the Company's performance goals for the test year be based upon the Company's own expected spending, less the aforementioned capital disallowance for PCTs, and peak MW reduction as found in Staff Exhibit S-12.3, page 6. Although actual performance may differ from the original expectation, it is helpful to establish program

[171] 8 Tr 4142.
[172] Id.; Staff Exhibit S-12.3, p 5.
[173] 8 Tr 4142-4143.
[174] 8 Tr 4143-4144.
[175] 8 Tr 4145-4146.

> expectations up front to help determine how a program might fit into a company's overall resource mix and understand the expected versus actual value of a program.

In rebuttal, Ms. Dimitry testified that the PCT program spending was justified, pointing to the "progress and success" achieved since first implementing the pilot program and the company's numerous outreach and education efforts on various traditional and social media platforms. Ms. Dimitry added, "[t]he Company's activities also include the purchase of equipment, as well as adequate software capability, specifically the Distributed Energy Resource Management System (DERMS), to execute IT integration and program implementation."[176] Ms. Dimitry also testified that in four peak events called during the summer of 2018, a range from 883 to almost 1,600 PCTs were involved showing an average reduction of 1.05 kW.[177] Ms. Dimitry further explained that even with the revised forecast of customer enrollments, from 7,000 to 4,500 by the end of 2018, the company is still on track to have 17,000 participants by early 2020. Ms. Dimitry opined that overall program success should not be judged solely by initial customer enrollments, pointing to DTE Electric's "Bring Your Own Device" program that has recently demonstrated much more rapid uptake by customers.[178]

With respect to the Staff's proposed performance objectives, Ms. Dimitry indicated that DTE Electric supports the Staff's recommendations in part:

> [T]he Company could support performance goals that are related to achieving planned capital investments and O&M costs consistent with its DR plan and also goals related to reduced demand resulting from its full set of DR programs. However, certain metrics such as customer enrollment, installation, or participation may be identified specifically for some of the pilots, programs or tariff-based rates as a way to track progress in launching a program, rather than to measure the overall success or effectiveness of a

[176] 3 Tr 385.
[177] Id. at 385.
[178] Id at 387.

particular program.[179]

The parties' briefs and reply briefs essentially track the testimony of their respective witnesses.

This PFD recommends that the Commission adopt the Staff's proposed $9,593,000 disallowance for PCT capital expense. As the Staff points out, DTE Electric is again asking for additional funding for a program where the company has not even achieved half the original goal of 10,000 participants set in Case No. U-18014, let alone the company's original objective of enrolling 10,000 customers per year for five years. Equally troubling is the fact that although the company presumably has approximately 4,500 customers enrolled in the program, only 65%, or less than 3,000 participants, have actually installed the PCT, assuming that the 65% installment percentage has continued. Nevertheless, as the Staff explained, DTE Electric may recoup additional, reasonable and prudent costs for PCTs, or other DSM programs, through the DR reconciliation process.

With respect to the Staff's recommended performance goals for DSM, this PFD agrees that such goals should be established as part of DTE Electric's overall demand response plan, subject to refinement over time through the IRP process. For the purposes of this case, the Staff's recommended performance goals (expected spending, MW reduction) should be adopted.

8. <u>Information Technology</u>

Mr. Griffin explained that IT capital expenditures are generally classified as: (1) IT for maintaining and enhancing service reliability; (2) IT for improving customer

[179] 3 Tr 388.

satisfaction; and (3) IT programs focused on containing costs.[180] Mr. Griffin testified that the most significant IT investments projected to be made in the bridge and test periods are spread over five "portfolios": Corporate Applications (including Corporate Services, Enterprise Applications, Financial Management, and Human Resources); Customer Service (including Business Planning & Development, Core Customer Service, and Electric Sales and Marketing); Plant & Field, Shared Infrastructure and Information Technology for IT.[181] Capital spending was $86.7 million in the 2017 historical test year, and is projected to be $169.3 million from January 2018 through the projected test period ending April 30, 2020.[182] The Staff proposed adjustments totaling $13,619,000 that are discussed below.

a. Corporate Applications—ConnectUs Phase 4 project

Mr. Griffin explained the advantages of the ConnectUs Phase 4 project, testifying that this method is superior to email for employee communication and collaboration. The Staff proposed to disallow the $625,000 capital expense on grounds that email was a reasonable means of communication and that even the ConnectUs technology has a time lag if employees are not monitoring the system. In its reply brief, DTE Electric points out that the project expense was previously approved in Case No. U-18255, where the Commission found that "this type of communications capability has become the norm."[183]

This PFD finds that the Staff's recommended disallowance should be rejected; nevertheless, it should be noted that in the company's previous rate case, this item was apparently called "Video Collaboration Program Phases 3 and 4." However, in this case

[180] 5 Tr 1353.
[181] 5 Tr 1356.
[182] 5 Tr 1350; Exhibit A-12, Schedule B5.7.
[183] 5 Tr 1400; April 18, 2018 order in Case No.U-18255, p. 18.

the company renamed the program ConnectUs, which apparently introduced confusion in the Staff's audit. As discussed above, if the utility decides to rename or reorganize its programs, it is obviously free to do so. But as part of its filing, DTE Electric should provide the necessary "crosswalks" and a clear explanation of how names or program elements (i.e., if moved from one expense category to another) have changed from the previous proceeding.

b. Customer Service—Customer Digital Channels (MSA) Sustainment project

Mr. Matthews recommended a disallowance of $535,000 from the bridge period, and $2,660,000 in the test year for the company's projected capital expenditures for Customer Digital Channels (MSA) Sustainment project. Mr. Matthews explained that this was a complete disallowance of capital expense for the project, on grounds that DTE Electric's proposal was based on historical spending on that category rather than project-specific, planned spending:[184]

> Staff's opinion is that since the IT and technology sectors are changing so rapidly, it is inappropriate to base a group of projects on simply what has been historically spent. If the Company is simply unable to provide any actual planned work in this area, it is more appropriate for the Company to request recovery of expenses after they have been incurred in a subsequent rate case.

In rebuttal, Mr. Griffin testified that the Staff's recommended disallowance was based on a misunderstanding of the explanation of the program contained in Exhibit A-12, Schedule B5.7.2 line 32a. According to Mr. Griffin, the spending addresses a backlog of IT enhancements that are prioritized throughout the years. Mr. Griffin explained:

[184] 8 Tr 4150; Exhibit 12.3, p. 9.

This list is constantly updated based upon the customer team's analysis of items on the list and anything that emerges either from the Voice of the Customer or from interaction with Staff. This allows the Company to react to changes in either the consumer experience or to the requests developed by the Commission or other customer advocates. Specifically, I stated in Staff Exhibit S-12.2,page 9 in response to CSM5.10a, that the scope includes the following over the next 12-18 months, including a priority focus on improvements, examples of which include:
-Response time enhancements
-Kiosk payment improvements
-Outage trouble reporting
-Improve Move in Move out process on web
-IVR outage reporting enhancements
-Enhancements to Agency website for supporting low income customers
-Managing Customer Profile Information/Functionality[185]

The company's initial brief relied on Mr. Griffin's testimony. The Staff acknowledged that given the rapid changes in the IT arena, it is difficult to predict spending years into the future, "[b]ut this difficulty, coupled with rapid changes in the field, is why the Commission should not approve funding for these expenditures based simply on a historical average rather than on detailed project information."

This PFD agrees with the Staff that its proposed disallowance, totaling $3,195,000 is reasonable. As the Staff contends, given the rapid advances in technology, historical spending is not necessarily a true indicator of projected spending. In addition, if the spending in this category represents a backlog, the company should be able to provide more detail on what it expects to accomplish in the bridge and test years.

c. *Plant & Field Work Management Sustainment (Maximo/ESri/Service Suit), Fuel Supply Sustainment, GenOps Business Sustain, IT FosGen Business Sustain, and Fermi—Nuclear GenSustain projects*

The Staff recommended that capital expenditures for these projects (as a group) be reduced by $542,000 in the bridge period and $2.61 million in the test year. Mr.

[185] 5 Tr 1408-1409.

Matthews testified that, “[w]hen asked for a more detailed breakdowns [sic] of the costs and proposed work included in these projects, the Company provided responses including the total expected costs for the included projects that were far below what was requested in this case.”[186] Accordingly, Mr. Matthews recommended only approving amounts that DTE Electric could support, as shown in Exhibit S-12.3, pages 10-12.

In rebuttal, Mr. Griffin testified:

> In general, business cases for 2019 and 2020 are in progress in accordance with the Company’s Annual Planning Cycle (APC). Based on where in that process the Company is, most 2019 and 2020 business cases have not been finalized and will continue to be worked through the scheduled completion of the APC. The APC is undertaken each year to align the capital projects with the planning roadmaps and to ensure that projects are prioritized and sequenced correctly. As part of the Part III Filing Requirement, the Company did provide draft business cases for anything that was in the top 25 project list as requested.[187]

Mr. Griffin continued, explaining that the 2019 business case will finalized in the mid-fourth quarter of 2018, and the 2020 business case will be finalized at the same time in 2019.

In its initial brief, the Staff argues that “the Company is asking for recovery of costs for projects that are still in the planning phase. . . . This lack of information about the project due to the Company’s own planning timeline is not a risk that ratepayers should be responsible for simply because of the timing of when the Company chose to file its case.” In its reply brief, DTE Electric reiterates that project planning is ongoing process, “so there is no sound basis for Staff’s apparent assumption that the draft point-in-time documentation represented the final version.”[188] Moreover:

[186] 8 Tr 4151.
[187] 5 Tr 1410.
[188] DTE Electric’s reply brief, p. 58.

> It bears emphasis that as indicated above, DTE Electric's process for any Sustainment case is an in-depth and ongoing analysis of continually-evolving backlogs of work driven by customer experience, enhancement requests, and maturing business needs. These backlogs are substantial and align to many years' worth of investment. The Company applies the methodology of the APC cycle specifically to prioritize and form an annual scope of work corresponding to the technology investment plans and roadmaps maintained for a multi-year period. This results in a body of work that routinely exceeds a single calendar year of effort, which is used as input into the APC cycle. It would also not be practical for the Company to produce, and for Staff to review, thousands of pages of documentation regarding each enhancement that makes up the Sustainment backlog, especially since none of the portfolio's backlogs will be completely exhausted in a single rate case period.[189]

This PFD finds, that as has occurred in past DTE Electric rate cases, the company has included "placeholder" amounts for these items identified by the Staff, with the intention of finalizing its spending plan at some point in the future. If the only information DTE Electric has available at the time it files its case is a draft plan, to which it apparently adds a financial "cushion," then it is reasonable for the Staff or other parties to the proceeding to base their respective projections on the company's draft and responses to discovery. Additional reasonable and prudent spending can be recovered in the company's next rate case. Accordingly, this PFD finds that the Staff's recommended disallowances should be adopted.

d. Customer Service—IT Business Planning and Development Sustainment and IT—Information for Technology IT—2018 Emergent, and coDE Sustainment projects

Mr. Matthews recommended a disallowance of $3.437 million test period and $2.733 million in the bridge period, testifying that because spending on this group of projects is classified as for "emergent," needs, and "[w]hile, Staff understands that not all

[189] Id.

expenses in a given category can easily be projected, due to the nature of a future looking test period and the guaranteed recovery of these projections once approved," it nevertheless inappropriate for DTE Electric to recover these costs in rates "given the uncertainty of these projects."[190] According to Mr. Matthews, given the significant uncertainty in the projects and associated spending, the rate request associated with these items is more like contingency.

In rebuttal, Mr. Griffin testified that these projects have a significant backlog of upgrades and enhancements that need to be undertaken, noting that prioritization of these projects is ongoing. Mr. Griffin also opined that Mr. Matthews did not fully understand what the company meant by 2018 "emergent" programs, which allow the company to take advantage of technology trends and advancements.[191] Mr. Griffin referenced DTE Electric's Innovations Project Management Office (iPMO), "which governs the emergent initiatives, experiments and projects represented within this case. The iPMO assesses the potential value and strategic alignment of emerging technologies and trends by designing experiments, conducting workshops and documenting their results to determine whether an innovative idea has real business value."[192]

Again, this PFD agrees with the Staff that, in light of the uncertainty about the need for the projects, coupled with the unknown cost of emergent items, the Staff's recommended disallowances are reasonable and should be adopted.

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[190] 8 Tr 4149-4150; Exhibit S-12.3, page 8.
[191] 5 Tr 1404.
[192] 5 Tr 1405.

e. <u>Information Technology Reporting</u>

Mr. Matthews testified that in DTE Electric's next rate case filing, the company should include:

> -Future IT project-level detail should include a breakdown of both the O&M and capital costs. O&M costs should be broken down into two or three sub-categories.
> -For each project the Company should submit a project approval document after the project preliminary analysis phase that includes:
>
> 1. A brief synopsis describing the project
> 2. The project approval date
> 3. The incurred expenditures to date (Operations and Maintenance Cost (O&M)
> 4. The total project estimated O&M and capital cost through project 4implementation
> 5. Any necessary approvals by the Company's management with appropriate expenditure approval authorization (per documented company policy)
> 6. Any approved change management documentation if the total project estimate grows by greater than 10% or $50,000 (whichever is greater). For IT projects over $100,000, the Company will include as an exhibit. The Company will include as an exhibit a copy of the written, PowerPoint, or other media presentation that the Company's technical staff used to present the project justification and alternatives considered by Company senior management.
>
> -Analysis that shows the Company considered cloud computing alternatives in IT project expense requests over $100,000 excluding cyber security or transmission ontrol IT projects. Because the above criteria is submitted does not mean that cloud-based solutions will automatically be approved by the Commission. Staff is also recommending that in future cases the Company include in its testimony breakdown of any IT programs that were approved in its previous rate case that were not completed or were 20% above or below the approved project amount with an explanation of why the project was not completed, or why it was off budget. Staff would expect this breakdown to include the approved project cost as well as what was spent on the project in this breakdown. Due to the ever- increasing number of IT projects the Company presents in a given rate case, it would be beneficial to all intervenors and the Commission to provide assurance that the programs that were approved are being completed within budget, and this information would provide that assurance.

Mr. Griffin did not take issue with many of these reporting requests, with the qualification that the presentations and information that the Staff asks for should be limited to only those projects costing $500,000 or more. Mr. Griffin noted that the large number of IT projects, and the fact that many of them are smaller projects, would make the submission of a business case, management changes, and project approvals for all IT projects burdensome.

Mr. Griffin however disagreed with the request to provide over- or under-budget amounts of 20% or more for projects, or a description of projects that were not completed, explaining that this information could be obtained in the discovery and audit process. Mr. Griffin testified:

> [R]equiring the Company to provide this type of comparison should only apply to projects over the proposed $500,000 threshold and then only for those projects where additional recovery was being sought in the current rate case. The amount of resources and time required to explain and justify projects within the current rate case bridge and test periods is already extensive. Adding to that the additional work that will be required if the MPSC accepts and implements the other suggestions being put forward by Witness Matthews will only serve to significantly increase that burden. The suggestion that it would also be necessary to report on outcomes of a previous case, unless it has bearing on additional recovery in this case, can only serve to inflate this resource requirement beyond reasonable levels and risk introducing confusion if current testimony is co-mingled with past case data.[193]

In its initial brief, the Staff explained:

> Staff believes that the Company should be held accountable for its projections in its IT programs and should show that programs are not only being funded and completed, but also being done within budget. Staff's final recommendation of providing a breakdown of any IT programs that were approved in its previous rate case that were not completed or were 20% above or below the approved project amount will provide Staff and the Commission the assurance necessary to see that DTE is completing its preapproved projects in a timely manner and within budget. For this reason, the ALJ and Commission should adopt Staffs recommended filing suggestions with DTE's modification for all but Staff's final recommendation.[194]

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[193] 5 Tr 1417.
[194] Staff's initial brief, p. 26.

The PFD finds that the Staff's recommended reporting requirements, with the spending level modifications set forth in its initial brief and including reporting on past IT projections and spending, should be adopted. IT appears to be something of a new frontier in spending projections, especially considering the fast pace of change in this area. Information about the accuracy of past projections, including project over-or under-budgeting and programs or projects where funding was approved but where the project itself was cancelled or abandoned, would provide much-needed transparency for this increasingly important spending category. Accordingly, this PFD recommends that the Staff's recommended reporting requirements for IT capital expense be adopted.

9. Corporate Staff Group Capital Expenditures

Ms. Uzenski provided testimony regarding historical and projected capital expense for Corporate Staff Group (CSG) items. Ms. Uzenski explained that the CSG provides a number of administrative and general services to various DTE Energy companies.[195] Exhibit A-12, Schedule B5.8 shows CSG capital expenses in the areas of EV fleet, facilities upgrade and construction, facilities renovation, service center upgrades, HQ Energy Center, NERC compliance, and other.

The Attorney General proposed two disallowances related to Corporate Staff Group (CSG) capital expenditures proposed by DTE Electric. The first, a $17,052,000 reduction, was based on the company's historical spending in this area. And the second relates to the company's HQ energy center project. These recommendations are addressed *ad seriatim*.

[195] 7 Tr 3310.

a. Corporate Staff Group 2018 Disallowance

Mr. Coppola observed that in 2018, the company projected $114,385,000 for CSG support, but as of the eight months ending August 2018, the company had only spent $47,901,000 of the $64,953,000 it projected to spend, a difference of $17,052,000 or 26%.[196] Mr. Coppola testified:

> The $17.1 million is a significant variance from the forecasted level and this under-spending trend is likely to continue into the remaining months of 2018. However, giving the Company the benefit of the doubt that capital expenditures in the remaining four months will meet the forecasted level, it is reasonable to conclude that the cumulative under-spent amount of for the 8 months ended August 2018 is likely to remain. Therefore, I recommend that this amount be removed from the projected capital expenditures and from rate base.[197]

The company did not appear to have responded to Mr. Coppola's recommended disallowance in testimony or in its briefs. Absent evidence to the contrary, this ALJ finds that the Attorney General's proposed reduction of $17,052,000 to 2018 capital expense for CSG is reasonable and should be adopted.

b. Headquarters Energy Center

Ms. Uzenski explained that DTE Electric is proposing to construct a new energy center (HQ Energy Center) to supply steam and chilled water to the company's headquarters. Ms. Uzenski explained that DTE Electric currently relies on Detroit Thermal for steam service and steam rates have increased approximately 5% per year since 2013. In addition, Ms. Uzenski stated that Detroit Thermal will need to upgrade its system in the future, driving rates higher.[198] Ms. Uzenski observed that by constructing and owning a steam system will allow the company to better control costs and avoid problems will steam

[196] 5 Tr 1640. Mr. Coppola explained that these amounts had been adjusted to remove the costs of the HQ Energy Center.
[197] 5 Tr 1640-1641; Exhibit AG-20.
[198] 7 Tr 3318.

leaks from the Detroit Thermal system that has caused damage to the company's facilities.[199]

Ms. Uzenski testified that the company's chilled water system is at the end of its useful life stating, "There is significant rust on the structures, plugging within the chambers that is negatively impacting efficiencies and output capabilities, and failing components such as valves and motors." Ms. Uzenski added that the new system will replace seven old units with four high-efficiency units.

> In addition, the chillers can be sized as needed based on demand. With the existing units in the high-rise building (WCB) two chillers must be used on a day when fewer tons of cooling are required, creating inefficiencies. The new chillers will have trim capabilities so that energy will not be wasted throughout the entire complex. Routine maintenance activities for the chilled water system are expected to be simplified, and the cost of maintenance reduced by using standardized equipment. The centralization of the chilled water system will also reduce labor needs as monitoring and control will take place at one location versus two separate buildings to meet City of Detroit requirements.[200]

Ms. Uzenski testified that the NPVRR of the $32.5 million project is approximately $50 million, compared to $54.1 million for the status quo.[201]

Mr. Coppola recommended that the total cost of the HQ Energy Center be disallowed. Mr. Coppola determined through discovery that the company had not negotiated with Detroit Thermal for a lower rate for steam, and had not requested that Detroit Thermal address the issues with steam leaks.[202]

Mr. Coppola also contended that the company's analysis shows that, assuming that Detroit Thermal rates continue to increase at 5.2% per year, continuing service with

[199] Id. at 3319-3320.
[200] Id. at 3319.
[201] 7 Tr 3320. Ms. Uzenski also testified that the project cost included $4.5 million in contingency, which the company removed.
[202] 5 Tr 1641; Exhibit AG-21.

Detroit Thermal would be $17.7 million less than building the new energy center.

In its reply brief, DTE Electric repeats the benefits listed in Ms. Uzenski's testimony and points out that the HQ Energy Center addresses two problems at once. The Attorney General argues that the project is not financially justified and that the company failed to explore other solutions for the problems with Detroit Thermal.

This PFD finds that the HQ Energy Center, the cost of which has been reduced by $4.5 million, is reasonable based on the record in this case. As DTE Electric argues, the new facility will address not only steam issues, which were not limited to increasing steam rates alone, but is intended to replace the company's chilled water system that has reached end of life.

B. Depreciation

There appear to be no disputes over the company's depreciation reserve. Adjustments should be made consistent with the final order in this case.

C. Working Capital

In its initial brief, the company made a $44.6 million working capital reduction in the Prepaid Pension Asset to correct an error in the Company's filing; and an $800,000 working capital correction to remove a double count of the company's proposed Charging Forward Regulatory Asset. Issues concerning the Charging Forward regulatory asset are discussed in more detail below. The Attorney General and ABATE recommended specific adjustments to company's working capital that are addressed below.

1. Reduced Emissions Fuel Credit

Mr. Coppola recommended that DTE Electric's working capital amount be adjusted by $21.9 million to recognize a probable extension of the reduced emissions fuel (REF) tax credit. In rebuttal, Ms. Wisniewski testified that it was highly unlikely that the tax credit would be renewed, noting that "DTE Energy's Tax Organization closely follows the status of proposed tax legislation, especially as it pertains to REF." She added that the tax credit has been applied to facilities that were brought in service by the end of 2011, and even if the tax credit is extended it will likely only apply to new facilities and not to the company's existing facilities.

This PFD finds the company's argument persuasive, and agrees that the Attorney General's proposed adjustment for the REF fuels credit should not be adopted. As the company points out, even if the tax credit is extended, it is likely that the credit will only apply to new facilities.

2. Short-term Investments Recorded as Cash

Mr. Coppola testified that in the company's $14.7 million cash amount in working capital, DTE Electric included $3.5 million in short-term investments in affiliates that earn interest. Mr. Coppola testified that this amount should be removed consistent with prior Commission orders.[203] In rebuttal, Ms. Uzenski pointed out that, as shown in Exhibit A-12, Schedule B4, "short term investments with affiliates is reflected in line 8, Notes Receivable, not in line 7, Cash. The $3.5 million amount supplied in response to discovery request AGDE-4.245 represented the average amount of loans to affiliates in 2017. It did

[203] 5 Tr 1654.

not represent the amount that was included in the projected period, which was assumed to be $0."[204]

This PFD agrees with DTE Electric, that the $3.5 million in loans to affiliates, as explained by Ms. Uzenski, was not included in working capital, and therefore need not be removed.

D. Rate Base Summary

Based on the adjustments set forth above, this PFD finds that DTE Electric's rate base is $ 16,999,569,000 for the test year, on a total company basis. This is comprised of a net plant amount of $ 15,409,100,000 and an allowance for working capital of $1,478,407,000.

V.

CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure

1. Debt and Equity Balances

Mr. Solomon testified that DTE Electric is proposing a permanent capital structure comprised of 51% equity and 49% debt, noting that the company is requesting an increase to the equity ratio, over that approved in Case No. U-18255, "at a time when it is facing the material, negative impacts of the . . . ('TCJA' or 'tax reform')."[205] Mr. Solomon added that "[t]he increased equity level is especially important given the significant capital

[204] 7 Tr 3352.
[205] 5 Tr 1040-1041; Exhibit A-14, Schedule D1.

investments the Company is making over the next 5 years to maintain and improve the electric infrastructure to benefit our customers."[206]

Mr. Solomon explained that the TCJA has a negative impact on the utility sector due to its impact on cash flow and, in turn, utility credit metrics. Mr. Solomon pointed to a 2018 report from Moody's investor services (Moody's) that downgraded the entire utility sector due to lower cash flows and higher debt levels from increased capital spending. "The combination of the loss of bonus depreciation and a lower tax rate means that utilities lose some of their cash flow contribution from deferred taxes."[207] Mr. Solomon further noted that prior to the 2018 downgrade of the entire utility sector, Moody's downgraded the outlook of 24 utilities, and Standard and Poor's (S&P) also revised the outlook to negative for five utilities on the basis of regulatory response to the TCJA.[208] Mr. Solomon testified that on May 30, 2018, Moody's put DTE Gas on a negative outlook due to weakened credit metrics resulting from the TCJA.[209]

With respect to DTE Electric specifically, Mr. Solomon explained:

> DTE Electric's cash flow credit metrics, including Funds from Operations ("FFO") to Debt are materially weakened post tax reform. FFO to Debt is a key metric the credit rating agencies use to measure the credit quality of a utility. Exhibit A-14 Schedule D1.3 shows DTE Electric's FFO to Debt calculation as of December 31, 2017 (pre-tax reform) and a pro forma calculation given the impacts of the TCJA (post-tax reform). The financial metric was calculated using S&P's methodology. The Company's FFO to Debt at December 31, 2017 was 21.2% pre-tax reform and is 17.8% post-tax reform, a 3.4% decline. This significant and material decline in a key credit metric is further evidence that the Company needs to maintain a strong balance sheet to avoid a potential downgrade or a deterioration in credit ratings outlook.[210]

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[206] *Id.* at 1041.
[207] 5 Tr 1041-1042.
[208] 5 Tr 1042-1043.
[209] *Id.* at 1043.
[210] 5 Tr 1043.

Mr. Solomon cited examples, from Florida, Georgia, and Alabama, where regulators purportedly allowed for tax reform relief in the form of increased equity ratios.[211] Mr. Solomon further explained that the 51% equity ratio DTE Electric is requesting here is lower than its peer group and is lower than the Commission-authorized equity ratios for other major utilities in Michigan.[212] Mr. Solomon added that when considering the adjustments to debt made by ratings agencies, which include unfunded pensions, operating leases and other items, the adjusted peer group equity ratio is 47.8% compared to 44.6% for DTE Electric.[213]

Finally, Mr. Solomon stressed the importance of a solid investment grade rating to the company's plans to invest $4 billion in capital improvements from January 2018 through the end of the test year, noting that the company has been, and remains, committed to maintaining a 51% equity balance, noting that this commitment is demonstrated by the significant equity infusions (totaling $1.7 billion) from DTE Electric's parent company since 2006, adding that DTE Electric has planned equity infusions of $372.2 million in 2018, $200 million in 2019, and $200 million in January to April 2020, which will result in a 51% equity ratio for the projected test period."[214]

On cross-examination, Mr. Solomon admitted that DTE Electric was not one of the companies that received a negative outlook from Moody's in January and that the 24 companies that did receive a negative outlook may have had less favorable financials before the TCJA. He noted, however, as was the case with DTE Gas, Moody's continues to monitor utilities and may place a company on negative outlook at some other point in

[211] Id. 1044-1045.
[212] Id. 1045-1046.
[213] 5 Tr 1046; Exhibit A-14, Schedule D1.2.
[214] 5 Tr 1047-1048.

time.[215] Mr. Solomon also explained that being placed on a "negative outlook" is not the same as a credit downgrade.[216]

Dr. Vilbert similarly testified that that the TCJA has had significant impacts on the regulated utility industry, citing the same Moody's and S&P reports cited by Mr. Solomon as well as a report from Fitch Ratings (Fitch), which estimated a 15% decrease in FFO due to the TCJA, and which referenced regulatory actions that might mitigate the effects of the TCJA such as an increase in equity ratios or higher ROEs.[217] Dr. Vilbert explained that cash flow to debt ratios are closely monitored by ratings agencies and a decrease in FFO could negatively affect credit ratings. Dr. Vilbert added that DTE Electric plans to issue an additional $300 million in equity to maintain its BBB credit rating.[218]

Mr. Coppola recommended that DTE Electric's capital structure be rebalanced to 50/50 debt to equity by removing $131 million from common equity and adding that amount to long-term debt. Mr. Coppola noted that this reflects the same capital structure approved in the company's most recent rate case.[219]

Mr. Coppola testified that DTE Electric provided no support for its proposed increased common equity balance and that the average equity balance for the company's peer group is 47.6%.[220] Mr. Coppola noted that:

> [T]his lower average common equity level supports these companies' utility operations, as well as non-utility operations which tend to be somewhat more risky. The riskier non-utility operations require a higher common equity cushion to maintain similar credit ratings. Therefore, if we adjusted for the higher equity capital required by the non-utility businesses, the equity

[215] 5 Tr 1084.
[216] Id. at 1085.
[217] 6 Tr 1935-1936.
[218] 6 Tr 1936.
[219] 5 Tr 1656; Exhibit AG-25.
[220] Mr. Coppola later explained that even if two outlier companies were removed, the common equity ratio would be 48%. 5 Tr 1658.

> capital for the utility portion of the peer group's capital structure would be even lower.[221]
>
> * * *
>
> The cost of equity for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure. Thus, it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible in order to have consistency with the cost of equity capital derived from those peer group companies. The Company's proposed common equity capital ratio of 51 .0% creates a disconnect that is not acceptable and is also more costly to customers.[222]

Next, Mr. Coppola opined that there is little difference, in terms of risk, between DTE Electric and Consumers Energy Company (Consumers), observing that in its order in Case No. U-17790, the Commission directed Consumers to move to a balanced 50/50 capital structure. Thus, Mr. Coppola testified that the same capital structure should apply to DTE Electric. Mr. Coppola also pointed out that DTE Energy can determine the equity portion of any of its subsidiaries, including DTE Electric, and that DTE Energy management can make an equity infusion at any time if necessary.

Mr. Coppola described the company's presentation on the need for a higher equity balance as "incomplete and somewhat misleading." For example, Mr. Coppola testified that the Moody's announcement of the negative outlook for DTE Gas shows that the downgrade was the result not only of the TCJA, but also that company's commitment to record high capital spending levels. Mr. Coppola added that in response to a discovery request, the company indicated that DTE Gas had made no changes to its capital spending. Thus, according to Mr. Coppola, "It is then apparent that [those] who make

[221] 5 Tr 1657; Exhibit AG-27.
[222] 5 Tr 1658.

capital structure and financial decisions for both DTE Gas and the Company, are not highly concerned about the Moody's negative outlook and its ramifications."[223]

Mr. Coppola also disputed Mr. Solomon's references to actions by regulators in Florida and Georgia, noting that these actions were not in response to adverse credit metrics resulting from the TCJA. Specifically, Mr. Coppola explained that the response in Florida, allowing three companies to retain, rather than refund, excess tax payments, was precipitated by the need for post-hurricane reconstruction. In Georgia, where regulators allowed a temporary increase in Georgia Power's equity ratio from 51% to 55%, was the result of a settlement addressing the financial hardship stemming from problems that had arisen in the construction of two nuclear power plants.[224]

Mr. Coppola disputed the significance of the reduction in the FFO to debt ratio calculated in Exhibit A-14, Schedule D1.3. Mr. Coppola agreed that the exhibit showed a decrease from 21.2% to 17.8% in FFO/debt, but pointed to a company discovery response that indicated that "the Company's S&P debt ratings could be imperiled if the FFO/Debt ratio were to fall below 13%," a ratio significantly lower than 17.8%.[225]

Mr. Coppola testified that DTE Electric confirmed that it has not been placed on a credit watch by any of the ratings agencies and questioned the company's claim that a downgrade could increase debt interest rates by 25-50 basis points, an amount the company could not justify. "Assuming for sake of argument that a downgrade would occur, which is a remote possibility, the increase in interest expense from a 24 basis point increase in interest rates is insignificant in comparison to the Company

[223] 5 Tr 1659-1660.
[224] 5 Tr 1660-1661.
[225] 5 Tr 1661 citing DTE Electric response to discovery request AGDE-1.26c.

having a higher equity ratio."[226] Mr. Coppola explained that increasing the equity balance in DTE Electric's capital structure would increase the revenue requirement by approximately $11 million.[227]

Mr. Walters disagreed that DTE Electric has an increased risk profile compared to the proxy group of companies. He added that "based on the substantial increase in DTE Electric's forecasted dividend payments to its parent company, it is reasonable to conclude that the proposed increase in its common equity ratio is a means to provide cash to shareholders rather than stabilize the financial well-being of the utility."[228] Mr. Walters presented a table, based on company workpapers, showing projected dividends for 2019 and the test period.[229] According to Mr. Walters, DTE Electric is planning to increase its dividend payments by $86.7 million in 2020 over the amount paid in 2018, resulting in "a payout ratio in 2020 of 136.4% relative to a payout ratio of 72.9% in 2018. . . Similarly, for the projected test year ending April 30, 2020, DTE is expected to pay out 112.7% of its net income in dividends."[230] Mr. Walters concluded that because DTE Electric's higher common equity ratio is largely related to increasing its dividends, the company's request is unreasonable.

In rebuttal, Mr. Solomon testified that that Mr. Coppola calculated equity ratios for the peer group holding companies and not the subsidiary utilities. When only the regulated utility information is used, Mr. Solomon calculated an average common equity ratio of 51.6%[231] Mr. Solomon testified that he agreed with Mr. Coppola that Consumers

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[226] 5 Tr 1662-1663.
[227] Id. at 1663.
[228] 7 Tr 2970.
[229] 7 Tr 2971, Table 5.
[230] 7 Tr 2971.
[231] 5 Tr 1061; Exhibit A-35, Schedule Y-1.

and DTE Electric are comparable and, as such, should have similar capital structures, noting that Consumers currently has an equity ratio above 52%.[232]

Mr. Solomon disputed the claim that Moody's placed DTE Gas on a negative outlook for reasons other than the TCJA, opining that "Moody's would not have placed DTE Gas on negative outlook if tax reform had not occurred." And, while capital investments are at a record high for DTE Gas, DTE Electric has also planned substantial capital investments over the next several years. Thus, according to Mr. Solomon, "a common equity ratio of 51% is reasonable given the negative impact of tax reform on credit metrics especially during a time of increased capital expenditures."[233]

In rebuttal to the Staff, Mr. Walters objected to Mr. Megginson's decision to adopt the capital structure proposed by DTE Electric, claiming that the Staff's position was unsupported. Mr. Walters further contended that accepting the company's capital structure was contrary to Mr. Megginson's testimony that no adjustments due to the TCJA are warranted at this time.[234]

In their briefs and reply briefs, the parties largely relied on the testimony of their witnesses. DTE Electric pointed out that companies with stronger capital structures have better access to capital at a lower cost. DTE Electric contended that in the company's previous rate case, the Commission declined to increase the equity layer in the company's capital structure because conditions had not changed sufficiently to warrant a departure from the balanced capital structure that the company had at the time. Now, however, the combined effects of the TCJA and DTE Electric's aggressive capital

[232] 5 Tr 1062.
[233] 5 Tr 1063.
[234] 7 Tr 3029

investment program merit a change from 50% equity to 51% in the company's equity ratio.[235]

The Attorney General asserts that the common equity ratio of the peer group used to determine ROE in this case is 47.6%, which is used to support both utility and riskier non-utility operations. The Attorney General reiterates that the Commission has directed Consumers Energy, a company similar to DTE Electric, to return to a balanced capital structure and it is reasonable to expect the same of DTE Electric, and DTE Energy can provide additional capital any time it wants.[236] The Attorney General points out that increasing the equity ratio to 51% increases the revenue requirement by $11 million.

ABATE repeats that DTE Electric intends to increase its dividend payment by $886.7 million in 2020, or 18.8% over 2018 levels, leading to a payout ratio of 136.4%. ABATE quotes Mr. Walters' testimony that "it is reasonable to conclude that the proposed increase in its common equity ratio is a means to provide cash to shareholders rather than stabilize the financial well-being of the utility."[237] ABATE notes that Mr. Walters' testimony regarding prospective dividend payouts was unrebutted.

The ALJ agrees with the Attorney General and ABATE that DTE Electric failed to provide sufficient evidence that its capital structure should be adjusted at this time to compensate for the purported impacts of the TCJA and the company's capital spending program.

DTE Electric makes the following arguments in support of increasing its equity balance to 51%: (1) the TCJA and loss of bonus depreciation "causes utilities to lose

[235] DTE Electric's initial brief, p. 47.
[236] Attorney General's initial brief, p. 86.
[237] ABATE's initial brief, p. 29, quoting 7 Tr 2970.

some of their cash flow contribution from deferred taxes[,]" thereby reducing the FFO to debt ratio, "a key metric that credit rating agencies use to measure credit quality[;]"[238] (2) the entire regulated utility sector, as well as DTE Gas specifically, have been placed on a negative outlook; (3) regulators in other states have recognized the impacts of the TCJA and have increased equity ratios in response; (4) like DTE Gas, DTE Electric is planning significant capital investments over the next two years and must maintain its high credit rating; and (5) DTE Electric's currently-approved equity ratio of 50% is lower than its peer group and lower than comparable Michigan utilities.

While DTE Electric cites a number of factors that might have some effect on the company's credit ratings, the ALJ notes that as of the close of the record in this case, the TCJA had been in effect for almost a year, with no discernable impact on the company or its strong credit ratings. The ALJ also finds unavailing the company's claims about the negative outlook for the entire utility sector, or certain specific utilities. As other parties point out, most of these utilities on a negative outlook already had less-than-optimal financials before the TCJA was enacted. This is especially true with two of the specific examples in Florida and Georgia that the company cited. The regulatory responses in those states appears to be highly correlated with the exceptional damage from Hurricane Irma in Florida, and the serious problems with two nuclear plants under construction in Georgia. As for the negative outlook for the entire sector, as Mr. Solomon admitted, a negative outlook is not the same as a credit downgrade.

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[238] DTE Electric's initial brief, p. 47.

While DTE Electric dismisses ABATE's position, claiming it "adds nothing to the analysis,"[239] the ALJ agrees with ABATE that Mr. Walters' testimony regarding the company's plans to significantly increase its dividends by 2020 was unrebutted, as was Mr. Coppola's testimony that DTE Electric could only demonstrate a possible increase in interest rates of 24 basis points at a cost, even if it did occur, that would be insignificant compared to the increase in equity ratio requested here. Accordingly, the ALJ finds that DTE Electric has not provided sufficient evidence to show that the equity portion of its capital structure should be increased at this time.

2. ABATE "Regulatory Plan"

Ms. Wisniewski explained the effects of the TCJA on the company's accumulated deferred tax balance and projected federal income tax expense. She explained that DTE Electric remeasured its deferred tax balance as of December 31, 2017, to reflect the new corporate tax rate. Based on the company's estimate at that time, the deferred tax balance was reduced by $1.4 billion, and a corresponding deferred tax regulatory liability was created. She explained that $0.1 billion of this amount relates to non-base-rate surcharges, leaving $1.3 billion to be addressed in this case, consistent with the Commission's December 27, 2017 order in Case No. U-18494. Ms. Wisniewski testified that the company proposes to return the deferred tax regulatory liability to ratepayers as shown in her Schedule C8.1 of Exhibit A-13. As shown in this exhibit and as she explained, the $1.3 billion in excess deferred taxes has three components. The "Protected Plant" balance represents "the excess deferred taxes related to the cumulative difference between accelerated tax depreciation and book depreciation," and is required

[239] DTE Electric's reply brief, p. 68.

under the TCJA to be returned to customers using the Average Rate Assumption Method (ARAM). As shown in column b of Schedule C8.1, the annual amortization amounts vary, reflecting the requirement to use vintage accounting. DTE proposes to amortize the “Unprotected Plant” balance using a 23-year straight-line method based on an estimate of the remaining life of the plant assets, and proposes to amortize the “non-Plant” balance using a 14-year straight-line method based on the largest tax timing difference reflected in the balance. These amortizations are shown in columns c and d of Schedule C8.1. Ms. Wisniewski testified that DTE Electric proposes that the amortizations begin May 1, 2019, with the projected test year amortization of $54.9 million reducing federal income tax expense as shown on line 57 of Schedule C8 in Exhibit A-13.

Recognizing that DTE Electric was only able to estimate the excess deferred taxes at the time of its filing, Mr. Nichols explained that Staff obtained updated information from the company with the final amounts for the remeasurement of deferred taxes, resulting in an increase in the projected test year amortization of $411,000. In its initial brief, DTE Electric makes clear that it adopts this update.

ABATE proposed an alternative amortization for a portion of the excess deferred taxes. Mr. Gorman proposed a “Regulatory Plan” to accelerate the amortization of a portion of the Adjusted Deferred Income Tax (ADIT) balance as an offset to increased depreciation expense attributable to the early retirement of Belle River and the Tier 2 units, and to the carrying costs attributable to the company’s construction of a new NGCC plant, the Blue Water Energy Center.[240] He explained that under Internal Revenue Service rules, only a portion of the ADIT balances, referred to as “excess ADIT,” may be

[240] 7 Tr 2903-2918.

accelerated.[241] In Table 2 of his testimony,[242] he presents the revenue requirement attributable to the plant retirements and the new gas plant, with offsetting amortization of excess ADIT under both DTE Electric's proposal and ABATE's proposal. Table 2 shows that DTE Electric's proposed $74.1 million annual amortization of excess ADIT leads to a net increase of $120 million in the cost of service, while ABATE's proposed $245.9 million annual amortization of excess ADIT leads to a new reduction of $50.8 million in the cost of service, or $171.6 million less than under DTE Electric's proposal. Mr. Gorman explained his calculation of the increased depreciation rates for the retiring units, also presenting the calculations in Exhibit AB-33 and a summary in Table 4 of his testimony.[243] He testified that the accelerated depreciation of these units would increase the cost of service by $122.9 million.[244] He also explained his calculation of a $38 million incremental revenue requirement associated with the Blue Water Energy Center.

Mr. Gorman testified that DTE Electric rates are already expensive in comparison to the Upper Midwest Region as shown in his Exhibit AB-34, with an additional burden from the accelerated plant depreciation and new plant expenses. In support of ABATE's proposed accelerated amortization of excess ADIT balances, he explained;

> [T]here is a unique opportunity to mitigate these extraordinary production costs in this case, that provides accelerated recovery of Tier 2 and Belle River coal unit costs, and current recovery of pre-in-service AFUDC costs for the [Blue Water Energy Center] unit, but reduces impacts on retail customers.[245]

[241] 7 Tr 2904, 2913-2914.
[242] 7 Tr 2905.
[243] Id. at 2909.
[244] Id. Note that Mr. Gorman's Table 2 and Exhibit A-33, page 1, appear to pick up an incorrect revenue requirement of $121.568 million for the accelerated depreciation attributable to the Tier 2 units, which is calculated as $87.132 million in Exhibit AB-33, page 2.
[245] 7 Tr 2911-2912.

Mr. Gorman testified that ABATE's proposed amortization of excess ADIT is calculated as the amount needed to offset accelerated depreciation expense for Belle River through 2030, and the amount needed to offset the accelerated depreciation expense for the Tier 2 units and recover the pre-in-service costs for the new gas plant over a 5-year period.[246]

Mr. Gorman also opined that the accelerated amortization of excess ADIT would not have a negative impact on DTE Electric's cash flows or financial integrity.[247] He also quoted a report by Moody's Investor Service noting that some state commissions have allowed tax reform relief to offset hurricane-related power restoration costs as well as early plant retirements.[248]

In rebuttal testimony, Mr. Bieber testified that he supported the plan, conditioned on a cost allocation of the excess ADIT amortization to choice customers as well as full service customers.[249] He explained:

> All classes of customers have contributed to the excess ADIT balance, including bundled customers and Choice Customers. Bundled customers have paid for the costs of generation assets and therefore have funded the excess ADIT balance that is associated with generation assets. However, bundled customers and Choice Customers both have paid the costs for distribution assets and therefore both groups of customers have funded the excess ADIT balance associated with those distribution assets.[250]

Mr. Stanczak and Mr. Solomon testified in opposition to the proposal. The principal basis of their objection was a concern the proposal would have a significant adverse effect on the utility's credit metrics. Mr. Solomon testified that proposal would result in a $172 million reduction in the company's FFO, and also increase the company's long-term debt.

[246] 7 Tr 1915-1916.
[247] 7 Tr 2916.
[248] 7 Tr 2917.
[249] 7 Tr 2746-2753.
[250] 7 Tr 2751.

He estimated the impact on the company's FFO-to-debt ratio, a key credit metric, would be a reduction of 5% when combined with the cash flow reduction from the TCJA.[251] Mr. Solomon also expressed a concern that the short-term rate reductions would have a negative long-term effect on customers as increased debt and equity in the ratemaking capital structure and potentially higher interest costs would lead to higher rates after the first five years of the plan.[252] Mr. Stanczak relied on Mr. Solomon's testimony in expressing the same concern.[253]

It its brief, ABATE urges the Commission to adopt its plan. ABATE reproduces Table 2 in its brief, contending that if DTE Electric's proposed ADIT amortization were viewed as an offset to the increased cost associated with the early retirements and new plant, it would leave a net increase in the cost of service of $120.1 million, while ABATE's plan would result in a net decrease in the cost of service of $50.8 million, a $171.6 million difference.[254] ABATE offers as an alternative an ADIT amortization smaller than its proposal as shown in Table 2, that would be just sufficient to offset the cost increases attributable to the retirements and new plant.[255] ABATE also takes issue with DTE Electric's cash flow concern. It argues that Mr. Gorman showed that the net impact on the company's cash flow would be zero,[256] and then argues that its plan is "largely cash flow neutral" to DTE Electric because its proposed recovery of the retiring and new plant costs will increase its cash flow.[257] ABATE also objects that DTE Electric did not present

[251] 5 Tr 1064.
[252] Id. at 1064-1065.
[253] 3 Tr 105-106.
[254] ABATE's initial brief, p. 17.
[255] Id. at 18.
[256] Id. at 19.
[257] Id. at 20.

a measurement of its cash flow or FFO-to-debt ratio using its projected test year cost of service, but relied only on 2017 cash flow data.[258] ABATE also cited Mr. Walters's testimony to show that DTE Electric currently has a "very strong" FFO and argues "a modest decrease to the enhanced FFO under DTE's filing will not impair its ability to maintain its investment [grade] bond rating metrics."[259] ABATE further contends that DTE Electric's rebuttal analysis ignored other financial benefits of ABATE's regulatory plan, arguing based on Mr. Gorman's testimony that the plan will strengthen DTE Electric's balance sheet and improve its cash flow coverage of debt, and arguing that the reduced cost of service will benefit ratepayers.[260]

Kroger supports ABATE's regulatory plan in its initial brief, to the extent explained by Mr. Bieber in his testimony.[261] MEC/NRDC/SC also offer conditional support for the plan in their reply brief, based on an allocation of the excess ADIT amortization amounts proportionally to the allocation of rate base to customer classes. MEC/NRDC/SC "find ABATE's proposal to be protective of ratepayers and not unduly harmful to DTE."[262] They agree with ABATE that DTE Electric's cash flow concern is unpersuasive because its analysis is not based on the rate case projections but on 2017 values.[263] MEC/NRDC/SC also discuss the potential allocation issues in greater detail.[264]

In its reply brief, DTE Electric argues that Commission should adopt the ADIT amortization proposed by DTE Electric. It cites Mr. Stanczak's and Mr. Solomon's

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[258] ABATE's initial brief, pp. 21-22, 23-25.
[259] Id. at 22.
[260] Id. at 23.
[261] Kroger's initial brief, pp. 10-12.
[262] MEC/NRDC/SC's reply brief, p. 45.
[263] Id. at 44-45.
[264] Id. at 45-46.

testimony in support of its claim that ABATE's proposal could harm the company and its customers by negatively impacting cash flows and potentially the company's credit ratings, leading to higher financing costs and potentially interfering with the company's ability to service its customers and maintain the integrity of its distribution system and generating assets.[265]

As a preliminary matter, the ALJ first finds that ABATE's Table 2 contains an error overstating the cost of service associated with the accelerated depreciation of the Tier 2 units. Table 2 reports an incremental accelerated depreciation expense of $121,568,000 for the Tier 2 units, based on Mr. Gorman's Exhibit A-33, page 2. Mr. Gorman's Exhibit A-33, page 2, however, shows $121,568,000 as the total revised depreciation expense, and shows $87,132,000 as the incremental expense over current rates. The $34,436,000 difference means the total cost of service under DTE Electric's proposal on line 5 of Exhibit AB-33 should be $86,343,000 and the total cost of service under ABATE's proposal should be ($85,257,000). Thus, ABATE's proposed amortization appears to go significantly beyond offsetting the increases associated with the accelerated plant depreciation and new plant costs.

Nonetheless, the ALJ finds the concept underlying ABATE's proposal has merit, and should be studied further in DTE Electric's next rate case. Thus, the ALJ recommends that the Commission require DTE Electric to present an analysis of the excess ADIT amortization required to offset the increased depreciation expense associated with the early retirements as well as the revenue requirement associated with the Blue Water Energy Center, including an analysis of the impact on current and

[265] DTE Electric's reply brief, pages 70-71, 130.

proposed cash flows and FFO-to-debt ratios, and an analysis of the appropriate allocation of the additional excess ADIT amortization amount.

B. Debt Cost

The company and Staff agreed on short-term and long-term debt cost rates of 2.77% and 4.36% respectively.[266] The Attorney General also used these cost rates in his analysis. No other party objected or proposed any alternative cost rates. This PFD therefore recommends that the Commission adopt the uncontested short- and long-term debt cost rates of 2.77% and 4.36% respectively.

C. Cost of Equity

1. Return on Equity

As always, the criteria for establishing a fair rate of return for public utilities is rooted in the language of the landmark United States Supreme Court cases *Bluefield Waterworks & Improvement Co v Public Service Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923) and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair rate of return, consideration should be given to both investors and customers. The rate of return should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise. Nevertheless, the determination of what is fair or reasonable, "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the

[266] 5 Tr 1048-1052, Exhibit A-14, Schedules D2 and D3.

objective sought to be attained in its use." *Township of Meridian v City of East Lansing*, 342 Mich 734, 749; 71 NW2d 234 (1955).

In DTE Electric's previous two rate cases, the company and the parties undertook the usual discounted cash flow (DCF), capital asset pricing model (CAPM) and risk premium analyses. In the last rate case the following ranges and ROE recommendations resulted from these approaches:

Case No. U-18255						
	DTE Electric	**Staff**	**Attorney General**	**ABATE**	**PFD**	**Commission Order**
ROE Range	9 ¾ -10¾ %	8.90-9.90%	8.40-9.63%	9.10-9.60%		
ROE Recommendation	10 ½ %	9.80%	9.75%	9.35%	9.6%	10.0%
Capital Structure	51% equity	51% equity	50% equity		50% equity	50% equity

In addition, the parties provided detailed criticisms of many of the finer, if not outright esoteric, details of each other's analyses including: (1) the size range and affiliation of companies selected for the proxy group; (2) appropriate market risk premium to be applied; (3) value and evidentiary weight to be afforded the empirical CAPM (ECAPM) analysis; (4) appropriate adjustments to beta used in the CAPM and ECAPM; (5) single stage versus multistage DCF models; (6) annualized versus quarterly dividend yields in the DCF model; (7) appropriate growth rate estimates from various reporting services; (8) appropriate weight to give to ROEs from other jurisdictions; (9) whether the after tax weighted average cost of capital (ATWACC) adjustment proposed by the company should be applied; (10) the financial interplay between equity ratio and ROE;

and (11) adjustment to ROE based on the inclusion of CWIP in rate base, among other things.[267]

In the instant case, it is particularly striking that the resulting ROE ranges and recommendations are virtually identical to those in the company's previous rate case:

Case No. U-20162						
	DTE Electric	**Staff**	**Attorney General**	**ABATE**		
ROE Range	9 ¾ -10¾ %	9.00-10.00%	8.47-9.25%	9.00-9.60%		
ROE Recommendation	10 ½ %	9.80%	9.50%	9.30%		
Capital Structure	51% equity	51% equity	50% equity	50%		

Ordinarily, this section would provide a detailed review of the various models, inputs, analyses and recommendations of DTE Electric, the Staff, the Attorney General, and ABATE, along with the numerous, often-repeated critiques of the modeling approaches.[268] However, given how close the results and recommendations are in this case compared to those in the company's previous rate case, coupled with the short time that has elapsed since DTE Electric's ROE was last determined, an exhaustive rehash of these issues is simply not warranted.[269] Instead, as the Commission has noted, "it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions."[270] Thus, this PFD finds the determination to be made is whether

[267] See, e.g., Case No. U-18255, PFD issued January 26, 2018, pp. 85-137. See also, Case No. U-18014, PFD issued November 21, 2016 pp. 155-198. These issues have been discussed and addressed, in some cases explicitly, by the Commission in the company's previous two rate cases.
[268] The criticisms in this case closely mirror those that were presented in the company's previous rate case.
[269] In the past, the Commission has found that, "the determination of a company's authorized ROE should be made in each case and does not require a showing that there is a compelling reason to adjust the ROE authorized in the previous rate case." January 11, 2010 order in Case No. U-15751. However, that order was issued shortly after the recession in 2008, at a time when utilities were not necessarily filing rate cases every year, as has become the practice now.
[270] March 29, 2018 order in Case No. U-18322, p. 44, which, *inter alia*, authorized an ROE of 10% for Consumers Electric.

"underlying economic conditions" have changed sufficiently since April 18, 2018, to justify DTE Electric's recommended 10.5% ROE or, conversely, to justify the 20, 25 or 65 basis point reduction in ROE recommended by the Staff, the Attorney General, and ABATE, respectively.

In its initial and reply briefs, DTE Electric highlights: (1) uncertainty in the capital markets; (2) the more challenging Michigan economic environment; (3) the relatively higher financial risk of DTE Electric compared to the sample companies; and (4) "the large-scale disruptive changes in the utility industry," all of which the company claims justify an increase in the company's recommended ROE. DTE Electric also cites increasing interest rates, significant uncertainty in global markets, the TCJA, the need for a "supportive" regulatory environment, the company's unique risk factors including significant dependence on the automobile industry and the shifting and declining population in the company's Southeast Michigan service territory. Except for the possible effects of the TCJA, which was addressed above, all of these factors were present 11 months ago and were recognized by the Commission:

> 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* and *Hope*. The Commission is confident that a 10.00% ROE satisfies the criteria in *Bluefield* and *Hope* in that it is not so high as to place an unnecessary burden on ratepayers, but high enough to ensure investor confidence in the financial soundness of the business. Finally, the Commission is confident that this ROE is appropriate given the company's known capital expenditures.
>
> As in the March 29, 2018 order in Case No. U-18322, the Commission notes 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. Noting increased volatility in global capital markets and uncertainty from the Federal Reserve Bank, DTE Electric's witness testified:

> These actions reflect increased uncertainty about the outlook for Eurozone economies, and Brexit may very likely exacerbate the problems. The low interest rate outlook for European and Japanese markets—coupled with the volatility and uncertainty that investors face in global capital markets—are driving bond investors to seek potential upside in the U.S. debt market, pushing yields down.

> 8 Tr 1413. Discussing DTE Electric's specific risks, he further states, "To the extent these forces make the Company more sensitive to volatility in the broader economy they could increase DTE Electric's systematic business risk and thus its cost of capital." 8 Tr 1428.

> That said, the Commission disagrees that the 10.5% ROE requested by the company is appropriate. In setting the ROE at 10.0%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the Commission's belief that customers do not benefit simply from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner. The fact that other utilities have been able to access capital using lower ROEs, as argued by many intervenors, is a relevant consideration. It is also important to consider how extreme market reactions to singular events, as has occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission 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.[271]

On the other hand, ABATE's recommendation to reduce the company's ROE by 65 basis points, and the Attorney General's recommended reduction from 10.0% to 9.50%, must also be rejected. Although economic circumstances have improved in the company's service territory, things have not changed so much in the past 11 months to justify a significant downward adjustment. The Staff's recommendation in this case is identical to its recommendation in the company's last rate case. However, the

[271] April 18, 2018 order in Case No. 18255, pp. 32-33.

Commission declined to adopt even the modest ROE reduction the Staff proposed in that proceeding, and it is unlikely to do so here.

Absent sufficient evidence to demonstrate that underlying economic conditions have changed significantly in the past year, this PFD finds that DTE Electric's ROE should remain at 10.0% as was set in the company's previous rate case.

2. Other Cost of Capital Issues (Performance Based Ratemaking)

Mr. Laruwe testified that, in light of the financial and regulatory impacts of performance-based ratemaking[272] (PBR) "the foundation for PBR is most appropriately developed outside of the context of the general rate case and should include open and transparent discussions with all energy stakeholders."[273]

Mr. Jester similarly testified that the Commission should consider DTE Electric's comparative performance on a wide range of issues, including affordability, reliability and service quality, pollution emissions, and low-income metrics in determining incentives and disincentives for changes in the company's performance. Mr. Jester added that PBR should not only be applied to consideration of the company's ROE, but also to the company's incentive compensation plan.[274] Mr. Jester cautioned, however:

> Because a specific system of evaluating relative performance of a utility should be done with care and broad stakeholder involvement, I do not recommend making this change in practices in the present case. Rather, in this case, the Commission should initiate a stakeholder process following on from its preparation of the PBR Report to facilitate its adoption of such criteria in the Company's next general rate case.[275]

[272] MCL 460.6u(1) defines performance based ratemaking a regulatory system in which a "utility's authorized rate of return would depend on the utility achieving targeted policy outcomes."
[273] 8 Tr 4164.
[274] 6 Tr 2164-2165.
[275] 6 Tr 2162.

In rebuttal, Mr. Stanczak testified that because any PBR mechanism would have a profound effect on DTE Electric, its system, and its customers, "[a] review of PBR is more appropriate within a general rate case proceeding, where both the measures/metrics associated with PBR and the Company's planned investments can be reviewed in tandem. Although the Company could be supportive of a collaborative for a narrow group of interested stakeholders to review the theoretical concepts of PBR and implications for Michigan, it would be impractical and inefficient to develop the foundations and standards of PBR in such a forum."[276]

Because no party provided sufficient detail on the implementation of PBR in this proceeding, the topic is not discussed in great detail in this PFD. Nevertheless, the ALJ agrees with Mr. Laruwe and Mr. Jester that the outlines of a PBR mechanism should be developed as part of a stakeholder process and then actual incentives or disincentives could be applied in a subsequent rate case. The ALJ has concerns that adding PBR to a rate case proceeding, without significant development and refinement of the mechanism outside the proceeding, could risk turning that rate case into a PBR case. Again, given the short time frame available for the parties to address the multitude of cost, rate design, and tariff issues already presented in these cases, adding a major, and likely controversial subject to the mix, would not serve the public interest.

D. Overall Rate of Return

Based on previous discussion, this PFD recommends that the Commission retain a 50/50 debt to equity capital structure, a long-term debt cost rate of 4.36%, an ROE of

[276] 3 Tr 100-101.

10.0%, and an overall weighted after-tax cost of capital of 5.48%, as shown in Appendix D.

VI.

ADJUSTED NET OPERATING INCOME

Net operating income (NOI) is calculated by subtracting the company's operating expenses including depreciation, taxes, and AFUDC, from the company's operating revenue. Adjusted NOI includes the ratemaking adjustments to the recorded NOI test year for projections and disallowances.

A. Sales Forecast and Revenue Projection

As DTE Electric noted in its reply brief, the company's sales forecast and revenue projection, as presented by Mr. Leuker, were not contested by any party. DTE Electric further explained that it agreed with the Staff's projected enrollment of 60,000 customers in the residential income assistance (RIA) program. Accordingly, the company's sales revenue projection, as adjusted in its reply brief, of $4.786 billion should be adopted.[277]

B. Power Supply Costs

As set forth in the testimony of Ms. Holmes, DTE Electric is not proposing to reset the PSCR base in this proceeding. Ms. Holmes explained that the PSCR base amount was set in Case No. U-15244 at 31.26 mills per kilowatt-hour (kWh), with a loss factor of

[277] Soulardarity raises concerns that the Staff's proposed 60,000 RIA enrollees operates as a cap on enrollment. It is not. The 60,000 number is a projection based on historical enrollment rates.

6.8% for a total of 33.39 mills/kWh. "Since the PSCR revenues and expenses are reconciled on an annual basis, and the maximum PSCR factor for 2018 in DTE Electric's recently filed 2018 PSCR Plan case (U-18403) is a credit of (0.087) cents/kWh, the Company does not believe it is necessary to reset the base at this time."[278]

No party objected to the company's proposal. Accordingly, DTE Electric's recommended power supply costs should be adopted.

C. Operations and Maintenance Expense

1. Inflation on Operations and Maintenance Expense

Ms. Uzenski testified that in determining test year O&M expense, DTE Electric started with 2017 actual, year-end balances that were normalized and adjusted for unusual items, and then escalated for inflation. Ms. Uzenski stated that she calculated a composite inflation factor based on labor and non-labor factors, using a labor factor of 3% for both internal and contract labor because many of the contract employees are in the same unions as company employees.[279] Ms. Uzenski testified that the increase in O&M expense from the historic period is projected to be $78.3 million, primarily due to inflation.[280]

Mr. Cooper testified that "[b]ased on existing Collective Bargaining Agreements, the Company is obligated to increase pay rates by approximately 3.0% annually through the term of the contracts." Mr. Cooper added that for non-represented employees, compensation is reviewed and adjusted annually based on compensation practices of

[278] 5 Tr 1424-1425; Exhibit A-13, Schedule C4.
[279] 7 Tr 3302; Exhibit A-13, Schedule C5.15.
[280] 7 Tr 3303; Exhibit A-13, Schedule C5.

other employers. In March 2018, Mr. Cooper testified that DTE Electric implemented a 3% base pay increase for all employees. Accordingly, Mr. Cooper determined that "annual escalations of 3.0% for 2018, 2019 and 2020 are a conservative estimate of the Company's expected increase in its labor rates."[281] Mr. Leuker testified that for 2018 and 2019, the Consumer Price Index for All Urban Consumers is forecast to increase by 2.3% in 2018, 1.7% in 2019, and 2.7% in 2020.[282]

The Staff used inflation factors of 2.52%, 2.23% and 2.50% for 2018-2020, resulting in a reduction of $12,338,000 to the company's O&M expense. In its initial brief, the Staff argued that the company had not rebutted the Staff's recommended inflation adjustments, and therefore, the Staff's inflation amounts should be adopted.

Mr. Coppola observed that the use of a blended labor/non-labor inflation factor has been rejected by the Commission in the past as inappropriate. Mr. Coppola further testified:

> More importantly, and contradicting some of the Company testimony in this case, DTEE has not experienced across-the-board inflation pressure on its operating costs. In fact, actual O&M costs have been on a declining trend in the most recent 6 years, including 2017. As the following chart shows, O&M expenses in 2017 declined further to just over $1.2 billion. Exhibit AG-1 includes the analysis from Company-provided information showing how actual costs have been below the inflation adjusted level. It is therefore difficult to understand why the Company would project inflation-related cost increases for 2018, 2019 and the four months in 2020.[283]

Mr. Coppola continued, explaining that he analyzed DTE Electric's projected O&M expense for 2017, based on the company's forecast in Case No. U-18014. According to Mr. Coppola, actual O&M expense was $112 million below the projected expense.[284] Mr.

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[281] 6 Tr 1832.
[282] 5 Tr 1479; Exhibit A-15, Schedule E-4.
[283] 5 Tr 1595-1596; Exhibit AG-1.
[284] 5 Tr 1596; Exhibit AG-3.

Coppola concluded by noting that DTE Electric provided no evidence of inflationary pressure on costs, the Commission has rejected the use of blended inflation rates, and the inclusion of projected inflation could become a "self-fulfilling prophesy."[285] Accordingly, Mr. Coppola recommended removing inflation from all O&M expenses except for healthcare, an adjustment of $75.4 million.[286]

Mr. Bieber testified that he disagreed with the inclusion of a generic inflation factor to non-labor O&M expense for two reasons: (1) from a policy standpoint, adding inflation to projected costs can make inflation a self-fulfilling prophesy; and (2) given that the company is already using projected costs, issues with regulatory lag are already addressed and an additional "cost cushion" on top of these projections is unnecessary.[287] Mr. Bieber explained further:

> The primary justification for utilizing a projected test period is to allow a utility with expanding rate base the ability to avoid regulatory lag; that is, the use of a projected test period is intended to provide a utility a better opportunity to recover its investment cost than might occur with an historical test period. By including inflation in its non-labor O&M expenses, DTE is attempting to go well beyond simply aligning the test period with its projected test year investment to mitigate regulatory lag; the Company is also attempting to gain an additional benefit by inflating its baseline costs by applying an inflation factor. DTE should not be rewarded for the use of a forecasted test period with a windfall mark-up of its baseline costs. The Commission should not allow the utilization of a forward-looking test period to also become a vehicle for utility recovery of such "pseudo costs."
>
> The best evidence of what it costs DTE for non-labor O&M is the Company's actual costs recorded in the historical period, adjusted for certain known and measurable changes. The cost increases represented by DTE's inflation assumption may or may not come to fruition. In any case, DTE should be expected to strive to improve its O&M efficiency on a continuous basis, and thereby lessen the net impact of inflation on its O&M

[285] 5 Tr 1597.
[286] Id. at 1598.
[287] 7 Tr 2739-2740.

> costs. It is not reasonable to simply gross up the Company's historical period costs by an inflation factor and pass these costs on to customers. [288]

Mr. Bieber further observed that DTE Electric did not project any O&M efficiencies that might offset inflation, and pointed to a discovery response that DTE Electric provided to ABATE so indicating.[289]

In rebuttal to the Attorney General, Mr. Stanczak testified that, "[a]lthough the Company's ability to manage O&M in the past has been exceptional, the Company cannot continually reduce non-labor O&M in order to offset wage growth." He reiterated that the company's growth in labor O&M is largely driven by collective bargaining agreements.

In rebuttal to Mr. Bieber, Ms. Uzenski contended that it is not reasonable to assume no inflation will occur, as Mr. Bieber's testimony states. She added that:

> [T]he actual amount of Mr. Bieber's adjustment regarding non-labor inflation is inaccurate. As shown on my Exhibit A-36, Schedule Z1, Mr. Bieber included inflation related to Outside Services as non-labor in deriving his $31.5 million reduction. However, the labor line in this document includes internal labor only. Contractor and consultant labor is reflected in the "Outside Services" line. Therefore, the correct amount for non-labor inflation is $5.3 million.[290]

The parties' briefs and reply brief largely rely on the testimony of their respective witnesses, with DTE Electric pointing to the known escalation in labor contracts as a significant driver of O&M increases. DTE Electric disputes the Attorney General's analysis from amounts in Case No. U-18014, noting that she simply compared the amount of O&M requested to the amount actually spent, without recognizing that the company's full rate request was not granted. DTE Electric adds that even Mr. Bieber testified that

[288] Id. at 2740-2741.
[289] This discovery response does not appear have been entered in the record as an exhibit; however, on cross examination, Ms. Uzenski confirmed that DTE Electric did not assume any efficiencies in its O&M budget for 2019 and 2020. 7 Tr 3361.
[290] 7 Tr 3344.

some inflation is expected during the bridge and test periods.

The Staff points out that the company did not rebut its proposed inflation rates, and the Attorney General again notes that the Commission has previously rejected the use of a composite inflation rate as proposed by the company. The Attorney General reiterated that the company has successfully avoided the effects of inflation on O&M for several years.

This PFD finds that the Staff's inflation rates should be applied to O&M expense. As the Attorney General points out, the use of a composite inflation rate has been rejected in the company's past two rate cases, and, as the Staff observes, the company did not rebut the Staff's position, which recognizes that some inflation is likely to occur, but that productivity increases will offset higher labor inflation rates. In future cases, the parties are encouraged to more closely scrutinize the impacts of inflation on historical O&M costs to determine the extent to which inflation is offset by productivity gains.

2. Fossil Generation

a. St. Clair Outage Normalization Adjustment

Mr. Paul testified that DTE Electric's fossil generation O&M expenses fall into three major categories: (1) steam power generation; (2) hydraulic power; and (3) other power generation. Mr. Paul testified that for 2017, steam power generation adjusted O&M was $266.0 million in 2017, and is projected to be $284.7 million in the projected test year.[291] Part of the company's calculation of 2017 steam power generation expense included adjustments for the 2017 fire and outage at St. Clair Unit 7. Referencing Exhibit A-13, Schedule C 5.1, page 1, note 4, Mr. Paul explained that there was a net $1.9 million

[291] 4 Tr 579; Exhibit A-13, Schedule C5.1, page 1.

normalizing adjustment, which included the removal of $23.1 million in costs associated with the fire and outage and:

> $3.6 million added in as a normalization change to reflect normal 2016 plant operations that were interrupted by continuing work to restore plant equipment and systems after the August 2016 St. Clair Power Plant outage event. Had the Company not been expensing $23.1million to restore the plant and plant equipment damaged in the August 2016 outage event, normal plant operations would have required funding of $3.6million.[292]

Mr. Coppola recommended a disallowance of $3.6 million related to the above described normalization adjustment. According to Mr. Coppola:

> Although Company witness Matthew Paul's testimony is devoid of an explanation for this adjustment and the footnote to the projected O&M expense in the referenced exhibit is somewhat convoluted, in response to a discovery request, the Company provided an explanation. The explanation states that the Company would have incurred an additional $3.6 million in O&M expense if the St. 15 Clair power plant explosion had not occurred. Unfortunately, the Company did not provide any additional information as to how the $3.6 million potential cost was calculated and how it will be incurred in the projected test year. If the $3.6 million represents the cost of Company labor for fire recovery work, as the discovery response indicates, it does not necessarily mean that the same time and effort would be expanded in day to day operation of the plant in the projected test year.[293]

Mr. Coppola concluded that the $3.6 million adjustment was not adequately supported and should therefore be disallowed.

In rebuttal, Mr. Paul explained that it appeared that the Attorney General misconstrued the company's discovery response, testifying:

> [T]he $3.6 million represents straight-time labor charges from plant personnel that were performing fire recovery work in 2017 and not their normal duties which they would have performed absent the fire event. In other words, the $3.6 million is the ordinary historical day-to-day expense of these DTE Electric personnel which will continue to be incurred into the

[292] 4 Tr 584.
[293] 5 Tr 1599-1600, referencing DTE Electric's response to discovery responses AGDE-2.131 and 4.256a, admitted as Exhibit A-41, Schedules EE1 and EE2.

> future now that ordinary St. Clair power plant operations have resumed. In the projected test year, because the fire recovery efforts have been completed, these same plant personnel will be spending all of their time performing normal plant operation functions, including the portion of their time that was spent on fire recovery efforts during 2017. Recovery of the $3.6 million adjustment is necessary to provide the proper amount of funding to accommodate straight-time labor associated with normal plant operations.[294]

In her brief, the Attorney General maintains that DTE Electric failed to provide a clear explanation of the $3.6 million adjustment. According to her:

> [t]he Company appears to be saying that the proposed increase in O&M costs stems from the fire event. However, Mr. Paul's rebuttal testimony also seems to imply that these costs were simply costs that were shifted to fire restoration work in the interim, and now need to be shifted back to normal operations. This would seem to indicate that no increase in O&M is necessary for this St. Clair event.[295]

In response DTE Electric reiterates that:

> [T]he $3.6 million represents straight-time labor charges from plant personnel who were performing fire recovery work instead of their normal duties in 2017.In other words, those employees would have been performing their day-to-day obligations, but since the fire disrupted those obligations, the employees were instead performing recovery work. Thus, the $3.6 million is the ordinary historical expense for DTE Electric personnel that will continue to be incurred now that normal operations have resumed at the St. Clair power plant.[296]

DTE Electric adds that it is not seeking an "increase" but is simply making a normalization adjustment that recognizes that employees were assigned to higher-priority duties during the outage event.

This PFD finds that the company quite adequately explained the normalization adjustments, which resulted in a $1.9 million net adjustment, arising from the fire and outage at the St. Clair plant. As Mr. Paul explained in his direct testimony, the $23.1

[294] 4 Tr 596.
[295] Attorney General's initial brief, p. 19 (footnotes omitted).
[296] DTE Electric's reply brief, p. 97.

million total cost of the event was removed from historical expense as non-recurring. Then, the company added back $3.6 million to reflect the normal costs, had the outage not occurred. The Attorney General's proposed disallowance is therefore rejected.

b. River Rouge Unit 3 Operations and Maintenance

As discussed above, both the capital costs, and O&M costs of $17.7 million for the test year, for RR 3 should be disallowed in this proceeding.

3. Fuel Supply and Midwest Energy Resources Company Expense

As DTE Electric points out in its reply brief, there were no objections to the company's proposed fuel supply and MERC expenses. These costs should therefore be approved.

4. Fermi 2 Expense

Mr. Davis testified that for the historical test period, adjusted nuclear O&M expenses were $143.5 million and projected nuclear O&M for the test year are $166.8 million. There were no recommended adjustments to these O&M amounts. Therefore, the company's projection should be adopted.

5. Distribution Operations Expense

Ms. Rivard provided an overview of DTE Electric's enhanced tree-trimming program (ETTP), noting that the ETTP was also described in detail in the company's last two rate cases.[297] Ms. Rivard testified that in 2017, DTE Electric trimmed 3,601 miles on 305 separate circuits, compared to a plan of 3,618 miles. The company also spent $84.3 million for ETTP work, $9.1 million more than the $75.2 million approved in Case No. U-

[297] "Enhanced" tree trimming refers to expanded tree and branch removal practices that clear all vegetation that could overgrow DTE Electric's lines in five years.

18014. With respect to reliability, Ms. Rivard reported that the number of customer interruptions was reduced by about 50%, and the number of minutes of interruption was reduced by 80% in the circuits that were trimmed as part of the ETTP compared to circuits that were trimmed conventionally.[298] Ms. Rivard further indicated that even in the major storm event in May 2017, the ETTP trimmed circuits performed significantly better than the company's other circuits.[299]

Ms. Rivard testified that the company plans to trim 3,978 miles in 2018, and she provided an overview of measures the company has undertaken to increase ETTP contractor productivity[300] Referencing testimony by Mr. Bruzzano, Ms. Rivard reiterated that DTE Electric is in the bottom quartile of the electric industry based on SAIDI excluding MEDs. Ms. Rivard further explained that tree interference causes two thirds of customer outages and that the means to address this problem is a robust tree-trimming program. Ms. Rivard testified that DTE Electric is currently on an eight to nine year tree trimming cycle, which the company wants to reduce to a five-year trimming cycle. In order to arrive at this goal, DTE Electric needs to trim about 6,500 miles per year.[301]

To arrive at its five-year tree-trimming objective, DTE Electric proposed a seven-year tree-trimming "surge" that will allow the company to address the three to four year backlog of untrimmed circuits while at the same time maintaining the ETTP circuits at a five-year trimming interval.[302]

[298] 3 Tr 200-201.
[299] Id. at 204.
[300] Id. 205-206.
[301] 3 Tr 207-208.
[302] Id. 211-212.

Ms. Rivard testified that reducing the tree-trimming cycle to five years will result in numerous customer benefits including fewer complaints and wire down events, fewer outages with lower reactive O&M costs, and lower tree-trimming costs in the future. Ms. Rivard estimated that the NPV of the tree trimming surge, compared to current practice, is $67 million.[303] Upon completion of the program in seven years, DTE Electric anticipates a 40% reduction in tree-related outage events and a 40% reduction in tree-related SAIDI.[304]

Ms. Rivard provided an overview of historic and projected tree-trimming expenses for the ETTP, noting that the company is projecting O&M expense of $95.1 million for the test year, including inflation, maintenance and staff, and herbicides.[305] In addition to this base O&M expense amount, Ms. Rivard testified that DTE Electric is requesting $43.3 million and $74.1 million for 2019 and 2020 of addition funding for the tree-trimming surge.[306] These additional amounts will be deferred as a regulatory asset and amortized over 14 years. The regulatory asset will then be securitized.

Ms. Rivard testified that the total cost of the tree-trimming program from 2019-2025 is $1.13 billion, with $722 million recovered through base utility rates and $410 million through the alternative mechanism.[307] Ms. Rivard estimated a cost of $20,160 per mile for ETTP backlog trimming, with a reduction of 40% in cost to trim in areas that have already been trimmed to ETTP standards.[308]

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[303] 3 Tr 216; Exhibit A-22 Schedule L1 (Revised). Ms. Rivard noted that the NPV analysis only looked at revenue requirement through 2040, and did not factor in other economic benefits from the program.
[304] 3 Tr 217-218.
[305] 3 Tr 223; Exhibit A-13, Schedule C5.6, p. 3.
[306] 3 Tr 226; Exhibit A-22, Schedule L1 (Revised), line 11.
[307] 3 Tr 234
[308] Id. at 228.

With respect to resources for the program, Ms. Rivard testified that approximately 1,300 tree trimmers will be required to implement the program by 2022, 450 more than currently work for DTE Electric. Given the size of the program, DTE Electric will not be able to rely solely on local crews and will have to contract with crews from outside the company's service territory. Ms. Rivard indicated that the company is partnering with a local union to increase local staffing resources for the program.[309] Ms. Rivard also described the herbicide program, noting that the brush control effort is expected to decrease overall tree-trimming costs by 3%.[310] Finally, Ms. Rivard testified that DTE Electric proposes to provide annual reports to the Commission on ETTP circuit performance comparing average outages for three years prior to the enhanced trimming along with outages in the year after the trimming is performed. In addition, DTE Electric will submit a Tree Trimming Effectiveness Report in 2022.

Ms. Uzenski testified that DTE Electric is requesting regulatory asset treatment for excess ETTP costs, deferring the costs of the surge program in account 182.3, Other Regulatory Assets, "and to amortize each vintage year balance over a 14-year period to be consistent with the maximum bond term discussed by Witness Solomon." The deferred costs of $43.3 million for the first year of the program divided by 14 years equals approximately $3.1 million per year in amortization costs.[311]

Mr. Solomon testified that prior to securitization, the regulatory asset for the tree trimming surge will be financed consistent with the company's capital structure. Once the regulatory asset balance reaches $100 million, DTE Electric intends to securitize the

[309] 3 Tr 237-238.
[310] 3 Tr 238-242.
[311] 7 Tr 3336; Exhibit A-22, Schedule L3.

asset. This securitization of the regulatory asset is expected to occur every other year.[312]

Mr. Solomon explained that securitization will benefit ratepayers:

> [S]ince the net present value (NPV) of the estimated revenue requirements collected under the intended securitization financing orders will be less than the NPV of the estimated revenue requirements that would be recovered over the remaining life of the qualified costs using conventional financing. These benefits from intended securitizations are due to the fact that the interest rate on the intended securitization bonds is expected to be less than the pre-tax cost of capital of 6.63% used in the Company's rates based on conventional financing.[313]

Mr. Solomon admitted, however that "[t]he precise terms and conditions of the Intended Securitization will not be known until just prior to the time of sale, which is anticipated to take place around Q4 2020 for the first bond."[314]

Mr. Evans testified that although the additional cost of the tree trimming surge is $410 million, because of the company's proposed regulatory asset treatment, the costs could be as high as $600 million due to the return on the deferral of costs over $95 million. Securitization could reduce this cost some, but ratepayers would still be paying an O&M expense over 14 years rather than as the cost is incurred.

Mr. Evans stated that the Staff supports the company's objective to reach a five-year tree trimming cycle for distribution circuits, as well as a three-year cycle for sub-transmission, noting that DTE Electric will require additional funding over time to address the backlog of trees that are not trimmed to ETTP standards. However, given the additional cost associated with amortization, Mr. Evans opined that DTE Electric's proposed deferral is not in the best interest of ratepayers.[315]

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[312] 5 Tr 1053-1054.
[313] Id at 1055.
[314] Id. at 1056.
[315] 8 Tr 4127-4128.

As an alternative to DTE Electric's proposal, Mr. Evans recommended that the Commission disallow the $7,053,000 revenue requirement associated with deferred ETTP costs and instead increase the O&M expense amount for tree trimming from $95,092,000 to $108,099,000. Mr. Evans explained that in subsequent rate cases, the company may request additional O&M for the ETTP, until the backlog is cleared. At that time, the company could reduce its O&M amount to that shown in Exhibit A-22, Schedule L1. "This would allow tree trim O&M expense embedded in rates to increase gradually and make the Surge more affordable in the short term."[316]

In rebuttal, Ms. Rivard testified that although DTE Electric is pleased with the Staff's general support of the ETTP, Mr. Evans' recommendation will take 8 years and four months to clear the ETTP backlog, rather than seven years under the company's surge proposal.[317] Ms. Rivard further opined that the company's proposal has several advantages including: (1) the company's proposal will allow the company to more quickly reduce the backlog of circuits that are not trimmed to ETTP specifications; (2) the surge proposal will result in lower short-term rate increases because costs are amortized over a 14-year period, allowing future costs to match future benefits; and (3) the assurance of funding, assuming the company's proposal is adopted, will allow DTE Electric to enter into long-term contracts with tree-trimmers who are in high demand across the country.[318]

Nevertheless, if the Staff's proposal is adopted, Ms. Rivard recommended that the Commission approve $137.5 million tree trimming O&M for the test year, noting that this would be a reasonable compromise.

[316] 8 Tr 4129; Exhibit S-10.5.
[317] 3 Tr 247.
[318] Id. at 248-249.

Mr. Coppola testified that he supported the tree trimming program proposed by DTE Electric, but he also recommended that the company be held accountable for the results of the program by meeting certain interim goals. Specifically, Mr. Coppola proposed:

> 1. The Commission should set the number of forecasted outages as target levels for the Company to achieve for each year 2019 to 2030. The target levels are reflected under the Surge Program in the Company workpaper HDR-1 shown in Exhibit AG-9[.]
>
> 2. The Company should provide a report to the Commission in early 2022 reviewing the spending, accomplishments and, most importantly, the effectiveness in reducing the number of tree-related outages against the targets during the first three years of the program. The three-year time frame would be sufficiently long to show any improvements. This review and report should reoccur annually thereafter for the entirety of the program.
>
> 3. If the Company achieves at least 80% of the target reductions in outages, the Commission should affirm continuation of the program.
>
> 4. If the Company fails to achieve at least 80% of the average reductions in the target levels versus the Status Quo levels shown in workpaper HDR24 1 for the 2019 to 2021 period, and subsequent cumulative periods, then the Company will forfeit recovery of 1% of the deferred expense for those years for each percent it falls short of the 80% level.
>
> 5. If the Company fails to achieve any reduction or the number of outages increases over the Status Quo level during 2019 to 2021, or cumulative subsequent periods, then the Company will forfeit 100% of any remaining balance in the deferred regulatory asset.
>
> 6. If the Company fails to achieve at least 50% of the target outage reductions over the review period, the Commission should set a new spending level that the Company can recover in future years and warn the Company that any amounts exceeding the approved level are not likely to be recovered in rates in future years unless the program is able to achieve at least 80% of the target reductions.[319]

In rebuttal, Ms. Rivard pointed out that the company is only requesting deferral for a short period and that, as discussed by Mr. Solomon, DTE Electric intends to securitize

[319] 5 Tr 1604-1605.

the regulatory asset when the balance reaches $100 million in late 2020. At that point, ratepayers will only pay the cost of the debt and there will be no additional return to shareholders. Ms. Rivard also testified that Mr. Coppola's proposal to base performance on yearly outage metrics does not account for severe weather, such as the storm in May 2017. And Ms. Rivard stated that the company is not able to fully predict the market for tree-trimmers, noting that the recent wildfires in California has led to an increase in tree trimming budgets which has in turn caused the already tight labor market for tree trimmers to tighten further.[320]

Mr. Jester recommended that "the Commission minimize other distribution system expenditures and require the Company to accelerate tree-trimming programs using enhanced tree-trimming practices to the most rapid pace that can be efficiently and properly executed."[321] Nevertheless, Mr. Jester testified that tree trimming costs have increased in the past because DTE Electric failed to keep up with an appropriate tree trimming cycle. According to Mr. Jester,

> Having paid these extra costs for many years, it is unreasonable that customers should now pay for all of the costs of putting tree-trimming back onto the appropriate cycle. The Commission could rectify this history by authorizing the regulatory asset for the "tree-trimming surge" but reducing the amount of the regulatory asset by an amount that reflects the present value of the Company's historical failure to trim trees on a reasonable schedule.[322]

In rebuttal, Ms. Rivard pointed out that the company maintained a 5-year trimming cycle under industry standard specifications until 2013. In 2014, DTE Electric implemented the ETTP, which required more extensive tree trimming and was more

[320] 3 Tr 250-251.
[321] 6 Tr 2180.
[322] 6 Tr 2182.

costly. Ms. Rivard also provided data that showed that except for 2009 and 2014, the company spent more than the amount of tree trimming O&M expense approved by the Commission.[323]

The parties' briefs generally rely on their respective witness's testimony. The RCG recommends that the Commission reject the deferral and amortization proposed by the company, and adopt a tracker with actual tree-trimming costs reconciled periodically.

In its reply brief, DTE Electric reiterates that, "[n]o other program in the Company's portfolio of distribution projects will have a greater impact on mitigating risks, improving system and customer reliability, and managing the costs of operating the Company's distribution system."[324] DTE Electric adds that because the benefits of enhanced tree trimming are expected to continue for years after the trees are trimmed to the ETTP specification; thus, deferral and amortization will better match the costs with the benefits of the program. If the Commission does not approve the company's proposal as set out by Ms. Rivard, DTE Electric recommends that the Commission approve the deferral and determine the appropriate amortization period in a later rate case or increase the tree trimming O&M expense amount to $137 million in this case.[325] DTE Electric also opposes the RCG's recommended tracker, noting that actual tree-trimming costs have exceeded approved costs for several years, and the company expects that to continue.[326]

In its reply brief, the Staff urges the Commission to reject the company's alternative proposals, adding that by the Staff's calculation, ratepayers would still be better off paying tree-trimming costs as part of O&M. The Staff urges the Commission to pay particular

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[323] 3 Tr 252-253.
[324] DTE Electric's reply brief, p. 99.
[325] Id. at 101.
[326] Id. at 105.

attention to Ms. Rivard's rebuttal testimony regarding the effect on the tree-trimming labor market of the recent wildfires in California. According to the Staff, "the Commission should consider the possibility that the Company may not be able to secure enough tree trimmers over the next couple years to execute its surge plan as proposed."[327]

This PFD recommends that the Staff's proposal, to remove the amortization cost from the company's rate request and increase tree trimming O&M expense from $95.1 million to $108.1 million is most reasonable and should be adopted. As the Staff, the Attorney General, and MEC/NRDC/SC point out, the proposed deferral and amortization of tree trimming costs could result in $200 million more in revenue requirement to cover the cost of the program. Granted, securitization of these excess costs would reduce the amount that would need to be recovered in the future, but the terms and conditions of the proposed securitization are not known at this time, as Mr. Solomon admitted.

The company's proposed compromise, requesting an increase to $137 million, from the Staff's proposed $108.1 million, in tree trimming O&M expense should be rejected, largely on the grounds that the Staff argues: namely that $137 million would be a 64% increase in the tree-trimming budget at a time when there is significant uncertainty about the availability of tree-trimming labor in light of recent disasters.

While this PFD makes no recommendation on the implementation of a tracker, the 27% increase in tree-trimming O&M (from $85 million to $108 million) merits the Commission's consideration. A two-way tracker would protect the company in the event of overspending, and it would also protect customers in the event that the company is

[327] Staff's reply brief, p. 6-7.

unable to secure sufficient resources for the program, as highlighted in Ms. Rivard's testimony.

With respect to reporting metrics, this PFD agrees with DTE Electric that the Attorney General's reporting requirements and possible penalties are not reasonable to impose at this time. As the company points out, the Attorney General's proposal fails to take into account outages due to significant storms, and it fails to consider the unpredictability of labor availability, which could affect the scope of the program in the initial years. In briefing, MEC/NRDC/SC did not address Ms. Rivard's rebuttal to the recommendation to reduce cost recovery based on alleged underspending in prior periods. This recommendation should therefore be rejected.

6. Community Lighting Expense

As DTE Electric noted in its brief, there were no issues raised with respect to the company's proposed community lighting expense. Ms. Zhou testified that street lighting and traffic signal expense remain at the 2017 level, and that the $3.2 amount for the projected test period includes inflation and a light emitting diode washing program. Except for inflation, discussed above, the company's community lighting expense for the test period should be approved.

7. Customer Service and Marketing

a. Meter Reading

Ms. Johnson testified that the customer accounts expense category includes customer records and collection, customer records and collection-merchant fees, and meter reading expense. Ms. Johnson explained that the $3.4 million in meter reading expense covered the cost of external vendors to manually read meters that are not AMI meters or that are part of the opt-out program. "Other activities include billing operations pertaining to major accounts, metering operations, consecutive estimate team and special reading expenses."[328]

Mr. Matthews testified that $2.147 million in meter reading expenses should be disallowed. Mr. Matthews explained:

> [I]t is inappropriate to use 2017 as a base year and inflate it to make the projection from[,] as the Company has continued to install and reduce the amount of manual meter reading it must perform. With the installation of AMI meters since 2017, the number of meter reading employees the Company had in the 2017 historical period was 58, while the number projected in the test period is 24, as shown in Staff Exhibit S-12.3, page 13.[329]

In rebuttal, Ms. Johnson explained that the Staff's calculation was incorrect because, as was explained in her direct testimony, meter reading expense comprises more than just the cost of external vendors to manually read meters, and the Staff's calculation does not include these additional costs.[330]

In its initial brief, the Staff contended that the company's projection for meter-reading expense does not include the reduced number of meter readers required to manually read non-AMI meters, noting, "[t]he projected meter reading expenses of $3,630,000 is based on historical spending, at a time when the Company employed substantially more meter readers than it does today. It is imprudent to base test-year meter-reading costs on the 2017 historical year."[331] The Staff further pointed out that:

> The Company has named other expenses that have fallen into the category of meter reading expenses but gives no information about the costs

[328] 7 Tr 3113; Exhibit A-13, Schedule C5.7.
[329] 8 Tr 4153.
[330] 7 Tr 3140.
[331] Staff's initial brief, p. 70.

> associated with each of the other categories. It is Staff's assumption that the majority of the expenses in a category called meter reading expenses would be actual meter reading. The Company has not provided enough information about the other expenses in the meter reading category to justify not including the savings that the AMI program has had on this category.[332]

This PFD agrees that the Staff's proposed adjustment is appropriate. Despite a substantial reduction in the number of manual meter readers the company employs, DTE Electric nevertheless failed to reflect that reduction in its O&M projection. Instead, the company simply used the 2017 amount and inflated it to arrive at a projected amount. DTE Electric failed to provide the breakdown of costs in the meter reading category into those that involve meter reading personnel and other meter reading costs. The Staff's assumption that meter reading costs are largely comprised of contract personnel was a reasonable one. The PFD recommends that the Staff's adjustment to meter reading O&M be adopted.

b. Merchant Fees

Ms. Johnson testified that DTE Electric was proposing a $2.6 million increase for merchant fees to cover the increased cost of credit card processing, as more customers are using credit cards for bill payment. According to Ms. Johnson, the company is proposing a $0.9 million increase for residential merchant fees and $1.8 million increase for merchant fees for non-residential customer accounts on rates D3, D4, and D5. Ms. Johnson noted that "the number of non-residential customers using credit cards, and the cost per transaction have grown exponentially over the past five years. Aggressive marketing campaigns and incentive programs by banks and credit card companies have

[332] Id. at 71.

targeted non-residential customers by incentivizing them with cash back rewards when using credit cards."[333] As a result, "the Company has experienced a year-over-year increase of 90% and a five-year compound annual growth rate of 60% in merchant fees for corporate credit cards."[334]

Mr. Coppola testified that while he agreed a credit card payment program for residential customers was justified by increased customer convenience and reduced uncollectibles, the same rationale does not necessarily apply to small commercial customers. Mr. Coppola testified that the $1.8 million increase for the non-residential program should not be approved. In addition, Mr. Coppola recommended that the expense level for the non-residential credit card program be set at $1.6 million, or half the 2017 historical expense level.[335]

According to Mr. Coppola:

> DTEE currently pays, on average, 6.7% in fees on electric bills paid by credit cards. The Company should be granted permission to charge a 3% fee to businesses paying by credit card which in turn will minimize the Company's cost. Non-residential customers, who are primarily small to medium size commercial customers, tend to have much larger bills which can add to significant credit card fees for the Company. Splitting the credit card fees between the Company and this group of customers is a reasonable change to the program to avoid ever-increasing card fees for the rest of the customer base to absorb.[336]

In rebuttal testimony, Ms. Johnson explained that splitting merchant fees between the company and its non-residential customers could result in customer dissatisfaction and an increase in uncollectibles. She also disputed Mr. Coppola's claim that DTE Electric pays fees of 6.7% on bills paid by credit card, testifying that for non-residential

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[333] 7 Tr 3121
[334] Id.
[335] 5 Tr 1607.
[336] Id. at 1607-1708.

customers, the fees are approximately 2% of sales, and for residential customers merchant fees are approximately 0.7% of residential sales.[337]

The ALJ agrees with DTE Electric that merchant fees for small commercial customers are reasonably included in the company's O&M expense. As the company explained, payment by credit card is an increasingly popular option for both residential customers and small commercial customers, and the convenience of this payment option, coupled with reduced uncollectibles, appears to outweigh the fairly minor cost.

8. Uncollectibles Expense

a. Calculation of Uncollectibles Expense

Ms. Johnson presented DTE's projected uncollectible expense of $51.6 million based on the use of a three-year average of actual uncollectible expense for 2015 through 2017. She testified that the projected amount reflects the company's planned efforts to sustain its improved collection despite continuing economic challenges for many of its customers.[338]

Mr. Welke proposed that a cash-basis method, using the 2015-2017 three-year average of the ratio of net charge offs to revenue, be utilized to project uncollectibles expense for the test period. He applied the resulting percentages to the present revenues in the projected test period to arrive at an estimate of $51.4 million as shown on Staff's Exhibit S-3, Schedule C5.1.

Mr. Welke acknowledged that in the last three DTE Electric rate cases, the uncollectible accounts expense has either been based on three-year averages based on an accrual basis of accounting or the most recent historical year experience. However,

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[337] 7 Tr 3143.

[338] 7 Tr 3122; Exhibit A-13, Schedule C5.7 p. 1, line 22 and page 2.

he notes that the Commission has not utilized this method in orders that relate to other companies. Specifically, in Case No. U-17990, "The Commission [was] persuaded that the average of the ratio of net charge offs to revenue for the 2011 to 2015 period, as offered by the Attorney General and accepted by the Staff, is the more reasonable methodology." This method has been utilized in numerous Commission orders. He testified that this methodology is known as the cash-basis method of projecting uncollectible accounts expense. Staff believes that this is a better approach that provides a reasonable estimate of future uncollectible accounts expense. Further, it mitigates the potential for forecasting error and high period over period volatility.[339]

Ms. Uzenski disputed this method, contending that it is flawed because there is no direct correlation of the net charge-offs and revenues used to calculate the ratio in any given year. In addition, there is a significant timing lag between revenue recognition and when the net charge-offs occur. She testified that DTE Electric uses a balance sheet method to accrue a reserve for the estimate portion of customer accounts receivable that will ultimately be written off[340].

The Staff contends that the cash basis method multiplies an average of actual net write-offs to a projected level of sales, and it is grounded in actual experience. The three-year average of the accrual basis used by DTE Electric relies on accounting estimates that involve assumptions that could result in a significant forecasting error. The cash basis is a better approach because it mitigates this potential for forecasting error. Further, this

[339] 8 Tr 4026-4029.
[340] 7 Tr 3345-3346.

method has been adopted by the Commission in Case Nos. U-14347, U-16191, U-16794, U-17735 and U-17990.[341]

DTE Electric argues that the cash basis method is flawed. Additionally, the company contends that there is a significant time lag between revenue recognition and when the net charge offs occur. The Company uses a balance sheet method to accrue a reserve for the estimated portion of the customer accounts receivable that will ultimately be written off. The uncollectible expense recorded in the income statement reflects the change in the balance sheet reserve need to reflect accounts receivable as a net realizable amount.

DTE Electric argues that, despite the Staff's claim that the company's assumptions could result in a significant forecasting error, the reduction proposed would only be a $234,000. Furthermore, the company indicates that the historical period uncollectible expense has been approved by the Commission in past rates cases for both DTE Electric and DTE Gas in Case Nos. U-18255 and U-18014, U-18999 and U-17999.[342]

This PFD recommends that the Commission adopt the cash basis method as recommended by the Staff. This method has been approved by the Commission in a number of previous rate cases involving other utilities and it is important to have consistency in the method utilized to determine uncollectible expense across the industry rather than utilizing different methods for each utility company. In addition, the Staff's method appears more accurate and less prone to potentially significant forecasting error.

[341] Staff's initial brief p. 68-69
[342] DTE Electric's reply brief p. 108-109

Accordingly, uncollectible O&M expense should be reduced by $234,000 consistent with the Staff's recommendation.

b. Returned Check Charge

DTE Electric proposed to increase its returned check charge from $15.00 to the statutory maximum of $28.66. Ms. Johnson testified that DTE Electric is proposing to use third-party vendors to recover insufficient fund payments by re-presenting non-sufficient funds (NSF) payments to the bank for seven days after the NSF check is presented and remit the payment to the company if funds become available.[343] Ms. Johnson explained that the third-party vendor has an algorithm, which the company does not have, to determine the optimal time to resubmit the check when funds are available. Ms. Johnson testified that the third-party vendor has a 70-85% success rate, which could save the company $350,000 per year in uncollectible expense.[344]

Ms. Johnson explained that by increasing the returned check charge from $15.00 to $28.66, the company expects to deter customers from repeatedly making NSF check payments.[345]

Mr. Pung disagreed with the company's proposal to increase the returned check charge, observing, "Customers who get assessed this charge are often people who do not have a lot of resources and cannot easily absorb such an increase. Staff believes that the current charge of $15 is enough to deter customers from making payments that are returned for insufficient funds so long as it is enforced."[346]

In its initial and reply briefs, Soulardarity supports the Staff's position, that nearly

[343] 7 Tr 3126-3127.
[344] Id. at 3128.
[345] Id. at 3129.
[346] 8 Tr 4287-4288.

doubling the current NSF charge is unreasonable and that “it is objectionable for burdening those with less financial means.”[347]

This PFD agrees with the Staff and Soulardarity, that DTE Electric’s proposal simply increases the financial burden for those who can least afford to pay. DTE Electric’s proposal should therefore be rejected.

9. Corporate Staff Group Expense

In its initial brief, DTE Electric reduced its injuries and damages expense by $0.9 million,[348] recognizing that inflation should not be included as part of this O&M expense, as the Commission has consistently determined, and as recommended by the Staff.[349]

In projecting injuries and damages expense for the test year, DTE used a five-year average to smooth out any year over year variance.[350] Ms. Uzenski testified that the five-year average is consistent with past practice approved by the Commission.

Mr. Coppola testified that the injuries and damages expense should be reduced by $1.9 million, based on his use of a three-year, rather than five-year, average. Mr. Coppola recommended the three-year average in this case because the 2013 injuries and damages amount was significantly higher than the remaining years used in calculating the average. He explained that in 2013, DTE Electric incurred $18 million of actual injuries and damages costs, an amount that is more than $5.0 million higher than more recent expenses. Mr. Coppola testified that the injuries and damages costs ranged from $8 million to $13.2 million during the other four years, thus, the $18 million amount in 2013

[347] Soulardarity’s reply brief, p. 2.
[348] DTE Electric’s initial brief, pp. 1, 65.
[349] 5 Tr 4028.
[350] 7 Tr 3311.

was a significant anomaly. Mr. Coppola acknowledged that the Commission has accepted the use of a five-year average for calculating injuries and damages expense, but he contended that the practice should not preclude a change to the methodology when there are significant events in one year that are not likely to reoccur. Mr. Coppola testified that the three-year average he proposes normalized the cost forecast by removing the unusual amount from 2013.[351] Based on Mr. Coppola's testimony, the Attorney General argues that a three-year average should be utilized in this matter reducing the injuries and damages cost by $1.9 million.[352]

DTE Electric argues that it used a five-year average to normalize fluctuations in annual expense and that this method has been used in prior rate cases. The company argues that the calculation method should be consistently applied across rate cases in accordance with the Commission's past practice. The company asserts that it is not appropriate to change methodologies to derive a more desirable result.[353]

This PFD recommends that the Commission again approve the use of a five-year average, without inflation, in calculating injuries and damages expense. The purpose of using a longer time period in calculating the average is to normalize annual expense fluctuations and address, to a great extent, any atypical years. In addition, this method is consistent with prior Commission orders.

10. Pension and Other Post-Employment Benefits Expense

Mr. Cooper testified regarding DTE Electric's historical and projected pension and other post-employment benefits (OPEB) expense. Mr. Cooper explained that pension

[351] 8 Tr 1612-1613
[352] Attorney General's initial brief pp. 35-36
[353] DTE Electric's reply brief pp. 111-112

costs are comprised of service costs, interest cost, expected return on assets, and amortization.[354] Mr. Cooper testified that pension costs are expected to decrease from $127 in the 2017 historical year to $68.1 million in the projected test year primarily due to an expected increase in the expected return on assets.[355]

Mr. Cooper explained that OPEB costs are comprised of retiree medical, dental, prescription drug, and life insurance benefits. Mr. Cooper testified that these costs, like pension costs, include service costs, interest cost, expected return on assets, and amortization.[356] Mr. Cooper testified that OPEB costs are projected to decrease from a negative $16.3 million in 2017 to a negative $21.3 million during the projected test year resulting in a decrease in OPEB costs of $5.0 million.[357] As is the case for the reduction in pension costs, this change is also largely due to an increase in the expected return on assets.

No party objected to DTE Electric's projected pension and OPEB costs, therefore these costs should be approved.

11. Employee Compensation Expense

Mr. Cooper testified in support of DTE Electric's request to include $46.4 million in projected expenses for its employee incentive compensation programs. The three programs at issue are the Long-term Incentive Plan (LTIP), the Annual Incentive Plan (AIP), and the Rewarding Employees Plan (REP). Mr. Cooper testified that these programs are an integral part of the company's compensation package, and are

[354] 6 Tr 1812-1814.
[355] 6 Tr 1814; Exhibit A-13, Schedule C5.11.1.
[356] 6 Tr 1816-1817.
[357] 6 Tr 1817; Exhibit A-13, Schedule C5.11.2.

necessary to make the company's overall compensation match peer companies and to retain employees. Mr. Cooper also testified that this projected expense excludes incentive compensation for its top five executives.

As he explained the programs, the LTIP is "a multiple year incentive plan, which is available to all managers and above and up to 10% of other non-represented employees."[358] Payouts to eligible employees are in the form of Performance Shares and Restricted Stock, and only the Performance Shares are awarded based on performance objectives. The performance objectives consist of three financial measures evaluated over a three-year period: total DTE Energy shareholder return relative to a peer group; DTE Electric average return on equity; and the ratio of Funds from Operations (FFO) to debt. The relative weightings for each are shown in Exhibit A-21, Schedule K4, separately for DTE Electric employees and DTE Energy corporate services employees.

The AIP is "a short-term variable pay program available to senior management level employees to motivate performance."[359] Senior management includes Vice Presidents and above, and directors. The REP is the version available to all other non-represented employees.[360] Both of these programs contain financial measures including DTE Electric operating earnings, adjusted cash flow, and DTE Energy operating earnings per share. The weightings between financial and operating measures vary depending on the group of employees, so for employees in the nuclear area, the financial measures are weighted less heavily, and for employees in the corporate services area, the financial measures are weighted more heavily. DTE Electric divides the remaining measures used

[358] 6 Tr 1843.
[359] Id.
[360] Id. at 1844.

in the AIP and REP, referred to as the operating metric, into three categories: "customer satisfaction," "employee engagement," and "operating excellence." The metrics in use for 2018, with the weightings, are shown in Exhibit A-21 separately for three groups of employees, DTE Electric, Nuclear Generation, and Corporate Services.[361] For each of the measures, "target level" performance equates to 100% payout, while payout percentages will be lower for performance below target level but above a threshold, and higher for performance above the target level.

Mr. Cooper contended that each plan provides benefits to ratepayers that outweigh the cost, presenting a benefit-cost analysis by performance measure in Schedule K5 of Exhibit A-21.

Ms. McMillan-Sepkoski presented Staff's recommendation that the Commission exclude the projected incentive compensation costs attributable to the financial performance measures. Staff's proposed $27.1 million reduction includes the cost of LTIP program in its entirety and a portion of the costs of the AIP and REP. Ms. McMillan-Sepkoski identified a series of prior Commission orders rejecting funding for the financial performance measures, based on its findings that the financial performance measures primarily benefit shareholders rather than ratepayers. She explained that Staff included projected costs of $19.3 million related to the non-financial performance metrics, also consistent with the Commission's recent orders.[362]

Mr. Coppola recommended that the Commission exclude the projected costs associated with the financial measures and also exclude 50% of the projected costs

[361] Exhibit A-21, Schedules K1 through K3.
[362] 8 Tr 4048-4050.

associated with the non-financial measures. He characterized the plans as "too heavily skewed toward measures that benefit shareholders not customers," and characterized the benefits identified by DTE Electric as "based on a faulty premise of historical cost savings and an expectation that future targets of performance will be achieved."[363] Addressing the financial measures, Mr. Coppola testified that the DTE Electric earnings and cash flow goals provide no direct benefit to customers, and he finds it "even more inappropriate" to charge customers for incentives related to achieving DTE Energy earnings per share "since these earnings include earnings from the gas and non-utility business of DTE Energy."[364]

Mr. Coppola also addressed the non-financial measures. Regarding the measures grouped under the "customer satisfaction" heading, he noted that the benefits identified in Schedule K5 of Exhibit A-21 are less than the projected costs. Regarding the measures included in the "employee engagement" category, Mr. Coppola characterized them as worthy goals, but opined they "do not rise to the level of being measures that are visible to customers nor do they create direct customer benefits."[365] Mr. Coppola also characterized the measures in the "operating excellence" category as worthy goals, but asserted that the electric distribution response time metrics are the only goals with a direct link to customers, and noted that these goals represent only a small share of the projected cost.

Further reviewing the benefit-cost analysis in Schedule K5, Mr. Coppola testified that the company's cost projections are based on the assumption that DTE Electric will

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[363] 5 Tr 1614.
[364] Id. at 1615.
[365] Id.

achieve 100% of the target performance in all measures. Using the information in Exhibit AG-10, Mr. Coppola testified that his analysis of the company's performance under the 2015 and 2016 plans shows target levels were achieved for less than half of the measures.[366] On this basis, and in recognition of the Commission's prior orders addressing incentive plans, Mr. Coppola recommended that the Commission limit funding for the program costs associated with the non-financial measures to 50%, and exclude funding for all financial measures, resulting in a $36.7 million reduction to the company's expense projection.[367]

Mr. Jester also testified on this topic. His analysis was related to his recommendations regarding the company's authorized return on equity, discussed above. He recommended that the Commission exclude recovery of projected incentives for the financial performance measures. He further recommended that the Commission require DTE Electric to propose performance measures in its next rate case that Mr. Jester considers more directly related to customer benefits, based on existing service quality rules and broad criteria such as affordability, pollutant control, and reliability.[368] He explained his selection of these criteria in part by reference to a March 13, 2015 Governor's special message addressing energy issues, and data collected by the federal Energy Information Administration.[369] As with his recommendations regarding performance-based considerations in the context of setting an authorized return on equity, Mr. Jester recommended a stakeholder process to consider acceptable criteria and lead to the development of alternative proposals in the company's next rate case:

[366] 5 Tr 1617-1618.
[367] 5 Tr 1619-1620.
[368] 6 Tr 2158-2159.
[369] 6 Tr 2165-2166.

> I also recommend that the Commission order in the present case that the Company make different proposals regarding incentive compensation in its next rate case. In that next rate case, the Commission should direct that the Company follow a simple "bright line" standard that rate recovery will be allowed for incentives tied to affordability, reliability, pollutant emissions, and other criteria directly measuring the Company's performance for its customers and society and that incentives tied to Company financial performance must be included in return on equity and effectively borne by holders of common stock. Generally, affordability, reliability, pollutant emissions, and any other performance criteria used in incentive compensation programs should be evaluated based on the Company's comparative performance to other electric utilities both nationally and within the State of Michigan. The Commission may want to establish a stakeholder process following on from its preparation of the PBR Report to facilitate its acceptance of such criteria in the Company's next general rate case.[370]

In his rebuttal testimony, Mr. Cooper objected that Staff considered prior Commission decisions, contending that Staff ignored the $10.3 million quantified savings for financial measures shown in his Exhibit A-21, Schedule K5.[371] He also objected that Staff did not evaluate the overall level of compensation, reiterating his earlier testimony that the company's overall level of compensation is reasonable, and presenting Exhibit A-32, Schedule V1, to show the results of the company's most recent (2017) study.

In response to Mr. Coppola's testimony that the financial measures do not provide direct benefits to customers, Mr. Cooper reiterated his direct testimony that maintaining the company's credit rating and achieving operating efficiencies are benefits attributable to the financial measures.[372] Addressing Mr. Coppola's conclusion that many of the operating measures also do not provide customer benefits, Mr. Cooper identified the benefit values he attributes to distribution system reliability and generating plant performance levels.[373] Mr. Cooper also objected to Mr. Coppola's recommendation to

[370] 6 Tr 2163-2164.
[371] 6 Tr 1866-1867.
[372] 6 Tr 1869-1871.
[373] 6 Tr 1871.

exclude 50% of the projected cost of the operational performance measures for the AIP and REP programs because 2015 and 2016 program results show that the company achieved only approximately 50% of the target performance levels. He testified that a two-year period is insufficient to evaluate the program. He also presented 2013-2017 program results, not in the same format as Mr. Coppola's exhibits, in Schedule V2 of Exhibit A-32. He explained that he had not presented this information as part of the company's direct case because "it is more typical for the Company to provide the historical incentive plan performance results in response to discovery requests."[374] He further explained that DTE Electric had provided the 2016 results in Case No. U-18255 because "the Commission had required the Company to submit this information in its order in case No. U-18014."[375] Mr. Cooper's Schedule V2 also presented a measure of the "average" performance payout for the operating measures under each plan (AIP and REP) for each group of employees (DTE Electric, nuclear generation, and corporate services) for each year and overall. He explained his analysis:

> The average annual performance method reflected on Exhibit A-32, Schedule V2 is a more accurate method of measuring historic performance than the approach used by Witness Coppola. Under the AIP, payouts range from 25% for Threshold performance to 175% for Maximum performance with 100% payouts for Target performance. Payouts under the REP range from 50% for Threshold performance to 150% for Maximum performance with 100% payouts for Target performance. Thus, if the actual performance is less than Target but higher than Threshold, payouts under the AIP would range between 25% to 100% and the REP payouts would range between 50% and 100%. For example, if the actual number of MPSC Complaints in 2018 is 1,682, or only one higher than the 1,681 Target, the payouts under the AIP and REP would be 99.3% and 99.5%, respectively. In contrast, Witness Coppola's approach would deem the same actual performance for MPSC Complaints to be less than Target and therefore would presume a zero payout. Similarly, Witness Coppola's method ignores the impact of

[374] Id. at 1873.
[375] Id.

> performance above Target, which could result in payouts of 150% for the REP and 175% for the AIP when Maximum performance levels are achieved.[376]

He also testified that some of the targets reflect ambitious goals, such that "if Targets are not met in one year, customers still benefit from improved performance levels."[377] Mr. Cooper disputed that it would be reasonable to assume the company would only achieve target-level performance in 50% of the measures in the test year.[378]

Addressing Mr. Jester's recommendations, Mr. Cooper disputed that alternate performance measures should be considered, characterizing the company's program as "carefully balanced," and emphasizing it has been developed over 20 years. [379]

In its brief, the Staff urges the Commission to provide funding only for the projected costs associated with target performance for the non-financial measures in the AIP and REP programs, and to provide no funding for the LTIP program because it is based entirely on financial performance measures.[380] The Staff comprehensively cites prior Commission orders finding that financial performance measures primarily benefit shareholders.

The Attorney General urges the Commission to adopt Mr. Coppola's $36.7 million adjustment, arguing that the incentive compensation plans are too heavily skewed to measures that benefit shareholders not ratepayers, and that DTE Electric's presentation of customer benefits are based on a faulty premise of historical savings and faulty believe that future targets will be maintained.[381] Addressing Mr. Cooper's rebuttal testimony, the

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[376] 6 Tr 1875.
[377] Id.
[378] Id. at 1876.
[379] 6 Tr 1786-1787.
[380] Staff's initial brief, pp. 66-68.
[381] Attorney General's initial brief pp 36-43; reply brief, p. 21.

Attorney General responds to Mr. Cooper's claim that an improvement in all-weather SAIDI provides quantifiable benefits to customers by noting the significant increase in all-weather SAIDI in 2017 due to severe storms, as shown by Mr. Bruzzano's testimony at 4 Tr 703. The Attorney General argues that SAIDI statistics, both all-weather and without major event days, have been up and down since 2012. The Attorney General also argues that the company's track record regarding the operating measures shows only about 50% of target performance levels are achieved. Noting that Mr. Cooper presented 2017 levels in his rebuttal testimony, she argues that no analysis of that information was possible, also citing the 2017 information DTE Electric subsequently provided in discovery, included in Exhibit AG-41, which shows the performance achieved by specific measure.

In their brief, MEC/NRDC/SC argue the Commission should reject the company's proposed incentive compensation costs because the program incentives are tied too closely to financial performance measures, and fail to create appropriate incentives. Instead, MEC/NRDC/SC contend, the Commission should only approve an incentive compensation structure that encourages employees to improve DTE Electric's performance on the types of metrics that would be included in performance-based ratemaking, including affordability, reliability, pollutant control, and low-income program efficacy. They cite Mr. Jester's testimony. They also contend Mr. Cooper failed to recognize that the company's financial performance measures provide incentives to overstate expected costs to the Commission in rate cases, or to underspend what is needed to deliver results to customers. Recognizing that the Commission may be reluctant to "rapidly disrupt DTE's terms of employment," MEC/NRDC/SC recommend that the Commission commence a stakeholder process like the one they seek for performance-based measures to be used in ROE determinations.[382]

In its reply brief, the RCG concurs with Staff's recommendations, noting that the Commission has repeated rejecting including costs associated with incentive compensation based on financial performance metrics. It also cites what is characterizes as the "dysfunctionality" of DTE Electric's IT and billing systems, arguing that customers have not benefitted from the program incentives.[383]

Kroger does not address the incentive compensation program or expense projections in its brief, but does ask the Commission to take remedial action to address service quality problems.[384]

In support of its requested recovery of the projected $46.4 million cost associated with target level performance in each of its programs, DTE Electric relies on Mr. Cooper's testimony and exhibits. In its brief and reply brief, DTE Electric argues that it has established that its overall compensation levels are reasonable, and that its incentive compensation program, including both financial and non-financial measures, provides benefits to customers in excess of cost.[385] DTE Electric argues that Staff did not introduce evidence that its overall compensation levels are unreasonable, and further objects to Staff's reliance on prior Commission orders addressing its incentive compensation plans to support rejection of the costs associated with the financial measures. It argues that the Commission's decision in each rate case must be based on the record in that case and that the Commission may not "categorically" disallow funding for the program costs

382 MEC/NRDC/SC's initial brief, pp. 104-106.
383 RCG's reply brief, p. 6.
384 Kroger's initial brief, pp. 17-18.
385 DTE Electric's initial brief, pp. 86-91; reply brief, pp. 119-128.

associated with financial measures. It argues the Attorney General's and MEC-NRDC-SC's recommendations to exclude the program cost of financial measures should be rejected on the same basis. DTE Electric asserts that it has demonstrated "substantial benefits" related to the financial measures, citing Schedule K5 in Exhibit A-21 as explained by Mr. Cooper.

DTE Electric argues that Exhibit A-21 fully supports a net customer benefit of $77.3 million for the three programs, highlighting is use of distribution system reliability and generating plant performance metrics. It further argues that certain metrics can provide benefits to customers while evading specific quantification. Citing Mr. Cooper's testimony at 6 Tr 1871, DTE Electric argues:

> 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.[386]

Addressing Mr. Coppola's recommendation to reduce funding for the non-financial measures, DTE Electric disputes that Mr. Coppola's analysis of the 2015 and 2016 plans is persuasive, contending that Mr. Cooper's rebuttal analysis as reflected in Exhibit A-32, Schedule V2 is a more accurate analysis of the company's performance under the plan:

> 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 (6T 1875). 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

[386] DTE Electric's initial brief, p. 89; reply brief, p. 123.

> assume that the Company will, on an overall basis, achieve target performance levels.[387]

DTE Electric argues that in Case No. U-18255, the Commission "relied on similar evidence to reject essentially the same argument that the AG repeated in this case."[388] DTE Electric similarly cites the Commission's decision in Case No. U-17999, the most recent rate case for DTE Gas. Addressing MEC-NRDC-SC's recommendation that the Commission require consideration of alternate performance measures, DTE Electric relies on Mr. Cooper's rebuttal testimony to support its contention that the company's incentive compensation plans are carefully balanced and have evolved over 20 years, while disputing Mr. Jester's expertise.[389]

The ALJ finds that the Staff's recommendation to exclude the projected $21.7 million cost of the financial measures associated with the incentive compensation programs should be adopted. The Commission addressed DTE Electric's incentive compensation plan less than a year ago in its April 18, 2018 order in Case No. U-18255 and concluded that the financial measures in the LTIP, AIP and REP did not provide sufficient ratepayer benefits to justify including the cost in rates. As DTE Electric argues, the Commission also included the projected costs associated with the non-financial measures of the AIP and REP in the test year revenue requirement in that case. The Commission explained:

> The Commission adopts the recommendation of the ALJ with regard to the disallowance of incentive compensation tied to achieving financial measures. This is consistent with prior Commission decisions and is reasonable and prudent given that these measures do not benefit

[387] DTE Electric's reply brief, p. 124, citing 6 Tr 1876.
[388] DTE Electric's reply brief, p. 125, citing the Commission's April 18, 2018 order in Case No. U18255, p.49.
[389] DTE Electric's reply brief, p. 122. DTE Electric also cites its discussion of MEC/NRDC/SC's recommendations in the context of the authorized return on equity.

> ratepayers. As noted in the last rate case, "[t]he Commission agrees that the company failed to support its request for incentive compensation related to financial metrics, specifically noting that the purported benefits to ratepayers that DTE Electric cites are attenuated at best, and in some cases, specious." The 2017 order, p. 85. However, regarding the additional 50% disallowance proposed by the Attorney General, the Commission declines to adopt the ALJ's recommendation. 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 through 2016. 7 Tr 837. When looking at historical performance over a longer period, the Attorney General's recommendation that 50% should be disallowed is simply not supported. Therefore, the Commission adopts the Staff's proposal to disallow $26,574,000 related to financial metrics.

While DTE Electric objects to reliance on the Commission's decision in that case to exclude the cost of its financial performance measures, a review of DTE Electric's February 14, 2018 Exceptions to the PFD in Case No. U-18255 shows that DTE Electric presented the same arguments in support of its position in that case that it presents in this case. The Commission's April 18, 2018 order as well as DTE Electric's exceptions show that the company based its analysis of these programs on data available through 2016, just as the company did in its initial filing in this case. The only notable differences between DTE Electric's arguments in this case and in its last rate case are that in Case No. U-18255, DTE Electric asserted that its projected O&M expenses were $411 million less than they would have had they increased at the rate of inflation from 2007, while in this case, DTE Electric asserts that its O&M expense projections are $226.2 million less than they would have been had they increased at the rate of inflation from 2009; and in Case No. U-18255, DTE electric asserted that the benefit-cost analysis demonstrated net benefits of $155.3 million, while in this case, it asserts that its benefit-cost analysis demonstrates net benefits of $77.3 million. The ALJ notes that although DTE Electric argues that its request should be judged on the basis of the record created in this case, it has failed to claim that it has presented new information or a new analysis that would justify a different result than reached in Case No. U-18255.

Considering the company's claims without regard to the Commission's prior determinations, however, the ALJ finds that in the present case the company has not supported its claim that customers benefit from the financial measures. Indeed, borrowing the words the Commission used in Case No. U-18255, the company's claimed customer benefits from the financial measures are "attenuated at best, and in some cases, specious." As shown in Exhibit A-21, line 14, the company's analysis purports to show net benefits from the financial measures across all of its programs totaling only $10.4 million.[390] The LTIP is shown as having a net cost to customers of $2,569,000. The AIP is shown with a net benefit of $855,000, and the REP is shown with a net benefit of $12,094,000. A primary benefit the company assigns to the financial measures is based on an estimate of O&M cost savings relative to the rate of inflation. Mr. Cooper testified that the annual benefit of $21.9 million was calculated by dividing the O&M savings estimate of $226.2 million by 10.33 years, the time period from 2009 to the test year over which the savings were measured. The $21.9 million annual savings was then allocated to each of the three incentive programs in proportion to the related expenses.[391] Not only does the company have an incentive to reduce costs between rate cases, but the company would be expected to have productivity gains over the same period of time. Note that recent rate orders have provided for substantial capital expenditures. And, in addition, as Mr. Jester persuasively testified: "[I]ncentives based on financial

[390] Exhibit A-21, Schedule K5, line 14.
[391] 6 Tr 1855-1856.

performance are as much an incentive to overstate expected costs to the Commission or to underspend what is needed to deliver results for customers (e.g., reducing tree trimming below needed levels to improve financial performance) as it is to pursue cost-effectiveness as outlined by Mr. Cooper."[392] At heart, DTE Electric is asking the ratepayers to fund the cost of the financial measures in part to motivate the company to spend an average of $21.9 million less than included in the revenue requirement calculated in this case.

The other benefit assigned to the company's financial measures is the potential cost to ratepayers of a reduction in the company's credit rating. Mr. Cooper testified that the annual benefit of $15.6 million was calculated by applying the 2018 yield spread between A-rated and BBB-rated bonds to the long-term debt balances in the company's capital structure.[393] Ascribing this benefit to the financial component of the incentive programs ignores the significant amounts charged to ratepayers to maintain the company's credit rating. In its most recent rate case, Case No. U-18255, the Commission's revenue requirement included income of $815 million before the application of the tax multiplier.[394]

MEC/NRDC/SC's recommendation for a review of performance measures is addressed above in the discussion of the cost of equity.

[392] See 6 Tr 2163.
[393] See 6 Tr 1856, also citing Exhibit A-14, Schedule D1.
[394] See April 18, 2018 order, page 59.

12. Other Operations and Maintenance Expense Adjustments

a. Weekend Flex/Fixed Bill Pilot Program Expense

DTE Electric is proposing to include $0.4 million and $1.0 million in O&M expense for the Weekend Flex and Fixed Bill pilot programs respectively. As discussed in more detail below, the ALJ finds these pilot programs should not be approved. Therefore, associated O&M costs should be disallowed.

b. Edison Electric Institute Dues

Mr. Rábago recommended that $1,269,000 in dues that DTE Electric pays to the Edison Electric Institute (EEI), and charges to ratepayers, be disallowed.[395] According to Mr. Rábago, DTE Electric belongs to many trade associations, including EEI, however, "[u]nbeknownst to most customers, these payments may be used to fund advocacy with which customers may disagree and that is contrary to their interests."[396] Mr. Rábago explained that some portion of EEI dues, the part associated with the organization's lobbying efforts, is excluded from O&M expense, but that amount is determined by EEI and reported to DTE Electric on EEI's invoice.[397]

Mr. Rábago concluded that, "[t]he Company has failed to demonstrate that the costs associated with EEI membership dues are limited to activities that benefit ratepayers and therefore are just and reasonable. The Company has failed to demonstrate that it has removed all payments for lobbying and other inappropriate activities from the costs it seeks to recover from customers. The Company produced no

[395] 6 Tr 2520; Exhibit A-3; Schedule C14, line 4.
[396] 6 Tr 2520.
[397] 6 Tr 2521; Exhibit MEC-31.

evidence that it verified the assertions from EEI."[398] Consistent with his testimony, Mr. Rábago recommended a disallowance of $1.27 million for EEI dues.

DTE Electric did not respond in testimony or briefs to this proposed disallowance.

Although Mr. Rábago discussed several efforts that EEI undertakes that clearly provide ratepayer benefits, including workforce education and training, public safety campaigns, and EEI's mutual assistance program, he also pointed out that it is unknown what portion of EEI's total operating budget ($96.5 million) is dedicated to lobbying efforts that may not be in ratepayers' interests. Mr. Rábago also pointed out that there are no recent audits of EEI's spending and that some other state utility commissions are beginning to address the concerns about lack of transparency in EEI expenditures.[399] This PFD finds that absent any evidence from DTE Electric rebutting Mr. Rábago's testimony, MEC/NRDC/SC's proposed disallowance of EEI dues in the amount of $1,269,000 should be adopted. In future rate cases, DTE Electric may provide stronger evidence that the portion of EEI dues assigned to ratepayers actually accrues to their benefit.

13. Depreciation and Amortization Expense

Based on the decisions made in this PFD, DTE Electric's requested recovery of $883.6 million for Depreciation and Amortization expense, after adjustment for Case No. U-18150, and including other adjustments made by the company in its brief and reply brief, is calculated as $875,900,000, as shown in Appendix A, page 3.

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[398] 5 Tr 2521.
[399] 6 Tr 2523-2524.

14. Tax Expense

a. Property and Other Tax Expense

As DTE Electric stated in its initial and reply briefs, there appears to be no dispute over the company's calculation of property tax expense of $275.5 million and other tax expense of $52.2 million for the test period. These amounts should therefore be approved.

b. Federal Income Tax Expense

The differences in federal income tax (FIT) expense between DTE Electric and the Staff are related to the adjustments the Staff made to the company's case. DTE Electric points out in its reply brief that the Staff and company appear to be in agreement on the effects of the TCJA on federal tax. ABATE's regulatory plan is discussed above.

VII.

OTHER REVENUE-RELATED ISSUES

A. Electric Vehicle Pilot (Charging Forward)

In its direct and rebuttal cases, DTE Electric presented evidence to explain its proposed "Charging Forward" program; a three-year coordinated set of pilot projects that focus on the "advancement of on-road transportation electrification."[400] DTE Electric

[400] 8 Tr 3543, 3564. For additional background information regarding electric vehicles and related infrastructure, see 8 Tr 3544-53. For evidence regarding the economic benefits of vehicle electrification in

developed Charging Forward after numerous meetings with stakeholders and after participation in the Commission's electric vehicle (EV) technical conferences.[401] DTE Electric believes it has three key roles to play in the expansion of the electric vehicle sector: grid integration and interaction; education; and the construction and support of the necessary charging infrastructure.[402]

To date, DTE Electric's EV experience has been limited to a few pilot programs, such as: analyzing residential charging behavior by providing a flat fee charging tariff and an EV TOU tariff, providing incentive programs for Level 2 residential charging stations, supporting non-residential EV charging infrastructure, and developing plans for three direct current fast charging (DCFC) stations in southeast Michigan.[403] Mr. Serna testified that DTE Electric believes that the "combination of the pilots and [Charging Forward] will provide DTE a series of additional technical learnings that will inform future activities."[404]

In addition, in coordination with its Charging Forward program, DTE Electric plans to: support Delta Electronics' development of extreme fast charging up to 400 kW; work on possible DR pilot options with Ford Motor Company to gain understanding of the value of delayed and interrupted charging; and install a corridor fast charging station powered by battery storage.

To advance transportation electrification, Mr. Serna testified that Charging Forward needs to address a lack of EV awareness and the currently ad-hoc and deficient

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Michigan, see 8 Tr 3582-84. Neither of these topics will be extensively reviewed as it is agreed by all that the near-term electrification of the auto sector is a near certainty with enormous benefits.

[401] 8 Tr 3564.

[402] 8 Tr 3555.

[403] 8 Tr 3557.

[404] Id. at 3558.

EV infrastructure.[405] DTE Electric developed Charging Forward following four guiding principles: (1) helping customers realize the benefits of EVs; (2) efficiently integrating EV load with its distribution system; (3) reducing barriers to adoption; and (4) participation in infrastructure deployment through partnerships.[406] Mr. Serna added:

> The Charging Forward program will help DTE understand the market and its customers, learn about EV load and its relationship to overall system load, and understand EV impact on the distribution system. Several metrics will be tracked to gauge impact of the Charging Forward program and improve the Company's understanding of the EV market, including:
>
> - EV volume in Michigan and DTE's electric service territory;
> - Charging behavior (percent off-peak vs. on-peak);
> - Customer awareness of EVs;
> - Site host interest and participation in the program;
> - Customer participation in TOU rates;
> - Average make-ready cost per port and site; and
> - Station utilization.[407]

As proposed, DTE Electric projected that implementation of Charging Forward will cost approximately $13 million, with $2,790,000 expended in 2019, $5,123,000 expended in 2020 and $5,203,000 expended in 2021.[408] DTE Electric's plans call for management of the Charging Forward program by two full-time employees at an estimated total cost of $933,000 over the three-year span of the program.[409] Capital expenditures, which consists of the cost of service buildouts up to the service meter, are projected to cost $1,066,000 in 2019, $2,033,000 in 2020, and $2,093,000 in 2021.[410] DTE Electric seeks approval to recover these capital costs as normal assets included in rate base.[411]

[405] 8 Tr 3562.
[406] Id.
[407] 8 Tr 3585.
[408] 8 Tr 3579-82; Exhibit A-12, Schedule B5.9.
[409] 6 Tr 2084.
[410] Exhibit A-12, Schedule B5.9.
[411] 8 Tr 3580-3581.

Regulatory asset costs, which consists of program rebates, are projected at $1,090,000 in 2019, $2,140,000 in 2020, and $2,160,000 in 2021.[412] DTE Electric also seeks authority to defer and amortize these rebates as a regulatory asset over five years.[413] After a review, the deferred rebate costs are to be included in rate base.[414]

O&M expenses, consisting primarily of consumer education/outreach and program management, are projected to cost $633,000 in 2019 and $950,000 in both 2020 and 2021.[415] DTE Electric proposes to recover O&M expenses as base O&M.[416]

As proposed, Charging Forward will include education and outreach to residential and commercial customers via, among other things, social media, newsletters, email, and direct mail. DTE Electric's education and outreach endeavor has two primary objectives: to increase EV adoption and to promote the EV charger and infrastructure components of the program. DTE Electric projects total education and outreach costs of approximately $1,600,000 over the three-year life of the program.[417]

To support residential charging, DTE Electric will offer rebates[418] to approximately 2,800 EV owning residential customers who: (1) install a qualified "smart"[419] Level 2 charger; (2) enroll in year-round TOU rates, and; (3) agree to enroll in future, currently undeveloped, DR programs.[420] On a related matter, during the course of this hearing,

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412 Exhibit A-12, Schedule B5.9.
413 8 Tr 3581.
414 7 Tr 3048.
415 Exhibit A-12, Schedule B5.9.
416 8 Tr 3614.
417 6 Tr 2080-2085.
418 DTE Electric originally proposed a rebate cap of $500. As explained below, the parties have since agreed to remove all rebate caps from consideration.
419 For an explanation of "smart" charger attributes, see 7 Tr 3047. Of note, is their ability to separately measure electricity usage. 7 Tr 3047.
420 8 Tr 3565-66.

Staff called for elimination of DTE Electric's EV flat monthly rate.[421] DTE Electric agreed and has proposed to stop offering the EV flat monthly rate and to work toward the transition of all current EV flat monthly rate customers to a new rate by December 31, 2019.[422]

To enhance infrastructure, DTE Electric intends to focus on three categories of charging; DCFC stations, Level 2 stations, and Fleet charging stations.[423] DTE Electric plans to invest in EV charging infrastructure using a "make-ready" model, under which, DTE Electric will contribute EV service connection costs, up to the meter, in the form of capital and will waive contribution in aid of construction tariff provisions.[424] For EV supply infrastructure, i.e. after the meter costs, including panel, conduit, and wiring, DTE Electric originally proposed rebates of up to $20,000 to site hosts.[425] Charger site hosts will be responsible for the charger costs.

DTE Electric plans to ensure all DCFC infrastructure is publicly accessible and concentrated on sites along highway corridors with consideration given to "showcases" in downtown areas.[426] DTE Electric estimates deployment of approximately 32 DCFC chargers over the 3-year program.[427] Public Level 2 charger infrastructure development

[421] 8 Tr 3417.
[422] 8 Tr 3618.
[423] 8 Tr 3567-68.
[424] 8 Tr 3568. As more of a housekeeping measure, many parties proposed waiving of the contribution in aid of construction tariff provisions. DTE Electric agreed and, at 8 Tr 3621-22, DTE Electric recommended the following tariff language be included in Section C6.1 (16):

> Beginning in May 2019, the Company will waive the contribution in aid of construction calculated pursuant to Section C6 for the term of the Company's Charging Forward program, in order to construct and extend its facilities to serve new loads associated with three categories of electric vehicle charging stations. These categories include: (1) DC Fast Charging stations, (2) Level 2 Charging stations, and (3) Fleet Charging stations.

[425] 8 Tr 3568-69. As explained below, the parties have since agreed to remove all rebate caps from consideration.
[426] 8 Tr 3569-70.
[427] Id. at 3575.

will focus on workplaces, multi-unit dwellings (MUDs), and other high visibility locations. DTE Electric originally proposed Level 2 charger after-the-meter infrastructure rebates of $2,500 per port. DTE Electric estimates deployment of approximately 1,000 Level 2 chargers over the 3-year program.[428]

DTE Electric plans to provide the make-ready charging infrastructure required for fleet transportation categories, including public transit buses, school buses, delivery vehicles, and shared mobility services.[429] 8 Tr 3573-74. DTE Electric originally proposed to provide "an after-the-meter rebate for fleet infrastructure equivalent in value to the capital costs up to the meter for each station." DTE Electric has no estimate of the number of fleet charging stations it expects will be deployed over the course of the program. [430]

As already noted, DTE Electric has removed rebate caps from the Charging Forward program. This program change resulted after both Staff and MEC recommended that, to enhance program flexibility, the Commission not establish set rebate caps, but to allow DTE Electric the discretion to offer rebates as program demands require.[431] DTE Electric has incorporated this recommendation into Charging Forward and now proposes the same.[432]

As for pricing at public Level 2 and DCFC charging sites, at Mr. Serna explains:

> DTE expects most Level 2 charging will be offered for free to EV drivers based on current market expectations, but that DCFC will likely require a fee for EV driver use. In either case, DTE proposes that site hosts will be able to choose what they "charge for charging". DTE will educate hosts on what pricing structures are currently allowed in Michigan (i.e., on a time

[428] 8 Tr 3571-3575. Mr. Clinton explained DTE's site host acquisition strategy at 6 Tr 2085-88.
[429] For additional details regarding DTE's strategies for each fleet category, see 8 Tr 3574-75.
[430] 8 Tr 3573-3575
[431] 8 Tr 3420. 6 Tr 2214-15.
[432] 8 Tr 3620

> basis vs. a per kW-hour basis), what their expected electricity costs could be, and what the gas price equivalent would be.[433]

At the urging of Mr. Ozar,[434] Mr. Serna testified that DTE Electric will, as part of Charging Forward, update a decade old EV-Grid Impact Study.[435]

The near-term electrification of the North American auto sector appears certain. Unfortunately, Michigan's electric infrastructure is currently unprepared for this transformation and, in fact, stands as a barrier to the practical adoption of this emerging technology. With exception of the Attorney General,[436] no party objects to the core components of DTE Electric's proposed Charging Forward program, as detailed above. The parties do, however, propose several modifications to the program which will be addressed separately, below.

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[433] 8 Tr 3579,

[434] Mr. Ozar testified:

> It has been 10 years since [DTE Electric's PEV pilot/grid study]. This landmark study resulted in a core understanding that utilities must "actively manage" PEV charging in order to preemptively mitigate adverse grid-impacts associated with uncontrolled charging. Because the PEV landscape has changed significantly over this past decade, creating uncertainty in the details needed to accomplish such an overarching goal, a new study to refresh, update, and expand the original work is both prudent and in the public interest. For these reasons, it is recommended that a new DTE study be approved by the Commission. A preliminary study framework, including key partnerships, estimated costs, and study objectives be filed in this docket within 6 months of the date of the Commission's order in this proceeding. It is recommended that such study be completed by DTE within the timeframe of the Charging Forward program.

[435] 8 Tr 3614.

[436] The Attorney General objects to the make-ready aspect of the program, arguing that elimination of contributions in aid of construction results in subsidization of these costs by all other rate payers. Attorney General's initial brief, pp. 72-73. Thus, the Attorney General recommends that the Commission "approve the bulk of the 'Charging Forward' pilot program but reject the Company's 'Make-Ready' proposal and the related capital expenditures of $1,744,000 in the projected test year." Id. at 74. This PFD finds that following the Attorney General's recommendation would result in significantly handicapping the program. Her position is therefore not adopted.

1. <u>School Bus Pilot</u>

Mr. Ozar expressed the Staff's position that the school bus pilot be significantly expanded, stating:

> [Charging Forward should] include a substantial vehicle-to-grid pilot that tests the provision of storage services, demand response services, and other relevant ancillary services. An expanded school-bus pilot will likely require the provision of credits for the value of energy services provided, and in addition, a financial offset to the school system to cover the risk of accelerated battery degradation. The Staff recommends an enhanced school-bus pilot be approved, with the additional costs covered by the recommended increased spending cap for the Charging Forward program as a whole.[437]

Mr. Ellis supported the Staff's proposal noting that:

> ChargePoint is a partner on a recently-filed pilot project in New York with ConEdison that is investigating vehicle-grid integration ("VGI") opportunities with electric school buses, and such opportunities would create significant value for communities throughout the Company's service territory.[438]

Mr. Serna expressed DTE Electric's reluctance to expand the school bus pilot, testifying:

> Overall the Company supports the proposal to incorporate additional pilot elements into the school bus category, but the Company's initial objective will be to find school districts that are willing to add electric buses to their fleets. Once the school district(s) are identified, the Company will work collaboratively to determine potential pilot scope additions and evaluate the related costs and benefits within the available program funding. Therefore, the Company believes it is premature to request additional expenditures and Charging Forward activity related to school bus electrification.[439]

In its initial brief, the Staff recommends that "the school bus pilot be expanded beyond the Company's investment in make-ready infrastructure to include a vehicle-to-grid pilot that tests the provision of storage services, demand response services, and other

[437] 8 Tr 3412-13.
[438] 7 Tr 3063.
[439] 8 Tr 3615.

ancillary services."[440]

ELPC supports the Staff's expansion proposal, arguing that compensation for grid services provided by school buses makes these buses "more affordable for districts that incur significant up-front costs to purchase them."[441]

ChargePoint also supports an expanded school bus pilot to explore vehicle-to-grid opportunities adding that DTE Electric's "service territory could . . . be well-served by exploring the value . . . of adding electric school buses to the grid."[442]

DTE Electric opposes Staff's proposal, arguing that:

> [T]he Company's initial objective will be to find school districts that are willing to add electric buses to their fleets. Once the school district(s) are identified, the Company will work collaboratively to determine potential pilot scope additions and evaluate the related costs and benefits within the available program funding. In addition, the Company will work with the school district to identify sources of funding other than DTE Electric. Therefore, the Company believes it is premature to request additional expenditures and Charging Forward activity related to school bus electrification.[443]

The Staff's recommendation is well taken. Charging Forward is, in large part, a collection of pilot programs designed to inform DTE Electric and the Commission about, among other things, EV consumer behavior, EV technical issues, and the costs and benefits related to the electrification of Michigan's transportation sector. School buses are certainly an important part of that sector and potentially represent a storage resource to be integrated into the grid. Recognizing that significant additional costs are likely associated with Staff's expanded School Bus Pilot program, it is, none-the-less very

[440] Staff's initial brief, p. 107.
[441] ELPC's reply brief, p. 7.
[442] ChargePoint's reply brief, p. 11.
[443] DTE Electric's reply brief, p. 14.

important that this option be explored. In addition, it is equally important that the financial risks associated with piloting the new technologies involved not fall on our schools. Therefore, it is recommended that the Commission adopt Staff's proposal for an expanded School Bus Pilot Program.[444]

2. <u>80 Amp Charging Pilot</u>

Mr. Ozar recommended Commission approval of "an 80A charging pilot within the medium/heavy duty vehicle components of the Charging Forward program, as this is an emerging charging technology that has not been extensively vetted by an electric utility in Michigan."[445]

Mr. Ellis, "appreciate[s]" Staff's recommendation, but adds:

> The EV charging industry is constantly bringing new products and services to market to meet rapidly evolving e-mobility needs. . . . I would encourage the Company and Commission to consider a technology-agnostic pilot to explore innovative charging solutions for medium- and heavy-duty vehicles. This will allow the market to evolve appropriately while also supporting the deployment of infrastructure that will lead to grid benefits, while also providing the Company and the Commission the opportunity to evaluate a broader set of techniques to accelerate the transition of medium- and heavy-duty fleets to electric fuel, which will have outsized benefits to the grid, environment, economy, and ratepayers across Michigan.[446]

In response, Mr. Serna testified that:

> The Company supports 80 Amp charging, but does not believe that an additional piloting element is necessary to properly promote the concept. The Company will educate customers on this available technology as part of its site host acquisition strategy. Any site host that requests this new

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[444] While DTE Electric has great leeway in formulating a School Bus Pilot Program, the Commission envisions DTE Electric providing significant financial and technical support to the participating schools to ensure the schools, who are essentially serving as guinea pigs in a larger EV experiment, are held financially harmless.
[445] 8 Tr 3413.
[446] 7 Tr 3061,

technology will be able to receive it when it meets the connectivity and data sharing requirements of Charging Forward.[447]

Consistent with the testimony of their respective witnesses, initial brief, the Staff proposes that DTE Electric undertake an 80 amp charging pilot for medium/heavy duty vehicles "because it is an emerging charging technology that the Company should explore and as of yet has not been extensively vetted in Michigan."[448] ChargePoint, however, "encourages the Commission to require technology-agnostic pilots to avoid focusing on one technological solution for medium- and heavy-duty vehicles."[449]

DTE Electric states that it "supports 80 Amp charging, but does not believe that an additional piloting element is necessary to properly promote the concept."[450] Rather, DTE Electric "will educate customers on this available technology as part of its site host acquisition strategy. Any site host that requests this new technology will be able to receive it when it meets the connectivity and data sharing requirements of Charging Forward".[451]

The Staff's interest in exploring the potential benefits of 80 amp EV charging is warranted. However, as suggested by ChargePoint, at this early stage, it's best the Commission take a technology neutral position regarding Charging Forward implementation. With the rapidly changing technology of vehicle electrification, it is appropriate to permit the involved parties to determine what arrangements and technologies best meets their needs and the goals of the Charging Forward program. While 80 Amp charging technology is certainly in the mix, it is premature to highlight it as

[447] 8 Tr 3615.
[448] Staff's initial brief, p. 107.
[449] ChargePoint's reply brief, p. 11.
[450] DTE Electric's reply brief, p. 141.
[451] Id. at 141-142.

a Commission preferred technology. For this reason, it is recommended that the Commission take no action regarding Staff's proposal.

3. Future-proofing

Concerned with obsolescence and the "near-certain stranding of program-funded assets" of DTE's planned investments in 50 kW infrastructure, Mr. Ozar posited that it "is eminently prudent that the upstream charging infrastructure . . . be futureproofed" for upgrading to ultra-fast 150 to 350 kW charging rates.[452]

Similarly, citing the current installation of 350 kW chargers by Electrify America, Mr. Jester recommended that DTE Electric "plan infrastructure and adopt standards to support this higher level of charging throughput."[453] Likewise, Mr. Ellis supports future proofing measures, testifying that:

> [C]ommercial EV charging sites [should] be "future proofed" wherever feasible, provided that additional funding is made available to the Program for this purpose. Future proofing addresses the inevitable growth of the EV and EV charging markets, and entails the construction of additional make-ready "stub outs," including the cost of trenching, boring, conduit, wiring, labor, mounting, while the "ground is open." Future proofing helps EV charging sites prepare to scale up over time as EV adoption increases without having to "reopen" the ground when additional charging capacity is needed. Consolidating current and future make-ready site preparation will avoid significant unnecessary retrofit costs in the future, while ensuring flexibility to allow for advances in EV charging technology over time.
> Future-proofing sites should not come at the expense of reductions to the number of ports that would have been deployed through the Program to meet near-term charging needs. I recommend increasing the Program's total budget to allow for future proofing of participating sites.[454]

Mr. Serna testified that "[t]o the extent 'future-proofing' is possible and reasonable, . . . the Company will do so . . . [w]hen the site host expresses interest". Further, Mr.

[452] 8 Tr 3414.
[453] 6 Tr 2212-2213.
[454] 7 Tr 3055-3056,

Serna testified, DTE Electric "will not require that all sites be 'future-proofed' for a few reasons", including: "losses on the electrical system" caused by oversized transformers, the Company's belief that there will be an ongoing "need for the existing Level 2 and DCFC 50 kW infrastructure", and the Company's desire to not "unnecessarily burden utility customers with cost intensive 'future-proofing' that is not yet market ready."[455]

In its initial brief, the Staff argues:

> DCFC chargers should occupy prime locations within the Company's service territory. However, if the Company is to invest in DCFC charging in these prime locations, it must do so with an eye towards potential future upgrade to its proposed 50 kW make-ready infrastructure to accommodate ultra-fast 150-350 kW charging rates. The essential point is that if stranded investment is to be avoided, the Company should take proactive measures to future-proof the make-ready infrastructure associated with those DCFC sites that are most likely to be upgraded in response to DCFC infrastructure technology moving beyond the 50kW charging paradigm currently contemplated in the Charging Forward Program. Staff believes that if ratepayers' investment is to be protected, then the mitigation of near-certain stranding of program-funded assets should take precedence over any interim loss in interconnection efficiency caused by temporarily oversized interconnections. Therefore, Staff urges the Company to invest in DCFC ultra-fast 150-350 kW infrastructure in these prime locations.[456]

ChargePoint also supports future-proofing, arguing that:

> [A]dditional make ready "stub outs" (beyond the number of initially deployed ports) should be constructed, streamlining future installation of additional EVSE and avoiding significant—and unnecessary—retrofit costs in the future . . . done in a way that does not decrease the number of ports deployed through the Program.[457]

In reply, DTE Electric argues:

> [T]o the extent "future-proofing" as defined by Staff is possible and reasonable, then the Company will do so. When the site host expresses interest in upgrading the equipment to higher-powered charging in the future (e.g., with Electrify America and Tesla), the Company will factor this into the make-ready infrastructure requirements. However, the Company does not

[455] 8 Tr 3615-3616.
[456] Staff's initial brief, p. 107-08.
[457] ChargePoint's initial brief, p. 7.

> agree that it is universally reasonable nor even possible to "future proof" every aspect of an emerging technology. Thus, the Company will not require that all sites be "future-proofed" . . . for a few reasons. First, the Company is trying to balance costs versus deployment, and it wants to ensure the level of investment at each site is appropriate. Oversizing transformers can cause extra losses on the electrical system, and the Company is currently working to reduce these losses . . . . Second, even with higher-powered charging coming to market, the Company believes there will still be a need for the existing DCFC 50 kW infrastructure. For example, there may not be a need for a faster charger in use cases where the EV is parked for thirty minutes or more (e.g., shopping centers, restaurants, etc.). . . . Finally, it could still be a few years before these higher-powered chargers become commercially available on a broader basis. Given the pace of the market and the inability to perfectly predict technology development, the Company does not want to unnecessarily burden utility customers with cost intensive "future-proofing" that is not yet market ready. This is especially true when the Company expects that not all existing charging equipment will be upgraded, but rather that some all-new higher-powered stations will be developed.
>
> Similar to the arguments on the proposed "future proofing" by Staff, the Company will "future-proof" sites as defined by ChargePoint to the extent it is possible and reasonable. The Company will be working closely and cooperatively with site hosts to determine the appropriate balance between future proofing, and the business case for initial deployment of charging stations. Any "future proofing" as defined by ChargePoint, might also require commitments by site hosts for future deployment that site hosts might or might not be willing to enter when DTE Electric deploys the infrastructure.[458]

Based on the evidence and arguments of the parties, and in light of rapidly evolving EV technologies, it is difficult to determine what future-proofing should entail. That being said, as DTE Electric has acknowledged, to the extent future-proofing is possible and reasonable it should be done. As noted by the Staff, DTE Electric should give particular attention to, and investment in, its DCDF sites along travel corridors where, in all likelihood, upgrades will be necessary. It is of some concern that DTE Electric indicates that they plan to future-proof sites "[w]hen the site host expresses interest in upgrading".

[458] DTE Electric's reply brief, pp. 142-43,

It is better that DTE Electric act proactively in future-proofing endeavors, rather than passively responding to site hosts who may or may not be sophisticated enough to understand future-proofing issues. Beyond this, and based on the record presented, it does not appear that the Commission can provide additional guidance, except that future-proofing matters appear ripe for discussion at Staff-sponsored stakeholder meetings.

4. Sale for Resale

The Staff calls for the lifting of DTE Electric tariff prohibitions of sale for resale at publicly available charging stations. Mr. Ozar explained:

> This issue is of importance for two reasons: (a) a per kWh rate is foundational for maturing the competitive market for publicly available . . .charging, as a uniform pricing standard is paramount to the development of robust competition between charging providers; (b) a per kWh rate at publicly available charging stations is needed to create an 'apples to apples' comparison between charging at commercial PEV charging stations and the preferred alternative of charging at home, at night. A direct comparison of PEV charging rates (at publicly available stations) with DTE's time-of-use rates that are stated on a per kWh basis is essential to the transmission of appropriate and transparent price signals . . . . Thus, the prohibition is incongruous to the foundational goals of the Charging Forward program: that managed/controlled charging is the key to obtaining positive grid benefits; that rate design has a dominate role to play in the timing of vehicle charging; and that charging should primarily take place at home, at night. [T]he existing tariff prohibition may actually frustrate such objective[s], particularly if the sale-for-resale prohibition contributes to a persistently high level of "free" charging at publicly available charging stations.[459]

Similarly, Mr. Jester considers limitations on sale for resale "an unnecessary restriction on site host pricing methodology" that will render a site host "unable to charge for charging services based on the amount of electricity transferred to the vehicle."[460] Mr. Baumhefner also recommended that DTE Electric "modify its tariff rules to permit the

[459] 8 Tr 3415-3416:
[460] 6 Tr 2215.

hosts of EV charging stations . . . to price EV charging services on a kilowatt-hour basis, whether the hosts are participants in . . . Charging Forward . . . or not."[461] He added:

> This change . . . promotes several basic policy objectives. First, volumetric, per kilowatt-hour pricing supports price transparency for EV drivers. . . . Moreover, because kilowatt-hour pricing reflects actual energy consumed by an EV and not, for example, the time spent plugged in, it supports pricing that more accurately reflects EV driver's fuel costs. . . .
>
> Finally, per kilowatt-hour pricing allow site hosts to set prices for EV charging that reflect underlying grid conditions and encourage EV drivers to plug in at the right times, like TOU rates. In turn, this better enables site hosts to recover their own electricity costs. Without a tariff modification, site hosts will be unable to pass time-varying price signals on to EV drivers—the people that need to "see" price signals if they are to respond to them. This undermines the Charging Forward program goal to "efficiency integrate EV load" and renders meaningless the Company's commitment to "inform site hosts about …applicable time-of-use rates in order to better inform site host about their options to effectively manage charging load.[462]

Mr. Ellis "encourage[s]" DTE Electric and the Commission "to, at a minimum, remove the tariff-based restriction on sale for resale of electricity for non-utility EV charging station site hosts."[463]

Mr. Serna testified to the Company's opposition to this proposal, stating:

> The Company believes volumetric pricing is an imprecise signal to the customer and is not necessarily correlated with the Company's fixed and demand-based investments. Because of this . . ., the Company would be opposed to modifying its tariff provision to permit per kilowatt pricing. Furthermore, there is a well understood electric regulatory paradigm that must not be upended by engaging multiple independent agents in activities that might be confused with the provision of regulated electric service. Only customers qualifying for DTE Electric's Rider No. 4 ("Resale of Service") may engage in the resale of service under limited circumstances, and those customers who qualify for Resale of Service are obligated to charge the current rates of the utility and otherwise conform to various service requirements.[464]

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[461] 6 Tr 2573.
[462] Id. at 2573-2574.
[463] 7 Tr 3070.
[464] 8 Tr 3617.

The Staff, MEC/NRDC/SC, ELPC, ChargePoint, and EIBC/IEI all express support for eliminating the sale for resale restrictions for EV charging. The Staff argues that DTE Electric's "prohibition on sale for resale at publicly available charging stations frustrates the Company's own stated objective of ensuring that most EV charging load occurs during off-peak hours through enrollment in the Company's TOU rates."[465] EIBC/IEI contends:

> Mr. Jester cautioned that the Commission's policy approach to electric vehicle charging should not assume that Level 2 charging will be free to the driver and that the site host will pay utility costs. Michigan EIBC/IEI supports his recommendation, therefore, to empower site hosts to charge for charging based on electrical usage and modify the Company's tariff to allow sale-for-resale for the purpose of electric vehicle charging.[466]

ELPC argues that "[f]or both ease of customer understanding of what they pay, and for parties to gain knowledge from the pilot, the Commission should change the tariff to allow charging station owners to price per kWh."[467]

DTE Electric opposes this proposal for a number of reasons. First, DTE Electric argues that volumetric pricing is an imprecise signal to the customer and does not necessarily reflect the company's fixed and demand-based investments. In addition, DTE Electric contends that "allowing site hosts to charge services by the kilowatt-hour could create confusion for customers . . . as the rates to be offered . . . would not be regulated by the Commission and could be quite different than those offered by the utility.[468]

[465] Staff's initial brief, pp. 108-09.
[466] EIBC/IEI initial brief, p. 44.
[467] ELPC's initial brief, p. 25-26.
[468] DTE Electric's reply brief, p. 137.

However, DTE Electric goes on to reveal what appears to be its primary concern; maintaining control of electric sales:

> There is also a well-understood electric regulatory paradigm that must not be upended by engaging multiple independent agents in activities that might be confused with the provision of regulated electric service. Only customers qualifying for DTE Electric's Rider No. 4 ("Resale of Service") may engage in the resale of service under limited circumstances, and those customers who qualify for Resale of Service are obligated to charge the current rates of the utility and otherwise conform to various service requirements.
>
> DTE Electric has proposed the EV program its management believes is appropriate. 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).
>
> DTE Electric appreciates the input and collaboration regarding EV service but does not wish to implement proposals involving per kWh pricing for EV charging. It bears emphasis that the proposals to remove the "sale-for-resale" provision are contrary to the fundamental business structure that the Company envisioned for the Charging Forward program. The Company does not agree to such proposals, and the Commission should not order the changes set forth in these proposals.[469]

MEC/NRDC/SC provides a well-reasoned response to DTE Electric's position, which is extensively reproduced, below:

> Today, the Company's tariff rules only permit "the provision of EV charging services for which there is no direct per kWh charge." This restriction should be lifted to allow the hosts of EV charging stations to price EV charging

[469] DTE Electric's reply brief, pp. 138-139.

> services on a kilowatt-hour basis, whether the hosts are participants in DTE's Charging Forward program or not. . . .
>
> DTE protests that this change would "upend" a "well-understood regulatory paradigm." In reality, this minor change would harmonize the regulatory treatment of hosts of EV charging stations in DTE's service territory with those in Consumer's. In Case No. U-17990, a similar tariff change was asked for by Staff, MEC, NRDC, Sierra Club, Environmental Law & Policy Center, and ChargePoint. That request was met with support by Consumers Energy. In its Order, the Commission found that
>
> > The proposal indeed appears to be non-controversial, and the Commission agrees with the Staff that the sale of electricity by charging station owners should not be treated as a resale of electricity under the tariff, or as a sale by regulated utilities. This is a necessary change to the tariff language which the Commission approves.
>
> The Commission should reach the same conclusion here for several reasons. First, volumetric, per kilowatt-hour pricing supports price transparency for EV drivers. The kilowatt-hour is the common and familiar metric for electricity consumption. Moreover, because kilowatt-hour pricing reflects actual energy consumed by an EV and not, for example, the time spent plugged in, it supports pricing that more accurately reflects EV driver's fuel costs.
>
> Finally, per kilowatt-hour pricing allows site hosts to set prices for EV charging that reflect grid conditions and encourage EV drivers to plug in at the right times. In turn, this better enables site hosts to recover their own electricity costs. The Company's contrary suggestion that "volumetric pricing is an imprecise signal" that doesn't relate to system conditions cannot be squared with reality. Indeed, without a tariff modification, site hosts will be unable to pass time-varying price signals on to EV drivers—the very party that needs to "see" price signals if they are to respond to them. Maintaining the current tariff prohibition would undermine the Charging Forward program's goal to "efficiently integrate EV load" and render meaningless the Company's commitment to "inform site hosts about …applicable time-of-use rates in order to better inform site host about their options to effectively manage charging load." It would also leave conflicting regulatory policy across the state unresolved. The Commission should order this change.

The Staff's and Intervenor's evidentiary presentations and arguments on this issue are convincing. A properly structured EV program must free site hosts from the confines of DTE Electric's sale-for-resale prohibition. In short, DTE Electric's proposal to retain its sale-for-resale prohibition would remove a valuable tool from Charging Forward's toolbox of pilot program options that should be available to site hosts and DTE Electric. The reasons for this conclusion are numerous and nicely summarized by MEC/NRDC/SC, quoted above, and will not be repeated. Lifting DTE Electric's sale-for-resale prohibition is necessary if DTE Electric wishes to properly explore and learn how to best manage the demands of the electrification of the automobile sector.[470]

DTE Electric argues that Commission approval of proposals to remove sale-for-resale prohibitions from DTE Electric's tariffs represents a Commission over-reach. Citing *Union Carbide,* DTE Electric argues that it "has proposed the EV program its management believes is appropriate", that it does not agree to such proposals, and the Commission "should not order the changes set forth in these proposals."[471] DTE Electric's argument and its reliance on *Union* Carbide is not convincing. In Union Carbide, the Commission was found to have exceeded its authority when it ordered Consumers Energy to cease operation of its Karn units No. 3 and No. 4 out of economic order.[472] However, the same court also found that the Commission was within its authority to regulate to enforce reasonable rates and charges and that it may prevent the passing through to customers of any unreasonably incurred expense.[473] In this case, the Commission is called upon to amend a DTE Electric tariff provision that Staff and

[470] As noted by Chargepoint witness James Ellis, the "EV charging market is growing and dynamic, and site hosts are best positioned to create value for EV drivers". 7 Tr 3045. He notes, as examples, that site hosts might choose to offer free charging sessions, fixed price sessions, hourly prices, sales based on a per kilowatt-hour price, TOU prices, length-of-stay prices charged during the first hour or two with higher prices for every hour thereafter, minimum and/or a maximum prices per session, a combination of the above, and driver group prices. 7 Tr 3046.
[471] DTE Electric's reply brief, pp. 138-39.
[472] *Union Carbide* at 148-49
[473] *Union Carbide* at 149

Intervenors find unreasonable. Pursuant to *Union Carbide*, the Commission has full authority to grant that request.

Further, it is noted, that the Charging Forward program finds wide and enthusiastic support from various parties to this case and, it is expected, from the Commission. Charging Forward is a program to lay the ground work for, and to develop knowledge about, the inevitable electrification of vehicular travel and the corresponding demands on our utility industry. Throughout this educational and transformational process, DTE Electric should expect that enthusiastic support to continue. However, DTE Electric is reminded that that cost recovery is limited to expenditures that are reasonable and prudent. As DTE Electric moves forward to meet the demands of the swiftly emerging and changing EV technologies, it is anticipated that not all of its endeavors will proceed flawlessly and prove fruitful; that is to be expected. Under Charging Forward, it is anticipated that some pilot programs may produce limited rewards and, none the less, find enthusiastic Commission support for full cost recovery in rates. However, for pilot programs that the Commission finds problematic from the inception, and for which DTE Electric proceeds regardless of the Commission's concerns, DTE Electric should expect much less enthusiasm from the Commission when cost recovery for those pilots is requested.

For the reasons stated above, DTE Electric should be directed to file amended tariffs to permit sale-for-resale for commercial EV charging site hosts.

5. <u>Demand Charges</u>

Mr. Jester testified to MEC/NRDC/SC's concern regarding demand charges for DCFCs. Mr. Jester stated:

> [DTE Electric] has not addressed the problem of demand charges for direct current fast chargers. Until electric vehicle penetration builds up so that a DCFC station is used steadily throughout each day, applying a demand charge can cause the site host to incur very high costs per unit of vehicle charging . . . . For example, assume that a typical charging session at a DCFC station is at the rate of 80 kW and is 60 kWh . . . . If the charging is done under DTE's Rate Schedule D4, with rates as proposed in the present case, then the monthly demand charges associated with the DCFC station will be about $2,589. The kWh charge to the site host will be 3.919 cents per kWh for the first 200 kWh per month and 2.919 cents per kWh thereafter. A 60 kWh charge at 3.919 cents per kWh will cost $2.35, while a 60 kWh charge at 2.919 cents per kWh will cost $1.75. One such charging event per day for a month would cost about $55 for energy charges and $2,589 for demand charges, for an average cost per kWh of about $1.47. Two such charging events per day would cost about $110 for energy charges, $2,589 for demand charges, and thus an average cost per kWh of about $0.75. Put another way, a DCFC site host subject to a demand charge risks an immediate demand charge obligation of more than $30,000 per year if they attract one charging session per month, unless they have substantial on-site load diversity and can manage the timing of charging events in relation to other on-site loads. If site hosts use fast chargers at 150 kW or 350 kW that will be convenient for highway travelers, this situation will be even worse. . . . I strongly recommend that the Commission ensure that for the next several years, DCFCs have access to a tariff without a demand charge or cap the demand charge at a ratio to energy delivery consistent with a more mature market, such as limited billable demand to not more than energy divided by 180 (corresponding to 6 hours per day 13 charger usage).[474]

Mr. Krause testified that during EV's "early adoption phase there may be merit to having a demand charge holiday." Mr. Krause adds:

> If the Commission were to order a demand charge holiday, Staff would recommend that the Commission be specific about the holiday and not make it permanent. For example, the Commission could establish a DCFC tariff based on the underlying standard rate that has no demand charges for the next 2-5 years . . . . Staff does not support capping the demand charge ratio as suggested by [Mr. Jester].
>
> Staff also points out that half of DTE's current DCFC customers are on rate D3 which includes no demand charges. While rate D3 is limited to a load of 1000 kW (or possibly slightly more, according to the tariff) it should be within the charging company's abilities to communicate between chargers

[474] 6 Tr 2216-2217,

> at a location to limit the site load to 1000 kW. For example, take a hypothetical site with a 350kW charger and four ports. If three ports were in use simultaneously, the chargers could limit themselves to 333 kW each, and if all four were in use, the chargers could limit to 250 kW each.[475]

In response to this concern, Mr. Serna, testified:

> Commercial customers today can choose between any of the following available rates: the D3 General Service Rate, the D3.3 Interruptible General Service Rate, the D4 Large General Service Rate, and the D1.9 Experimental Electric Vehicle Rate (separately metered time-of-use rate). The D3 General Service Rate is a commercial rate without demand charges, so we expect most fast charging station owners will opt for this rate. However, it is up to the customer to decide what is the best rate structure option.

The Staff supports a Demand Charge holiday as proposed in its rebuttal testimony.

EIBC/IEI argues that:

> While the Company on rebuttal admits that the D1.9 Experimental Electric Vehicle Rate has a demand charge (separately metered time-of-use rate), it states that it "expects most fast charging station owners will opt for" the D3 General Service Rate. 8 Tr 3624. It seems counter-intuitive for the Company to include a demand charge in its EV tariffed rate, but then claim that it "expects" customers to choose a non-EV rate for its EV service. For all of these reasons, Michigan EIBC/IEI supports Mr. Jester's recommendation that the Commission ensure that for the next several years, DCFCs have access to an EV tariff without a demand charge. Or, in the alternative, that a cap be placed on the demand charge at a ratio to energy delivery consistent with a more mature market, such as limited billable demand to not more than energy divided by 180 (corresponding to 6 hours per day charger usage).[476]

Citing Mr. Jester's testimony, EIBC/IEI recommends that, "for the next several years", the Commission should ensure DCFC site hosts have access to EV tariffs without a demand charge.[477] "ChargePoint agrees that demand charges can pose a considerable burden

[475] 8 Tr 4254-4255.
[476] EIBC/IEI's initial brief, p.43.
[477] EIBC/IEI's reply brief, p. 10.

on site hosts seeking to deploy DC fast chargers."[478]

DTE Electric dismisses this issue as "moot", arguing that:

> [C]ommercial customers can already choose from any of the following available rates: the D3 General Service Rate, the D3.3 Interruptible General Service Rate, the D4 Large General Service Rate, and the D1.9 Experimental Electric Vehicle Rate (separately metered time-of-use rate). The D3 General Service Rate is a commercial rate without demand charges . . . . However, it is up to the customer to decide what is the best rate structure option. Thus, the Company believes that the issue of a demand charge . . . does not need to be addressed with any additional requirement.[479]

DTE Electric's position on this issue is unpersuasive. As established by the record, during the initial stages of EV infrastructure development, demand charges pose a significant and unnecessary economic impediment to the successful deployment of publicly available DCDF charging stations. Further, the incongruity of DTE Electric's proposed D1.9 Experimental Electric Vehicle Rate, which has a demand charge, and DTE Electric's D3 General Service Rate, which does not have a demand charge, is hard to reconcile. Therefore, based on the record presented, it is recommended that the Commission adopt Staff's proposal for a demand charge holiday, for EV site hosts, to be offered by DTE Electric for up to five years.

6. <u>DCFC Price Regulation</u>

Mr. Jester, noted that "during the early years of electric vehicle infrastructure development, most DCFC locations will have a local monopoly." He further testified that "[t]here will not be enough fast charging locations that a traveler can choose which to use

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[478] ChargePoint's reply brief, p. 13.
[479] DTE Electric's reply brief, p. 146.

based on price, but instead they will have to use what is available to ensure trip continuity.[480] To address this market failure, Mr. Jester recommended:

> While I do not think that the Commission should regulate fast charging in the long run, the Commission should consider providing some level of consumer protection as a condition of participation in the Company's DCFC rebate program. In U-20134, Consumers Energy indicates that "since there are currently a limited number of DCFCs in Michigan, the Company will work closely with site hosts to ensure prices charged to EV drivers are within market rates." If such a pricing limitation is established prior to a site host accepting the rebate, it will be fair to the site host. A reasonable standard for this purpose would be to limit the total cost per charging session at a rebated DCFC to roughly the cost of gasoline providing equivalent mileage. . . . Such a price limitation could be for a finite number of years or could be a condition for access to a tariff without a demand charge.[481]

Mr. Krause testified that the Staff recommends that vehicle charging service that should be unregulated by the Commission. According to Mr. Krause, the Staff fears that "[i]f the Commission begins regulating charging service it may be hard to stop regulating this service in the future." Additionally, the Staff considers DCFC to be a "premium service" that "should likely cost more than level 2 charging". The Staff's concerns are that "charging too little" for the service "will result in a demand for it that is too high" and that "intentionally setting too low a price for DCFC will be detrimental to the utilization of the system."[482]

ChargePoint's witness, Mr. Ellis, somewhat obliquely addressed these regulatory proposals:

> [S]ite hosts of publicly available charging stations should have the discretion to determine pricing for EV charging services. Site hosts have visibility into their parking lots and can best manage access and pricing to optimize the charging asset utilization. Without site host pricing flexibility, EV drivers chose to leave their vehicles parked dormant for hours, thereby prohibiting

[480] 6 Tr 2217.
[481] 6 Tr 2217-18,
[482] 8 Tr 4254-4256.

> any other EV driver in need of a charge to use the asset, as there would be no incentive to leave once charging is complete.[483]

More pointedly, however, he added:

> Participating site hosts must have confidence that they will have the flexibility to make the best operating decisions related to EV charging stations deployed on their premises, including pricing to drivers. Artificial “caps” or regulation on the driver pricing would serve as a disincentive for expanded investment by commercial site hosts, which would not be in the public interest.[484]

MEC argues for adoption of the same consumer protection measures that were approved in the settlement agreement in Case No. U-20134:

> As a solution, Mr. Jester points to Consumers Energy’s approach in PowerMIDrive, which recognizes that “since there are currently a limited number of DCFCs in Michigan, the Company will work closely with site hosts to ensure prices charged to EV drivers are within market rates.” MEC/NRDC/SC/EC urge the Commission to direct DTE to adopt this common-sense solution as well as the default pass-through of time-of-use rates. These reasonable terms for participation in a voluntary program are crucial to deliver the benefits of load management and fuel cost savings, and to protect consumers and utility customer dollars.[485]

EIBC/IEI supports Mr. Jester's recommendation that the total cost per charging session at a rebated DCFC be limited to roughly the cost of gasoline providing equivalent mileage.[486]

Conversely, the Staff recommends that tying fast charging rates to the price of gasoline be rejected.[487] DTE Electric states that while it agrees with the concept of reasonableness for DCFC charging and that the company should work to ensure that the cost per charge is within market rates:

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[483] 7 Tr 3065-3066.
[484] Id. at 3066-67
[485] MEC/NRDC/SC/s initial brief, p. 87.
[486] EIBC/IEI’s initial brief, p. 44.
[487] Staff’s initial brief, p. 130.

> [T]he Company disagrees to the extent MEC/NRDC/SC suggest that the Commission should establish a specific standard. The Company has indicated that through a collaborative approach with site hosts it will be able to positively influence the reasonable delivery of EV charging services. The Company will educate site hosts on acceptable pricing structures and track the price site hosts "charge for charging" and will aim to identify any outliers and find ways to collaborate to address the situation. At this early stage in market development, the Company does not see the need to begin to impose specific standards, especially as there is no evidence that supports their imposition. Through its annual reports, the Company will provide updates to the Commission and to the extent it feels there is a need to impose a standard, it will propose one at that time.[488]

There can be no doubt that until the commercial charging market reasonably develops, there needs to be some sort of assurance that those few subsidized site hosts will not engage in unreasonable pricing tactics. However, the Staff has expressed its disinterest in providing price regulation and loosely tying electric prices to the price gasoline is not reasonable. Considering the record presented on this issue, MEC/NRDC/SC provides the most reasonable solution that has the advantage of providing consistent policies for the two largest utilities in Michigan. Therefore, this PFD recommends that the Commission direct DTE Electric to engage in the same consumer protection measures as were approved in the Consumer's settlement.

7. <u>Level 2 Charger Metering Options</u>

Mr. Ozar recommended additional tariff provisions to permit AMI submetering behind a customer's existing billing meter and/or "vehicle on-board metering and communication" or "smart/connected chargers" to separately measure PEV charging load; the costs of such options to be covered by the program.[489]

Mr. Serna testified to DTE Electric's opposition to this recommendation, stating

[488] DTE Electric's reply brief, p. 139.
[489] 8 Tr 3417-18.

that the company "needs more time to evaluate the accuracy, security, and cost effectiveness of all available submetering options prior to piloting one of the available technologies[,]" adding that DTE Electric promises continued investigation into these options and future recommendations in an annual status report.[490]

The Staff recommends the addition of two submetering options under Rate Schedule D1.9; "AMI submetering behind a customer's existing billing meter to separately measure EV charging load" and provisions to "allow for the piloting of novel approaches to bill customers using non-utility owned submetering technologies such as vehicle on-board metering and communication or smart/connected chargers." The Staff contends its submetering proposal will reduce installation costs, will permit residential customers to be billed separately for EV charging under a TOU rate, and is similar to the approach already approved for Indiana Michigan Power.[491]

As for its recommended pilot program, the Staff argues that it would allow access to EV TOU pricing to tenants of MUDs and would facilitate building owners ability to pass-through TOU rates to their tenants. The Staff adds:

> This tariff fix is needed before the Company implements the program, not after. With substantive, but generic language additions to Rate Schedule D1.9, the Company would be granted the flexibility to explore a wide range of "separately-metered" options that are not now possible to pilot. At this time, Staff is not recommending any particular amendatory language to be included in the recommended filing. However, the tariff language should include a waiver of availability (i.e. at the company's discretion) similar to Staff's recommendation for amendment of the Company's rules relating to Contributions in Aid of Construction.[492]

[490] 8 Tr 3618-19.
[491] Staff's initial brief, p. 110.
[492] Staff's initial brief, pp. 111-112.

The Staff considers these issues “fundamental to approval of the proposed Charging Forward Program, as metering barriers impede residential enrollment in the Experimental Electric Vehicle Rate, and market barriers in the MUD market result in it being underserved.”[493]

In response, DTE Electric states that it “agrees that this is an important element that needs to be explored, but . . . that it would be premature to include it in Charging Forward, adding:

> The Company needs more time to evaluate the accuracy, security, and cost-effectiveness of all available submetering options prior to deploying one of the available technologies. The Company is aware of several utilities already piloting different submetering options (including AMI submetering), thus it believes it can leverage learnings from those pilots to inform its future approach. Furthermore, . . . billing and metering systems would need to be enhanced to enable such an option for customers. To ensure the proper billing and metering of that load using AMI data, appropriate planning and testing would need to be undertaken, thus any expectation that such a change could be implemented [before the Charging Forward program begins] is not practical, desirable nor feasible. The Company will continue to investigate the available options to achieve the goals of enabling the use of the Company’s D1.9 rate without the use of the second meter. When sufficient information is obtained and well understood, the Company will present a recommendation in one of the annual status reports of the Charging Forward program. [494]

As noted above, DTE Electric recognizes the Staff’s proposal as an important metering option; one that it intends to research further. However, DTE Electric’s opposition to the Staff’s proposal appears to be based upon a misunderstanding of Staff’s request. In its briefing, the Staff makes clear that it is not suggesting DTE Electric must provide its customers these metering options, but, instead, is merely proposing to make it an option, at DTE Electric’s discretion. Staff contends, that to add this option to DTE

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[493] Id. at 113.
[494] DTE Electric’s reply brief, pp. 145-46,

Electric's toolbox, the tariffs need modification.

Staff's position is convincing. Therefore, it is recommended that the Commission order DTE Electric to provide tariff amendments to permit, at the company's discretion, the advanced metering options proposed by Staff.

8. Reporting Requirements and Technical Conferences

The Staff recommended additional reporting requirements that include a status report prior to program implementation and annual reports, thereafter. The Staff proposed that, throughout the course of the three-year program, it will convene technical conferences with intervenors and stakeholders after each filing.[495]

DTE Electric supports the Staff's recommendation of annual reporting and plans for technical conferences, but not Staff's recommended status report; arguing that, instead, the record in this case is sufficient.[496]

Mr. Ellis proposed a Program Advisory Council (PAC) "to help guide material decisions and actions regarding Program design and implementation." Mr. Ellis envisions an advisory council having an array of members representing the Staff, consumers, environmental stakeholders, EV drivers, the automotive industry, disadvantaged communities, labor, and EV charging partners.[497]

Mr. Jester states that "the Commission should require the Company to monitor and report on its success in providing electric vehicle infrastructure and electric vehicle use for low income communities."[498] Mr. Baumhefner, testified that DTE Electric should report

[495] 8 Tr 3420.
[496] 8 Tr 3619-20.
[497] 7 Tr 3056.
[498] 6 Tr 2221.

aggregated load profile data for the different TOU tariff groups to allow for comparison of the effects of differing pricing options on customer behavior.[499]

The Staff argues that, "because the current Charging Forward Program is largely conceptual . . . Staff recommends that the Commission direct the Company to file a status report prior to program implementation and annual reports thereafter." In addition, Staff "intends to convene a technical conference with the Company, intervenors and interested stakeholders to obtain public awareness and input."[500]

Chargepoint reiterates its support for a PAC, quoting Mr. Ellis's testimony. MEC/NRDC/SC supports the Staff's proposal for annual reporting and the convening of a technical conference. Further, MEC/NRDC/SC supports ChargePoint's proposal for an advisory council to review and provide guidance of the Charging Forward Program.[501] EIBC/IEI recommends that, to encourage universal availability of charging services, "the Commission should require the Company to monitor and report on its success in providing electric vehicle infrastructure and electric vehicle use for low income communities."[502] EIBC/IEI supports the formation of a technical conference.

DTE Electric agrees to "[p]rovide more regular reporting and file summary reports on an annual basis," and to convene a stakeholder technical conference "to improve public awareness and obtain input."[503] DTE Electric opposes ChargePoint's PAC considering it duplicative of other efforts that are current underway and that are expected to continue.[504]

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[499] 6 Tr 2567.
[500] Staff's initial brief, pp.113-114.
[501] MEC /NRDC/SC's reply brief, pp. 31-32.
[502] EIBC/IEI's initial brief, p. 47.
[503] DTE Electric's reply brief, p 133.
[504] DTE Electric's reply brief, p 147.

The Staff's arguments on this matter are persuasive. As noted, Charging Forward is largely conceptual, based, in part, on delayed pilot programs that where slated for 2018. Therefore, this PFD recommends that the Commission direct DTE Electric to prepare and file a status report, prior to program implementation, so that all stakeholders and the Commission will be apprised of the scope and nature of this as yet undeveloped program. Further, as DTE Electric has agreed to do, the Commission should direct the preparation and filing of annual reports, thereafter.

The Staff's proposal to host technical conferences with the company, intervenors, and interested stakeholders appears essential to the success of the program. If carefully structured, implemented, and modified on the basis of feedback from the various pilots, Charging Forward has the potential to provide vital information to DTE Electric and the Commission. Further, it is hoped that the program's capital investments will lay the foundation upon which EV usage can more naturally expand.

It is noted that, as proposed, DTE Electric has placed management of Charging Forward in the hands of only two individuals. Given, the numerous pilots and amount of information that is expected to be gathered, management of the program by two persons appears to be a tall task. Therefore, it is recommended that the Commission direct Staff and DTE Electric to work frequently and closely together with stakeholders, intervenors, and other interested parties, such as those mentioned by ChargePoint, within the framework of technical conferences. Given the rapid change in EV technology and the limited FTE's that DTE Electric has assigned to this program, incorporating the skills and knowledge of non-utility experts seems critical to the program's success. The purpose of these technical conference should be to help guide DTE Electric with the numerous decisions and actions required for Program design and implementation. Further, as has been mentioned by a number of parties, DTE Electric should report its actions and findings regarding the provision of services to low income communities and multiple unit developments.

9. Increased Budget

Mr. Ozar recommended an expansion of the Charging Forward program in the amount of $6 million “to meet additional ‘controlled charging’ objectives and solidify market transformation with increased available capital (in the form of rebates/interconnection assets).” Further, he testified that additional funding is needed to finance an expanded school bus pilot program.[505]

Similarly, after presenting evidence to show that, as proposed, Charging Forward will leave a major infrastructure gap in the DCFC market,[506] Mr. Jester recommends that the Commission “not cap either the number of DCFCs to be supported nor the total spending on this component of the program”, explaining:

> Rather the Commission should endorse the objective of providing a sufficient network of DCFCs in the Company’s service territory and authorize the Company to spend as much on this component as is prudently necessary to achieve that objective. The Commission can reasonably require the Company to file its detailed plan for this Component when it is prepared and provide an opportunity for public and stakeholder comment to inform the Company’s prudence before the spending is done. The Commission should consider linking the filing of such a plan by the Company to the related study sponsored by the Michigan Agency for Energy that is currently underway.[507]

[505] 8 Tr 3409-3413.
[506] DCFC chargers are critical to EV adoption as they provide quick recharging along highway corridors, thus facilitating long-distance travel and alleviating “range anxiety”. 6 Tr 2212-14.
[507] 6 Tr 2214.

Mr. Baumhefner, testified that DTE Electric “is targeting several priority segments and various different categories of vehicles, which is commendable.” “However”, he continues, “the size of the corresponding budget may need to be increased to allow for meaningful participation in the pilot by all those different market segments and vehicle categories.”[508] Mr. Ellis recommend an increase to the Program’s budget to cover future-proofing costs.[509]

Mr. Serna indicated that he didn’t support increased funding, testifying that DTE Electric “believes it is premature to increase funding and prefers to ensure it has implemented a successful program before it proposes increases in scope and budget to Charging Forward.”[510]

In part, the Staff recommends approval of $6 million in additional funding for Charging Forward for costs associated with an expanded school bus pilot and the inclusion of an 80A charging pilot for medium/heavy duty vehicles.[511] Further, noting “that seven of the Company’s pilots that were intended to support the Charging Forward Program are significantly delayed”, Staff proposes that the unfunded cost of these pilots, “which are implemented after the order in this case”, “be included in the program for cost recovery via the regulatory asset.” [512]

EIBC/IEI argues that the Commission should not cap the number of DCFCs to be supported by the program, but, rather, “the Commission should endorse the objective of providing a sufficient network of DCFCs in DTE Electric's service territory.” With this goal

[508] 6 Tr 2566.
[509] 7 Tr 3057.
[510] 8 Tr 3613.
[511] Staff brief, p. 107.
[512] Staff’s initial brief, pp.107, 116.

in mind, EIBC/IEI argues that the Commission should "authorize DTE Electric to spend as much on this component as is prudently necessary to achieve that objective."[513]

DTE Electric argues that it's "premature to increase funding", adding:

> [DTE Electric] prefers to ensure it is on target to implement a successful program before it proposes increases in scope and budget to Charging Forward. The structure and budget for the Charging Forward program was carefully planned and the Company has not assessed the requirements related to the many pilots Staff (and other parties) have suggested. As such, the Company does not have any basis to determine whether the incremental $6 million in budget is adequate or not.[514]

However, DTE Electric agrees to include "costs related to any delayed 2018 EV pilots . . . in the Charging Forward program for purposes of cost recovery."[515]

The transformation of Michigan's motor vehicle sector to EVs appears imminent and of great importance to the State's economy and environment. Currently, however, the State's EV infrastructure is woefully underdeveloped and stands as an impediment to the widespread adoption of this emerging technology. Charging Forward is DTE Electric's first real attempt to prepare itself for the demands of vehicular electrification. Properly funding this program is, therefore, of utmost importance.

As discussed above, this PFD recommends that the Charging Forward program be expanded in scope in several significant ways. For example, it is anticipated that an expanded school bus pilot will add cost, the amount yet to be determined. It is possible that removal of rebate caps could also add costs. Additionally, to establish a minimum network of corridor chargers, DTE Electric may need more than the 32 DCFC that it proposes. Also, DTE Electric indicates that it will be rolling in the costs of its delayed

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513 EIBC/IEI's reply brief, pp. 9-10.
514 DTE Electric reply brief, p 140.
515 DTE Electric's reply brief, p. 133.

2018 EV pilots. And, finally, DTE Electric may find that it has underestimated the human resources it will need committed to the program and the large undertaking it represents. In sum, there is sufficient evidentiary support to conclude additional funding will likely be needed to make Charging Forward the success all parties to this case hope for and the Michigan citizenry needs. Therefore, based on the evidentiary record and the arguments presented, it is recommended that Staff's proposal to increase the Charging Forward budget by $6 million be adopted.

10. Cost Recovery

The cost recovery debate in this matter primarily consists of Staff's and DTE Electric's competing proposals. Mr. Ozar testified:

> Staff recommends that recovery of program-related Operations and Maintenance (O&M) and 'make-ready' rebates for customer or third-party owned/operated Electric Vehicle (EV) charging infrastructure (downstream of the meter) be deferred and recovered through regulatory asset accounting, with return. Deferred recovery through regulatory asset accounting will require a prudency review of actual expenditures prior to inclusion in rate base. Additionally, Staff recommends that utility infrastructure (Capex) related to interconnection of EV charging stations, being directly related to customer uptake of program offerings and intrinsically tied to site-specific characteristics, mimic the regulatory asset treatment of "make-ready" rebates, and be recovered in future rate cases as an increase in rate base.[516]

The Staff argues that, consistent with the Commission's order in Consumers Energy's most recent electric rate case, Case No. U-20134, it proposes that, for Charging Forward costs, the Commission "authorize a regulatory asset to recognize the deferred costs in account 182.3, Other Regulatory Assets, with a five-year amortization beginning the year following the deferral of costs to the regulatory asset account", with "allowance

[516] 8 Tr 3410.

in rate base and expense after a prudency review occurs in the Company's next rate case."[517]

In response, Mr. Serna testified:

> The Company supports [treatment of] costs related to capital expenditures above the capital reflected in this case as a regulatory asset. The Company's understanding is the deferred capital related costs will include a return, depreciation, property taxes and incremental O&M (if any). Company Witness Uzenski addresses the regulatory asset cost recovery timing in her rebuttal testimony. However, the Company requests program-related O&M, consisting of EV Education & Outreach and program management, be recovered as base O&M.[518]

DTE Electric agrees with Staff's position to give Charging Forward O&M expense regulatory asset treatment with amortization over five years. However, DTE Electric disagrees with Staff's proposals to begin amortization the year after the costs are incurred, to delay recovery of the unamortized balance until after Staff's review, and to include capital expenditures in the regulatory asset.[519]

DTE Electric explains and argues that it "would lose recovery of deferred costs that are amortized without the expense being included in the revenue requirement", adding that, "[i]f the Commission approves the proposed IRM, then DTE Electric might not file another rate case for a few years. Therefore, a portion of the deferred costs will be amortized but never recovered." DTE Electric agrees that a prudency review by Staff is appropriate but depending on the timing of future rate cases and Staff's reviews, recovery of the deferred costs could be significantly delayed.[520]

Staff acknowledges "that some costs may not be recovered due to regulatory lag,"

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[517] Staff's initial brief, pp. 117-18.
[518] 8 Tr 3614.
[519] DTE Electric's reply brief, pp. 133-34.
[520] Id. at 134-135.

but argues that, depending on the timing of [521]DTE Electric's rate cases, "the Company could also over-recover some of these costs." DTE agrees with this analysis.[522]

As a whole, Staff argues that its recommendation "is a prudent measure to guard against ratepayers paying for costs which are projected but may not be incurred, while at the same time allowing the Company an opportunity to recover actual incurred costs as part of future rate cases. Conversely, DTE Electric argues that "Staff's proposed accounting is a disincentive for the Company to aggressively implement the Charging Forward program".[523]

ELPC opposes "regulatory treatment of the rebate as an asset for DTE for the same reasons put forth in the Consumers case.[524] ELPC considers the rebates an expense not a regulatory asset.[525] However, at ELPC Br, p 24-25, ELPC argues that, "[a]ssuming the Commission reaches the same conclusion it reached in Case No. U-20134", the Commission's should add the following to its order:

> The Commission directs [DTE Electric], at the conclusion of the pilot program, to examine whether there would be cost savings associated with the use of a tracker for future rebate programs (with O&M treatment) in comparison to regulatory asset accounting.

MEC considers DTE Electric's cost recovery plan to be reasonable.[526]

The cost recover issues, presented here, closely parallel those recently considered and decided by the Commission in Consumers Energy's most recent rate case, Case No. U-20134. In fact, Staff proposes that the Commission adopt the same cost recovery

[521] Staff's initial brief, pp. 118-19.
[522] Staff's initial brief, p. 118; DTE Electric's reply brief, p. 134.
[523] DTE Electric's reply brief, pp. 135-36.
[524] ELPC brief, p. 24.
[525] ELPC brief, p. 24.
[526] MEC brief, p. 89.

mechanism for DTE Electric's Charging Forward program as it did on January 9, 2019 for Consumers Energy corresponding PowerMIDrive program. In that Case, at U-20134, Order, p 5, (citations omitted), the Commission summarized the cost recovery proposal for Consumers Energy's PowerMIDrive program, as follows:

> [T]he utility would amortize each annual deferred amount over [five] years beginning the year after the cost is incurred, the resulting expense would be included in rates, and the deferred cost would be subject to review in rate cases. The deferred unamortized balance would be included in rate base and would earn a return. . . . Consumers requests that the Commission: (1) authorize the recognition of a regulatory asset to recognize deferred EV program costs; (2) authorize the amortization of deferred EV program costs over five years beginning the year after the cost are incurred; (3) include recovery of the resulting amortization expense in rates; and (4) include the deferred net unamortized balance of EV program costs in rate base.

In the case at bar, considered in whole, and recognizing the uncertainty of Charging Forward's actual costs, the Commission finds Staff's proposal most reasonable. As Staff argues, it protects customers from paying for costs that might not be incurred and provides DTE Electric to fairly recover its costs actually incurred. This is particularly important considering DTE Electric's track record of slow EV pilot program implementation. Additionally, it has the added benefit of being consistence with the EV provisions of the Commission's January 9th orders in Case No. U-20134. Therefore, it is recommended that the Commission approve the regulatory asset treatment of Charging Forward deferred costs, with a five-year amortization beginning the year following cost deferral, and allowance in rate base and expense after a prudency review in future DTE Electric rate cases. And, as it did in the Consumers Energy case, it is recommended that the Commission direct DTE Electric to examine whether there would be cost savings realized by use of a tracker for future rebate programs.

B. Infrastructure Recovery Mechanism

DTE Electric proposed an IRM to recover the incremental revenue requirement associated with certain distribution, fossil generation and nuclear generation capital expenditures through 2022, through an IRM surcharge beginning in 2020. The proposed incremental revenue requirement to be recovered through the IRM is $137.4 million in 2020, $268.9 million in 2021, and in 2022, the proposed incremental revenue requirement is $417.6 million.[527] Mr. Stanczak, Mr. Bruzzano, Mr. Davis, and Mr. Paul, testified that the company' proposal is reasonable and should be approved in this proceeding. Mr. Stanczak testified that the IRM will reduce costs for all parties because the company may be able to defer filing a rate case until after 2022. Even if it does file a rate case, it will be much smaller than what would likely occur without an IRM.[528]

Although DTE Electric proposes flexibility of spending within broad categories (distribution, generation, and NGCC plant), spending amounts will not be reallocated between or among these classifications.)

Ms. Uzenski summarized the capital proposed to be covered by the IRM, and Mr. Slater addressed the revenue requirement associated with the proposed IRM capital expenditures through 2022. Finally, Mr. Bloch addressed the rate design and proposed rates associated with the IRM. DTE Electric believes that with the proper IRM in place for the intervening years, it may be able to defer filing a rate case until sometime in 2022

[527] Exhibit A-30 Schedule T-10.
[528] 3 Tr 74-75.

for new base rates in 2023. DTE Electric points to its main replacement program (MRP), and meter move out (MMO) pipeline integrity (PI) programs, which were approved by the Commission, affirmed by the Court of Appeals, and expanded over time, as substantially similar to the IRM proposed here.[529]

Seven of the other parties object for various reasons to the company's proposed IRM. Mr. Laruwe testified that there is value to the implementation of IRM for multi-year rate plans to address known system concerns and modernization. However, the scope of the proposed IRM in this case exceeds investments for compliance and safety, and it needs to be approached in a more cautious manner to ensure all potential benefits are realized. Mr. Laruwe testified that the Staff would like to see clear public policy and performance goals at the onset of the investment necessary for an IRM. In addition, Mr. Laruwe testified that is was not clear what value (improved customer service, improved customer satisfaction, improved reliability, etc.) will accrue if the Commission were to approve the IRM. But ratepayers would have guaranteed rate increases during the IRM period.

The Staff argues that although DTE Electric claims the proposed IRM will also minimize regulatory burden, without a clear commitment to not file a rate case during the IRM, there could be an IRM reconciliations and rate cases going on concurrently in the future. This would result in a significantly increased burden to all parties.

The Staff also points out that this proceeding is DTE Electric's fourth rate case in five years. In its past three rate cases, DTE Electric has secured rate increases that total approximately $500 million. If the Commission were to approve the company's requested

[529] DTE Electric's initial brief, p. 148.

rate increase in this case, DTE Electric's rate increases over the last five years would total roughly $750 million. Yet the $824 million revenue requirement associated the requested IRM would more than double that five-year rate increase over a period of just 32 months. Nothing in the Commission's limited approval of IRMs in the past justifies locking in the massive jump in rates sought by DTE here.

MEC/NRDC/SC contends that the IRM that DTE electric is seeking in here would be unprecedented in scope and amount. Further MEC argues that the company has failed to demonstrate that it needs an IRM or that its proposed IRM would cover reasonable and prudent expenditures. MEC/NRDC/SC points out that DTE Gas's MMO, PI and MRP are much less costly, very narrowly focused on safety and regulatory compliance, with limited flexibility in moving funds between programs.

The Attorney General recommends that the Commission deny the Company's request for such a large IRM, which would provide the company with unquestioned and unvetted funding to the detriment of customers. She argues that, as with previous cases, there are significant policy concerns if the Commission were to approve the proposed IRM. The concerns are detailed in the testimony of witness Mr. Coppola.

ABATE argues that DTE has proposed a new regulatory mechanism in order to capture the large capital investment needed to modernize its delivery system infrastructure and to invest in new generating resources. Further, arguing that on policy grounds the IRM is not reasonable and significantly erodes customer protections in setting rates.

ABATE witness Mr. Gorman provided several reasons that it should be rejected. First the company's proposal to use post-test year capital expenditures to justify additional charges on customers is imbalanced and will result in excessive charges to customers. Second, the company will allow for the inclusion of significant capital investments prior to a determination by the Commission that the investments are reasonable and prudent and the need for the investment is justified based on used and useful utility plant. Third, the proposed IRM will eliminate incentives for DTE to manage costs and to consider rate impacts on customers informing its capital investment decisions. Further, the IRM will provide an economic incentive to unnecessarily increase capital investments to improve earnings in cash flow rather than to manage capital spending while considering rate impacts on customers, while maintaining service quality and reliability.

Walmart argues that the proposed IRM shifts the risk of regulatory lag for the incremental capital expenditures to ratepayers rather than DTE Electric's shareholders, and Kroger maintains that the IRM is illegal single-issue ratemaking.

In its briefs, DTE Electric insists that the IRM is reasonable and prudent, contending that the various arguments opposing the IRM are "based on policy viewpoints opposing IRMs generally."[530] DTE Electric complains that these objections fail to recognize the prior proceedings approving and expanding the MMO, MRP, and PI programs, reiterating that that the electric IRM is quite similar to those previously-approved gas programs.

This PFD agrees with the arguments brought by Staff and the other parties. The company has failed to establish that the proposed IRM expenses are reasonable and prudent, or that there will be any real benefits to approving the proposal. The ALJ agrees that the IRM, as proposed by the company, is too expensive, too expansive, and allows

[530] DTE Electric's reply brief, p. 147.

the company far too much discretion in spending before any review of reasonableness and prudence occurs. DTE Electric's dismissal of the other parties' arguments as "based on policy viewpoints" with which the company disagrees, is not well taken. As MEC/NRDC/SC point out, in Case No. U-17735, the Commission agreed with the ALJ in that case that the IRM could be rejected on policy grounds alone.[531]

This PFD recommends that the Commission deny the company's proposed Infrastructure Recovery Mechanism.

C. <u>Nuclear Surcharge</u>

Mr. Davis testified that DTE Electric is proposing an increase to the nuclear surcharge, based on an updated calculation using the same method approved in the company's last three rate cases.[532] Mr. Davis explained that the portion of the surcharge that covers the cost of low-level radioactive waste (LLRW) disposal is projected to increase $2.0 million Mr. Bloch supported the calculation of the nuclear surcharge as shown in Exhibit A-16, Schedule F6.[533]

Mr. Andrews testified that the nuclear surcharge includes funding for the nuclear decommissioning trust, site security and radiation protection, and LLRW disposal. In the company's previous rate case, the Commission approved costs totaling $35.6 million,

[531] MEC/NRDC/SC's initial brief, p. 42.
[532] 5Tr 1293; Exhibit A-20, Schedule J1.
[533] 5 Tr 1227.

including $2.9 million for decommissioning, $4.0 million for LLRW disposal, and $28.7 million for site security.

Mr. Andrews took issue with DTE Electric's calculation with the amount that the company has included in the surcharge for decommissioning. Mr. Andrews noted that DTE Electric has based its amount for decommissioning on a study that was done in 2002.[534] Mr. Andrews explained that the nuclear decommissioning funds are held to recover the costs of nuclear decommissioning and license termination, no sooner than 2045, including the removal of non-radioactive structures, storage of nuclear waste, and returning the site to greenfield status. According to Mr. Andrews, the 2002 study itself was based on a 1996 study, performed by the Nuclear Regulatory Commission (NRC), based on a generic nuclear plant. Mr. Andrews testified that although the 2002 report is reviewed annually to ensure that it continues to meet accounting standards, the underlying cost, inflation, and return assumptions have not been critically evaluated to determine if the estimates for decommissioning, license termination, spent fuel storage, site remediation are reasonable.[535]

Mr. Andrews testified that DTE Electric assumes that decommissioning costs increase 6% a year, and returns on fund investments are 7% per year, for a 1% real rate of return. Mr. Andrews disputed the use of a 6% cost inflation rate, noting that the Energy Information Administration only projects average inflation of 2.6% (CPI) and 1.8% (producer price index) from 2017 through 2050. Mr. Andrews noted that some costs may increase at a higher rate than inflation, but it is incorrect to assume that all costs with

[534] 7 Tr 2856; Exhibit AB-5.
[535] 7 Tr 2857.

increase at 6% per year. Mr. Andrews also pointed out that DTE Electric only assumes 2.2% inflation for costs associated with decommissioning its coal plants.[536]

Mr. Andrews testified that the only support DTE Electric provided was the company's Triennial Fermi 2 Funding report which states that costs have increased 6.8% from 1986-2016. Mr. Andrews characterized this as misleading because the only costs at issue are license termination costs; and the 6.8% inflation figure does not apply to decommissioning or site remediation cost escalation.[537]

Mr. Andrews pointed to a publication by Callan that provides an annual assessment of nuclear decommissioning trust funds (Callan Report), based on publicly available information from 99 nuclear reactors in the United States. Mr. Andrews highlighted portions of the Callan Report including the average decommissioning cost estimate ($829 per kW), compared to DTE Electric's cost estimate of $1,676 per kW, and the average cost escalation rate of 3.02% compared to DTE Electric's assumed inflation of 6%.[538]

Mr. Andrews suggested that with minor adjustments, DTE Electric could cover the increased costs of nuclear waste disposal and site security using excess funds in the decommissioning trust fund.

In rebuttal, Mr. Davis testified:

> Witness Andrews mistakenly concludes that because DTE Electric does not use separate accounts to invest the Nuclear Decommissioning Trust monies for each category of decommissioning, then all the funds within the Nuclear Decommissioning Trust are available for interchangeable use. To the contrary of Witness Andrews' conclusions, the funds of the Nuclear Decommissioning Trust have specific allowable end uses and the

536 Id. at 2857-2858.
537 7 Tr 2858; Exhibit AB-7.
538 7 Tr 2859-2861; Exhibit AB-8.

allocation of funds within the Nuclear Decommissioning Trust is not arbitrary.[539]

This PFD finds that DTE Electric's nuclear surcharge should be approved as proposed, subject to a requirement that the company provide an updated decommissioning study in its next rate case, or in a stand-alone proceeding as has been done in the past.[540] DTE Electric corrected pointed out that the amounts in the nuclear trust fund cannot be reallocated without NRC approval. However, ABATE presented compelling evidence that that the assumptions underlying the calculation of the amount needed to decommission Fermi 2 may no longer be valid and should be revisited. DTE Electric did not dispute that the last decommissioning study was performed years ago, nor did it rebut Mr. Andrew's evidence about decommissioning amounts in trust funds for other nuclear plants that are roughly 50% of the amount DTE Electric has in its trust fund on a cost per kW basis.

D. Accounting Requests

1. Program Evaluation and Review Committee Expense

In Case No. U-18014, the Commission approved the company's suggestion, with the Staff's clarification, to include $4.9 million in program evaluation and review committee (PERC) nuclear O&M expense, with any spending above that amount to be deferred as a regulatory asset and amortized. In the event PERC spending was less than $4.9 million, the regulatory asset would be reduced by the underspent amount.[541]

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[539] 5 Tr 1311.
[540] *See, e.g.,* Case Nos. U-15276 and U-11662.
[541] January 31, 2017 order in Case No. U-18014, pp. 73-74.

Mr. Davis testified regarding PERC O&M expenditures for 2017 through the projected test year. Mr. Davis explained that for 2017, actual expenditures were $27 million, $31.5 million in 2018, $19.5 million in 2019, and $16.8 million in the test year.[542] Mr. Davis testified that the increase in PERC costs is largely driven by costs associated with the 24-month operating cycle project, which is expected to reduce refueling outages from every 18 months to every 24 months.[543]

Ms. Uzenski testified that, consistent with the Commission's order in Case No.U-18014, deferred PERC costs above $4.9 million are amortized over a five-year period beginning with the first month of a projected test period.[544] The April 2020 balance reflects $64.1 million of deferred expense less $18.4 million cumulative amortization.

Mr. Coppola recommended a disallowance of $2.9 million in PERC amortization expense for 2019. According to Mr. Coppola, there was no PERC amortization expense in 2017, but the company nevertheless projected amortization expense of $12.7 million for the test year. Because 2019 costs are unknown at this point, it is speculative to make assumptions about the extent to which PERC costs will exceed the $4.9 million included in base O&M expense.[545]

The PFD finds that the PERC amortization expense was supported and should be approved. As Mr. Davis testified, the 24-month outage project has been ongoing since 2017, and is expected to reduce the frequency of planned outages at Fermi 2. In addition,

[542] 5 Tr 1291; Exhibit A-13, Schedule C5.16, page 1.
[543] 5 Tr 1292-1293.
[544] 7 Tr 3328-3329; Exhibit A-13, Schedule C5.17.
[545] 5 Tr 1600-1601.

Mr. Davis presented a detailed list of PERC projects in Exhibit A-13, Schedule C5.16, page 1, none of which were contested.

2. Other Accounting Requests

DTE Electric's accounting requests for regulatory asset treatment for certain Customer 360 costs and ADMS costs should be approved. As discussed above, the Attorney General's proposed disallowance of ADMS capital expense was rejected, and his request that the Commission deny regulatory asset treatment for certain ADMS costs was presented without support.

VIII.

REVENUE DEFICIENCY SUMMARY

In accordance with the foregoing findings, DTE Electric's jurisdictional revenue deficiency for the test year is $261,904,000, inclusive of the elimination of the "Credit A" credit approved in Case No. U-20105. The revenue deficiency is computed as shown in Appendix A.

IX.

COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES

A. Transmission, Distribution, and Uncollectibles Cost Allocation

In allocating transmission costs, DTE Electric used 12CP 100-0-0,[546] the same method used by ITC, the owner of the transmission system serving DTE Electric. This method was most recently approved by the Commission in Case No. U-18255 and was not contested in this case.[547] For distribution cost allocation, Mr. Lacey testified that the company uses (1) demand; (2) customer; and (3) those based on special studies:

> Demand based allocators are used for poles, wires, conduit, substations, transformers and other equipment that comprise the distribution system. Customer based allocators are used for service drops and billing. Special studies were performed to develop the basis for allocating meters and uncollectible expense. The proposed allocation method selected for distribution allocates distribution by voltage level class. Specifically, distribution is broken into residential secondary, commercial secondary, primary, sub-transmission, transmission, and lighting (E-1 Street Lighting, D-9 Outdoor Protective Lighting (OPL), and E-2 Traffic Signals). This allocation method was approved by the Commission's April 18, 2018 order in Case U-18255.[548]

For uncollectibles expense cost allocation, Mr. Lacey explained that the company assigned costs to major customer class based on net write-offs.[549] DTE Electric's proposed distribution and uncollectibles cost allocation methods were also undisputed and should therefore be approved.

B. Production Cost Allocation

DTE Electric allocated production costs on the basis of 4CP 75-0-25, wherein 75% of costs are allocated on the basis of demand and 25% are allocated on the basis of total energy.

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[546] 12CP [Coincident Peak] average of twelve months and 4CP represents the average of the four summer months, June through September. 7 Tr 3216.
[547] Id.
[548] 7 Tr 3217.
[549] 7 Tr 3219.

Mr. Jester testified that, in his view, production costs have been disproportionately allocated to residential customers since production costs were reallocated after the Commission's order in Case No. U-17689. Mr. Jester observed, "the share of production plant costs allocated to residential customers has increased by about 6 percentage points, the share of production plant costs allocated to secondary commercial customers has increased by about 2 percentage points, and the share allocated to industrial and primary commercial customers has decreased by about 8 percentage points."[550] Mr. Jester noted that residential rates in Michigan, particularly DTE Electric's residential rates, are especially high compared to other states. Mr. Jester posited that the reason that residential rates are skewed is largely because "DTE allocates too much of its generation costs based on 18 contribution to system peak and too little of its costs to energy."[551] According to Mr. Jester's calculations:

> The allocation 20 of costs per kWh of energy is $0.0285, while the allocation of costs per MW of demand is $121.78 thousand.
>
> This allocation of $0.0285 costs per kWh to energy is less than the $0.02895 average locational marginal price for off-peak hours and less than the $0.03942 average locational marginal price for on-peak hours computed by Mr. Farrell in his workpapers, and less than the overall average locational marginal price of $0.02951 per kWh that I computed from Mr. Farrell's data.
>
> This allocation of $121.78 thousand per MW direct costs to capacity exceeds the Cost of New Entry (CONE) for installed capacity adjusted for planning reserve margins. CONE is the maximum cost of capacity in MISO's resource adequacy construct. Exhibit MEC-7 is MISO's annual CONE filing letter to FERC, showing that CONE for MISO local resource zone 7, in which DTE operates, is $94.900 thousand per MW zonal resource credit. MISO's most recent Loss of Load Expectations report shows an unforced planning reserve margin of 8.4% for local resource zone 7. Thus, the maximum

[550] 7 Tr 2187; Exhibit MEC-5.
[551] 6 Tr 2190; Exhibit MEC-6.

> cost of capacity pursuant to the MISO resource adequacy construct is $102.876 per MW zonal resource credit.[552]

Consistent with this analysis, Mr. Jester recommended that, "[a]t a minimum, the Commission should require that costs allocated to capacity be limited to CONE adjusted for planning reserve margin and the remainder of production costs allocated to energy."[553]

In rebuttal, Mr. Lacey pointed out that:

> MEC Witness Jester correctly states that since Case No. U-17689, the share of production plant costs allocated to residential customers has increased by 6 percentage points. However, he fails to note, as shown on MEC-5, that 90% of this change occurred in the first case after U-17689 (40.105%to 45.5872%). In the three cases after U-17767 (U-18014, U-18255 and U-20162) the percentage has remained relatively constant (45.3%, 45.0978%, and 46.1873%). MEC Witness Jester's main complaint seems to be with the use of the 4CP75-0-25 method for production allocation. The 4CP 75-0-25 method allocates production plant costs 75% on 4CP and 25% on energy. The 4CP75-0-25 method has been approved by the Commission in all recent cases (U-17689, U-17767, U-18014 and U-18255) and I used it in this case.[554]

Mr. Dauphinais also took issue with Mr. Jester's analysis, contending that tying production costs to LMP or MISO capacity cost is unreasonable and contrary to Michigan law, which requires cost of service-based rates. Mr. Dauphinais also pointed out that Mr. Jester's comparison of DTE Electric's rates to rates in other states is misleading because Michigan is the only state that requires COS-based rates and because his analysis looks at rates (i.e., total delivered energy costs) overall, which include costs that are not based on production cost only. Mr. Dauphinais also criticized several of Mr. Jester's workpapers used to develop his exhibits as not transparent and containing errors. Mr. Dauphinais

[552] 6 Tr 2190-2191.
[553] 6 Tr 2191-2192.
[554] 7 Tr 3234.

further observes that DTE Electric is constructing new generation in order to meet peak demand and not energy.[555]

In its brief, MEC/NRDC/SC relies on Mr. Jester's testimony, and points out that, while Mr. Lacey is correct that the greatest amount of cost allocation shift indeed occurred immediately after Case No. U-17689 was decided, but even the small change (from 45.0978% to 46.1873%) proposed in this case, "it is a huge dollar impact on residential customers based on the enormous size of this cost category."[556]

MEC/NRDC/SC further observes that DTE Electric did not respond to Mr. Jester's testimony that energy costs are priced at less than LMP, whereas capacity costs are more than CONE. MEC/NRDC/SC therefore recommends:

> Based on (a) the continued upward trajectory of production costs being allocated to residential customers; (b) the growing gap between DTE's residential and primary rates; and (c) the disparity between DTE's allocations and the market prices of capacity and energy, it has become clear that DTE's method of production cost allocation does not ensure that rates are equal to the cost of service. Therefore, the Commission should modify DTE's method so that the capacity (demand) component is set no higher than 100% of CONE. If the Commission prefers a more incremental approach, it could modify the method so that the energy component is set to DTE's average LMP (on- and off-peak) and allocate the remainder to capacity. If the Commission decides not to modify production cost allocation in this case despite the trends and analysis discussed above, then at a minimum, the Commission should direct DTE in its next rate case to include in its COSS an allocation of production costs based on the equivalent peaker method or an approximation, for comparison purposes.[557]

In reply, DTE Electric contends that the Commission has employed the 4CP 75-0-25 production cost allocator in the last three rate cases, and MEC/NRDC/SC present no valid reason to revisit the company's method.

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[555] 6 Tr 1783-1784
[556] MEC/NRDC/SC's initial brief, p. 141; Exhibit MEC 160.
[557] MEC/NRDC/SC's initial brief, p. 144.

The ALJ finds that MEC/NRDC/SC's recommendation to review the production cost allocation method in the company's next rate case has merit. Although MCL 460.11(1) requires the Commission to "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[.]" the statute also provides that "[t]he 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." Thus, DTE Electric's reliance on *res judicata* is unavailing, when the statute itself contemplates that modifications to the production cost allocation method may be required,

DTE Electric did not rebut Mr. Jester's evidence that showed that, except for New York, Michigan (and DTE Electric in particular) are outliers with respect to the comparison of costs between the residential and industrial rate classes.[558] Nor did the company address the analysis that showed that DTE Electric's energy costs are lower than LMP, to the benefit of industrial customers, while capacity costs are higher than CONE, to the detriment of residential customers. Although Mr. Dauphinais provides a detailed critique of Mr. Jester's analysis, as MEC/NRDC/SC point out in their reply brief, much of Mr. Dauphinais' assessment does not stand up to scrutiny.[559]

Thus, this PFD recommends that production cost allocation should be revisited in either the company's next rate case, or in a special purpose proceeding as was done in Case No. U-17689.

[558] 6 Tr 2188-2189.
[559] MEC/NRDC/SC's reply brief, pp. 67-72.

X.

RATE DESIGN AND TARIFF ISSUES

A. Capacity Cost Calculation

With respect to the establishment of a capacity charge, MCL 460.6w(3) provides:

> (a) For the applicable term of the capacity charge, include the capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party.
>
> (b) For the applicable term of the capacity charge, subtract all non-capacity-related electric generation costs, including, but not limited to, costs previously set for recovery through net stranded cost recovery and securitization and the projected revenues, net of projected fuel costs, from all of the following:
> (i) All energy market sales.
> (ii) Off-system energy sales.
> (iii) Ancillary services sales.
> (iv) Energy sales under unit-specific bilateral contracts.

To implement the above-quoted section, the Commission opened a contested case for each affected utility, including DTE Electric in Case No. U-18248. In that case, the Commission found that in determining the capacity cost:

> The Commission finds DTE Electric's proposed method, which begins with total embedded production related costs and subtracts the non-capacity-related costs of fuel expense, variable O&M expense, and non-capacity related purchased power expense, to be a reasonable method under Section 6w(3)(a).
>
> However, unlike the I&M case(which was not decided under Act 341), Section 6w(3)(b) goes on to list amounts that must be deducted from embedded costs, including (net of projected fuel costs) all energy market sales, off-system energy sales, ancillary services sales, and unit-specific bilateral contract sales. DTE Electric offered deductions of $49 million on an annual net net (net of projected fuel costs, and net of total purchases or total losses) basis under Section 6w(3)(b). However, the statute says

> nothing about making this determination on an annual net net basis. The statute says "subtract all non-capacity-related electric generation costs . . . net of projected fuel costs, from all of the following: (i) All energy market sales. (ii) Off-system energy sales. (iii) Ancillary services sales." MCL 460.6w(3)(b). The plain language of the statute provides no support for DTE Electric's proposed interpretation.[560]

Accordingly, the Commission approved an SRM capacity charge of $97,527 per megawatt-year, ($267.20 per megawatt-day) for DTE Electric's full service customers.[561] The Commission reaffirmed this method for calculating the charge in the company's subsequent rate case.[562]

In this case, through the testimony of Mr. Arnold, Mr. Lacey, and Mr. Stanczak, DTE Electric again used a "net net" method for calculating the capacity charge. In its initial brief, DTE Electric reaffirmed its contention that the correct calculation for the capacity charge should be based on net energy sales net of fuel, rather than gross energy sales net of fuel. DTE Electric added that in Case No. U-18255, the company did not oppose the Commission's approach, to use the same sales adjustment used in Case No. U-18248, under the circumstances, "but reserved all rights in further proceedings."[563]

DTE Electric's proposal was opposed by the Staff, ABATE, Energy Michigan, and Kroger, largely on grounds that the Commission has twice determined that "<u>all</u> energy market sales" means just that, and it does not mean, as DTE Electric would have it, "excess generation sold into the MISO market after serving the company's bundled load."[564] As Energy Michigan describes the record on this issue:

> Neither in its Direct nor Rebuttal Testimony did DTE explain <u>why</u> it deviated from the precedent established in the previous Commission

[560] November 21, 2017 order in Case No. U-18248, pp. 65-66 (internal citations omitted).
[561] Id. p. 79, ¶ B.
[562] April 18, 2018 order in Case No. U-18255, pp. 61-63.
[563] DTE Electric's initial brief, p. 115.
[564] 3 Tr 290.

orders in U-18248 and U-18255 for calculating "all energy market sales." However, as Mr. Zakem explains, DTE's testimony does explain where the methodology derives from. DTE witness Mr. Arnold explains that the methodology by which he derived the numbers for energy market sales, among other items, was adopted "at the direction of Company Witness Stanczak." Mr. Arnold's testimony, as Mr. Zakem notes, omits "all" from "energy market sales" and defines those sales as "excess generation," which is in direct conflict with previous Commission orders. However, as noted, he places the responsibility for choosing that method on Mr. Stanczak. Then, in the Direct Testimony of DTE witness Mr. Thomas M. Lacey, Mr. Lacey is asked about the difference in the calculation of energy sales in this case from that adopted in U-18255 (and therefore in U-18248). His response is, "I used the calculation of energy sales net of fuel supported by Company Witness Mr. Arnold on his Exhibit A-29, Schedule S3. The Commission reflected a $584 million reduction for energy sales net of fuel in case U-18255, based on a calculation originally adopted in Case No. U-18248."[565]

In a related issue, Mr. Arnold testified that that there are additional MISO costs associated with energy sales that should be netted against revenue:

> MISO incurs costs when providing the following services including, but not limited to: 1) market modeling and scheduling functions; 2) market bidding support; 3) locational marginal pricing support; 4) market settlements and billing; 5) market monitoring functions; and, 6) simultaneous co-optimization for the scheduling and enabling of the least-cost, security-constrained commitment and dispatch of Generation Resources to serve Load and provide Operating Reserves in the MISO Balancing Authority Areas while also establishing a spot energy market. MISO recovers these Energy and Operating Reserve Markets Support Administrative Service Cost through a recovery adder filed as Schedule 17 in the MISO tariff. The projected schedule 17 rate for 2018 is $0.073/MWh, so the Schedule 17 admin fees associated with the 2,389 GWh of projected energy market sales in 2018 is $0.2 million as shown on Exhibit A-29, Schedule S3, line 30.[566]

The Staff opposed inclusion of these costs. Mr. Gottschalk testified:

> The Company also inappropriately subtracted MISO Schedule 17 administrative costs from the projected energy sales revenue. There is absolutely no basis for this in the statute or in any previous cases deciding

[565] Energy Michigan's initial brief, pp. 3-4 (internal citations omitted).
[566] 3 Tr 293.

> this issue, and the Company failed to support their inclusion, and therefore, their inclusion should be rejected.[567]

DTE Electric did not provide rebuttal testimony on this issue. In its reply brief the company asserts:

> [A]s explained by Company Witnesses Arnold (3T 288-293) and Stanczak, (3T 70-73),the Company's calculation of $40.3 million of energy sales net of fuel is consistent with PA 341 Section 6w (3)(B) and results in Electric Choice customers paying the same full embedded cost of DTE's electric generation fleet as bundled customers. Thus, the Company's position should be adopted.[568]

This PFD finds that the Staff, ABATE, Energy Michigan, and Kroger have correctly analyzed the issues related to the calculation of the capacity charge. As these parties observed in their respective testimony and briefing, the Commission has made a determination, consistent with the plain language of the statute, that the offset to capacity costs under Section 6w is all energy sales net of fuel costs, and not the net net method that DTE Electric insists is correct. This PFD also agrees with the Staff that MISO Schedule 17 administrative costs are not included in MCL 460.6w(3)(b) and are therefore not appropriately included here. Accordingly, the capacity calculation and charges shown in Exhibit S-6, Schedule F1.4 should be adopted.

Finally, Mr. Bieber recommended that the SRM capacity charge be updated as part of this case using costs and revenues determined in the Commission's final order. In a related recommendation, DTE Electric proposed that the Commission review the capacity charge by December 1, 2018 and implement the new charge on January 1, 2019. In its initial brief, the Staff objected to these recommendations, arguing:

[567] 8 Tr 4272.
[568] DTE Electric's reply brief, p. 159.

> Staff contends that [updating the capacity charge in this proceeding] would not be possible unless an updated calculation was provided on the record with current costs using the same models used in the method that was approved by the Commission in cases U-18248 and U-18255. Absent this evidence, the Commission should continue to use the gross energy sales net of fuel amount it approved in these cases. The Commission should also require the Company to file updated amounts as described above using the most recent available numbers with its application in the Company's next general electric rate case.[569]

The Staff added that:

> [T]he Commission reviewed and updated the capacity charge in its April 27, 2018 Order in Case No. U-18255, which became effective for full service customers on May 1, 2018 and on June 1, 2018 for choice customers. Therefore, the Commission has already completed the required annual review for 2018 by December 1 and does not need to issue another capacity charge before the final order in U-20162, which will produce a capacity charge incorporating updated costs from this case.[570]

Although Kroger contends it has performed the required calculations to arrive at an updated capacity cost, its inputs were not particularly well examined by the parties. Thus, the PFD recommends that the Staff's approach to recalculating and updating the capacity charge is reasonable and should be adopted.

B. Customer Charges

1. Residential and Commercial Secondary Customer Charges

Mr. Lacey recommended that non-variable demand costs for residential and commercial secondary customers through its customer charge, noting that the company currently does not impose a demand charge on these customers. The application of Mr. Lacey's approach resulted in fixed charges of $45.53 for residential customers[571] and

[569] Staff's initial brief, pp. 126-127.
[570] Staff's initial brief, p. 128, quoting 8 Tr 4272-4273.
[571] Customers on rate schedules D1, D1.2, D1.6, D1.8, and D2.

$178.88 for commercial secondary customers.[572, 573] However, Mr. Dennis testified that "as a reasonable approach that steps towards recognizing that distribution demand related costs should not be recovered 100% through an energy based charge[,]" the residential customer charge should be increased from $7.50 to $9.00 per month. Ms. Holmes similarly testified that the Commercial Secondary charge should be increased from $11.25 to $15.00 per month.[574]

The Staff, MEC/NRDC/SC, the Attorney General, Soulardarity, and the RCG objected to the company's proposal for numerous reasons including that the company's method assumes that all distribution costs are fixed, when they are not, and that an increase in fixed customer charges would reduce economic efficiency; it could reduce investment in energy efficiency, and it would have a disparate impact on low income customers.

Mr. Gottschalk explained that in developing the residential and commercial secondary customer charges, the Staff included "expenses incurred from customer installs, meters, customer accounts (excluding uncollectible accounts), customer service and information (excluding sales expenses), depreciation and amortization expense corresponding to meters and services in rate base, return on meters and services in rate base less accumulated depreciation, and finally, property tax on meters and services in rate base."[575] Once these costs are determined and summed, the cost is divided by the number of customers. Mr. Gottschalk testified that "Staff's cost-of-service based method produces a residential customer charge of $7.19 and a commercial secondary customer

[572] Customers on rate schedules D1.8, D3, D3.2, D3.3 D4, and R8 separately metered.
[573] 7 Tr 3221; Exhibit A-16, Schedule F1.4.
[574] 5 Tr 1430-1431.
[575] 8 Tr 4267; Exhibit S-6, Schedule F1.3.

charge of $9.68 per month."[576] Because these costs are reasonably close to the current charges of $7.50 and $11.25 per month for residential and commercial secondary customers (respectively) the Staff recommended that charges remain the same.[577]

This PFD finds that the Staff's recommendation, to retain the current charges for residential and commercial secondary customers, should be adopted. In DTE Electric's last three electric rate cases, the company has advocated for inclusion of at least some demand-related costs, along with customer-related costs, as part of the monthly customer service charge for residential and commercial secondary customers. The Commission has consistently rejected the company's approach and adopted the method proposed by the Staff. Despite the Commission's decisions on this issue, the most recent of which occurred less than one year ago, Mr. Lacey again proposed the inclusion of demand-related costs as part of the customer charge. In this regard, DTE Electric should be mindful of its own admonition that parties should not be "forced to respond repeatedly to arguments that have been conclusively resolved, as if the Commission's prior decisions are meaningless[.]"[578]

2. Primary Voltage Customer Charge

Mr. Bieber testified that DTE Electric did not perform any analysis to determine whether its primary voltage customer charge is cost based, and although the Commission has found the charge to be reasonable, in the company's previous rate case, "it did *not* determine the primary monthly service charge was *cost-based*."[579] Mr. Bieber referenced

[576] 8 Tr 4269.
[577] Id.
[578] DTE Electric's reply brief, p. X.
[579] 7 Tr 2712-2713.

prior Commission orders, in Case No. U-17767 and U-18014, noting that in these orders as well, the Commission did not find that the charge was cost-based, only that it was reasonable.[580]

Mr. Bieber recommended that DTE Electric be directed to design its monthly service charge for primary customers consistent with the Commission's determinations regarding the costs that should be included in the customer charge, i.e., only the marginal cost of customers connecting to the system. Alternatively, Mr. Bieber suggested that the Commission could order DTE Electric to use its cost analysis from Case No. U-18255, which calculated a customer charge of $53.52 per month for primary customers.[581] Mr. Bieber added that "utilizing the primary monthly customer charge of $53.52, I determined that the primary distribution demand charge should be $4.17 per kW of demand, in order to collect the remaining primary distribution revenue requirement. This would be an increase of $0.29 relative to DTE's proposed primary distribution demand rate."[582] Mr. Bieber concluded that his calculations were based on the company's revenue requirement presented in this filing and to the extent that the final rates are above or below the requested rates, "then each rate element and charge should be reduced [or increased] by that same percentage."[583]

In rebuttal, Mr. Lacey contends that the Commission has never agreed that the customer charge for primary voltage customers should be calculated in the same way as the Staff's method for calculating residential and commercial secondary charges, and the Commission has consistently found the charge to be reasonable.

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[580] Id. at 2715-2716.
[581] 7 Tr 2718; Exhibit KRO-4.
[582] 7 Tr 2718-2719; KRO-5.
[583] 7 Tr 2719.

The parties' briefs follow the testimony of their respective witnesses.

This PFD finds that Kroger's position has merit, and that the customer charge for primary customers in this case should be calculated using the same method that the Commission has consistently approved for residential and commercial secondary customers. Mr. Bieber's proposal to use the cost-of-service based calculation from Case No. U-18255 is also reasonable and should be adopted. Alternatively, the Commission should direct DTE Electric, in its next rate case, to calculate the customer charge for primary customers consistent with the method used for residential and commercial secondary customers discussed above.

C. Fixed Bill and Weekend Flex Pilot Proposals

Mr. Clinton described the company's proposed Fixed Bill pilot as "[an] offering that allows up to 5,000 residential customers to elect and pay a fixed monthly amount for a period of one year that is not subject to any adjustments for actual usage."[584] According to Mr. Clinton, DTE Electric surveyed 700 residential customers to gauge interest in such a program and found that 28% found the offer appealing and 11% would choose the fixed-bill option over their current rate.[585] Mr. Clinton noted that interest was especially keen among customers who already participate in the company's BudgetWise Billing program. Mr. Clinton explained that the Fixed Bill pilot will be available to customers in Rate D1, who have been in their residence for at least one year and who are in good financial

[584] 6 Tr 2097.
[585] Id.

standing with the company.[586] If approved, the company plans to implement the program beginning January 1, 2020.[587]

Mr. Clinton testified that the company will calculate the fixed bill amount for the next 12 months on the basis of the previous 12 months of weather-normalized usage for that customer "and any expected changes in usage . . . The resulting sum will be increased by a risk adder not to exceed 10% to appropriately price the risk associated with weather variability and commodity price fluctuations."[588] Mr. Clinton added that customers will receive updated fixed bill amounts for the next year after 11 months of participation and will be automatically renewed in the program unless the customer notifies the company. Customers who leave the program early (i.e., before or after one year of participation) may be charged a fee calculated as the difference between what the customer would have paid under Rate D1 and the fixed bill amount, if the Rate D1 amount is greater.[589]

Mr. Clinton testified that the company may terminate a customer's participation in the program if the customer's usage in a given month is 30% greater than the amount used in the same month the previous year on a temperature-normalized basis. The customer would be transferred to a standard tariff, with the same early-termination provision that applies to early withdrawal from the program.[590]

Mr. Clinton stated that because the fixed bill amount is calculated based on the previous 12 months of usage, "customers are, over the long term, incentivized to use less

[586] 6 Tr 2098; Exhibit A-16, Schedule F10.
[587] 6 Tr 2101.
[588] 6 Tr 2097.
[589] 6 Tr 2098-2099.
[590] 6 Tr 2099.

as this may decrease their monthly renewal price for the next 12-month term."[591] Mr. Clinton added that customers will receive a "welcome package" that includes energy savings tips and information on the company's energy efficiency programs. And, "Customers will continue to see current month actual usage charted and compared to the same month last year in order to proactively inform the customer of the potential for an increased Fixed Bill renewal offer."[592] These efforts, coupled with the potential for termination from the program in the event a customer's usage is excessive, will help align the Fixed Bill program with the company's energy efficiency efforts.[593]

Mr. Clinton testified that other customers would not subsidize Fixed Bill customers in the event that these customers have higher than estimated usage:

> DTE has not and would not impute a loss associated with the Fixed Bill program. Under a full program, DTE would impute either zero or some level of positive revenue which would offset the residential rate class revenue requirement thereby improving affordability.[594]

Mr. Clinton added that the first priority revenue stream from the Fixed Bill program will be assigned to the PSCR and other surcharges and these surcharges will be fully funded based on the customer's actual usage compared to the estimated usage. Finally, Mr. Clinton cited three utilities that are currently implementing fixed bill programs, the billing rules waivers the company was requesting,[595] and listed the cost and performance metrics the company intends to monitor over the life of the pilot.[596]

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[591] 6 Tr 2100.
[592] Id.
[593] 6 Tr 2101-2102.
[594] 6 Tr 2100.
[595] Namely, Mich Admin Code R 460.121 and R 460.125.
[596] 6 Tr 2102, 2103-2104

For the Weekend Flex pilot, Mr. Clinton again indicated that the pilot would be limited to 5000 customers and that participating customers would pay the standard D1 rate for weekday usage and a fixed rate for weekend (e.g., 12 a.m. Saturday through 11:59 p.m. Sunday) usage. To determine the fixed weekend charge, customers would be grouped according to the previous year's annual usage from 2000 kWh per year to 16,000 kWh per year, in 2000 kWh tranches.

> The pricing in each 2,000 kWh tranche is based upon the average annual usage for all residential D1 customers within that tranche. A forecasted load shift, detailed by Witness Farrell, would be embedded into each usage tranche to determine the estimated annual weekend consumption. The estimated annual weekend consumption would then be priced out using the D1 rate (including all applicable surcharges) and divided by 12 to obtain a monthly fixed charge. Each tranche would have an associated weekend fixed monthly charge that applies to all customers within the tranche, exclusive of the monthly service charge and other per customer or per meter surcharges.[597]

Mr. Ferrell calculated an anticipated load shift of 5% for customers participating in the Weekend Flex program based on data comparing Rate D1 customer usage to usage by customers participating in the company's time-of-use tariff (Rate D1.2):

> Using the same on and off-peak schedule as D1.2 (the on-peak period being weekdays from 11:00 a.m. to 7:00 p.m.), the average D1 customer uses 25% of their energy on peak compared to 22% for D1.2 customers. For an average D1 customer to reduce their on-peak usage from 25% to 22%, the average D1 customer would have to shift 13% of their on-peak load to the off-peak period. Relative to the Weekend Flex Pilot, annually there are less off-peak hours than there are relative to D1.2. The weekend flex has 2,520 hours that can be defined as "off-peak" compared to 6,680 hours that are defined as "off-peak" in rate schedule D1.2. This equates to the weekend flex having 38% of the available "off peak" hours compared to D1.2. To adjust for the fewer hours in the Weekend Flex Pilot Program, I multiplied the anticipated13% shift from on-peak to off-peak (or from weekday to weekend) by 38% (the amount of available "off-peak" hours

[597] 6 Tr 2088; Exhibit A-16, Schedule F8.

> compared to D1.2) to calculate an average 5% forecasted shift for customers participating in the Weekend Flex Pilot Program[.][598]

Mr. Clinton testified that DTE Electric was interested in piloting the Weekend Flex program to provide an additional option to its customers, increase customer satisfaction, and shift peak usage from weekdays to off-peak weekend periods. Again, DTE Electric surveyed customers and found 29% were interested in the Weekend Flex program and 6% would sign up if the program were offered.[599] Mr. Clinton noted that "potential subscribers would come disproportionately from standard rate customers in households earning less than $100,000 per year."[600]

Mr. Clinton explained the eligibility criteria for the Weekend Flex pilot, which again requires that applicants be in good financial standing with the company and currently on rate D1, prescribes minimum and maximum annual consumption amounts, requires that a 12-month usage history be available, and an AMI meter installed at the premises. Again, customers would have to make a 12-month commitment to the pilot, and the program would be cost-based and revenue neutral.[601] Customers would also be subject to a reasonable usage clause, and a participant could be eliminated from the program if weekend usage exceeds 30% of the estimated usage. Mr. Clinton testified that, like the Fixed Bill program, "the Weekend Flex pilot sends a long-term conservation signal because the offer covers a 12-month period and subsequent offers will incorporate usage changes."[602]

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[598] 5 Tr 1344-1345
[599] 6 Tr 2089-2090.
[600] 6 Tr 2090.
[601] 6 Trr 2091-2092.
[602] 6 Tr 2093.

Through Mr. Revere's testimony, the Staff recommended that the Commission disapprove both the Fixed Bill and Weekend Flex pilots. According to Mr. Revere, "Both pilots dilute (or practically eliminate) the price signals sent to customers to facilitate economically efficient use of electricity. In addition, the disconnect between usage and what customers pay would likely hamper Energy Waste Reduction efforts."[603] Mr. Revere opined that the level of interest and expectation of increased satisfaction in utility service expressed by survey participants "does not outweigh concerns related to diluting price signals for these customers."[604]

In response to the company's claim that the possibility of a higher fixed charge in the following year would lead to conservation over the long term, Mr. Revere testified that neither the Fixed Bill nor Weekend Flex programs actually promote conservation because the lack of a clear price signal will lead to inefficient usage. Mr. Revere added that the Staff had other concerns with the program:

> Staff does not support the "reasonable usage clause" proposed by the Company, as it would result in exactly the behavior Staff is concerned about due to the dilution of price signals, which would then require the customer to pay what they would have paid had the correct price signals been sent in the first place. If the Commission should decide to approve this program, the reasonable usage clause should not be approved, or result in customers being removed from the program without being required to pay what they would have paid under normal rates. Staff also does not support the automatic re-enrollment of customers into either pilot. Customers should be required to proactively request to remain on either pilot when the renewal is necessary.[605]

Mr. Coppola testified that while he lauds the company's efforts to increase customer convenience and satisfaction, Mr. Clinton cited no other benefits to the Fixed

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[603] 8 Tr 4298.
[604] Id. at 4299.
[605] Id.

Bill program beyond survey participants' interest due to the prospect of equal monthly bills. At the same time, Mr. Coppola observed that the company included $1 million in start-up O&M costs for the program, which might increase if additional changes to the company's billing system are required. In addition, Mr. Coppola also raised concerns that the program would dampen energy conservation efforts among participants, which would "be at odds with other programs promoted by the Company to increase energy conservation, energy efficiency and reduction of peak time usage. The fact that the Company will adjust the fixed bill up or down the following year may not deter customers from reducing energy conservation during critical peak times of the year." Mr. Coppola also observed that DTE Electric already offers a budget-billing option, thus the Fixed Bill program appears duplicative.[606]

Mr. Coppola testified that, with respect to the Weekend Flex pilot, the company proposes to spend $0.4 million during the projected test period, noting that "the actual cost is much higher. In his estimate, Mr. Clinton did not include $1.2 million of additional IT capital expenditure which the Company would seek to recover in a future rate case proceeding."[607] Mr. Coppola opined that although the objective of the Weekend Flex program has merit, it would be less costly to incentivize customers to shift usage to off-peak times by implementing a lower weekend rate as part of the company's existing TOU programs.[608] Therefore, he recommended that the Commission deny the $400,000 O&M expense for the Weekend Flex pilot.

[606] 6 Tr 1608-1609.
[607] 6 Tr 1610.
[608] Id.

On behalf of MEC/NRCD/SC, Mr. Jester testified that the Weekend Flex pilot should be approved, characterizing the program as "a potentially interesting experiment in shifting customer load to weekends and reducing the Company's peak loads and therefore the Company's costs."[609] However, Mr. Jester's view of the Fixed Bill proposal was consistent with that of Mr. Revere and Mr. Coppola. Mr. Jester testified that the Fixed Bill program "does not have a clear advantage over an equal monthly billing scheme with an annual true-up," such a program could encourage increased energy usage, and "the Company's proposal to evaluate effects on usage are strictly short-term and therefore might be expected to reflect usage behavior rather than product purchase decisions where energy efficiency might be considered."[610]

In rebuttal, Mr. Clinton maintained that Mr. Revere's claim, that the proposed programs would dilute price signals, was not based on any data or case study and was therefore speculative. Mr. Clinton added that the usage alerts and reasonable usage requirement of the program would help mitigate any dilution of price signals.[611] Mr. Clinton also disagreed with Mr. Revere's recommendation that program participants be required to opt in to another year of participation, noting that "there is long precedent for all residential customers, by default, remaining on their current electric pricing or billing options until they indicate their desire for change to DTE Electric."[612]

Mr. Clinton disagreed with Mr. Revere's recommendation that customers whose usage is excessive should be removed from the program without any financial penalty. According to Mr. Clinton:

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[609] 6 Tr 2198.
[610] 6 Tr 2198-2199.
[611] 6 Tr 2112.
[612] 6 Tr 2113.

> Under the reasonable usage clause proposal outlined by Staff, the potential for the behavior Staff is concerned with is likely exacerbated as customers would have no financial consequences for their actions of increasing usage. In essence, Staff is concerned about diluting price signals but has proposed an alternative that, in fact, dilutes price signals and eliminates the financial consequence of increased usage.[613]

Mr. Clinton took issue with Mr. Revere's contention that the percentage of customers surveyed who indicated an interest in enrolling in the Fixed Bill or Weekend Flex programs was insufficient to outweigh concerns about the dilution of price signals to those customers. Mr. Clinton pointed out that 11% of the customers surveyed indicated they would enroll in the Fixed Bill program, a percentage which, if extrapolated to DTE Electric's entire residential customer base, would result in enrollment of 218,000 customers. Similarly, the 6% of surveyed customers who stated they would enroll in the Weekend Flex program equates to 100,000 customers, extrapolated across the company's entire customer base.[614]

Mr. Clinton disagreed with Mr. Coppola's suggestion that it would be less costly to change TOU rates so that weekend usage is charged at a significantly lower rate. Mr. Clinton agreed that current TOU programs incentivize customers to shift usage to weekends, however, "[t]he Weekend Flex pilot is unique in that it is a time-of-use electric pricing option with a fixed component for usage. This fixed component of the provision is a key element that may resonate with certain customers that may have otherwise passed on DTE Electric's current variable rate structured time-of-use options."[615]

The parties' briefs and reply briefs generally rely on the testimony of their respective witnesses. DTE Electric emphasizes customer interest in these programs,

[613] 6 Tr 2115.
[614] 6 Tr 2116-2117.
[615] 6 Tr 2118.

noting that it is proceeding cautiously. DTE Electric adds that none of the parties opposing the programs provided any studies to support their positions.

The Staff contends that although the company's surveys purport show some interest in signing up for these programs, "Staff is concerned acquiescence bias may have played a significant part in the results[,]" suggesting that, "[f]or future surveys used to justify novel pricing, Staff recommends the Commission require the Company to avoid acquiescence bias through proper survey design and prove that they have done so as part of filings and supporting documents."[616]The Attorney General and MEC/NRDC/SC also oppose the pilot programs.

This PFD finds that the proposed Fixed Bill pilot program should be rejected on grounds that, more likely than not, the effects of the program would be contrary to the energy conservation policy goals of the State Michigan and the company's energy efficiency efforts. Indeed, the Commission raised this same concern when DTE Electric (then The Detroit Edison Company) proposed a similar program in 2012:

> The Commission finds that the request to provide a waiver of the Billing Rules to facilitate the Fixed-Bill Pilot Program that Detroit Edison proposes should not be granted on an *ex parte* basis on grounds that such a program may not be in the public interest, or it may violate the public policy of the State of Michigan. While there is some suggestion that a levelized billing program would be an attractive option for certain customers, the Commission is nevertheless concerned that participants in the proposed program will be inclined to use more energy (and more energy on-peak) than they would have used under more traditional billing options, as has been seen in other states where similar fixed-bill programs have been implemented. (*See*, *e.g.*, North Carolina Utility Commission Dockets E-2, Sub 847 and E-7, Sub 710; 263 PUR 4th 362, NCUC (2008)).[617] Thus,

[616] Staff's initial brief, p. 152.
[617] Specifically, in the order cited above, the North Carolina Utility Commission found in its evaluation of these programs for Duke Energy Carolinas, LLC (Duke) and Progress Energy Carolinas (PEC):

> With respect to the impact of these programs on energy conservation, Duke's filing shows that FPP customers increase energy usage on average by 9.3% in the first year, 2.9% in the second

> approval of this program could run afoul of the legislative mandate requiring the Commission to encourage energy efficiency and demand side management. *See*, Section 91 of 2008 PA 295, MCL 460.1091 *et seq*.[618]

The concerns about the effects on energy efficiency efforts remain, and they are particularly salient considering the expanded energy savings requirements under Act 342, not to mention the company's efforts to reduce on-peak usage through various DR programs. In addition, Mr. Jester and Mr. Coppola raise a valid point, namely that the Fixed Bill program does not appear to provide much more benefit to customers than the company's BudgetWise Billing program, which could perhaps be improved by implementing the same type of usage alerts, as proposed for the Fixed Bill program, that would warn customers about potentially higher budget bill amounts in the future.

A recommendation on the Weekend Flex program is a closer call. While noting the initial support of MEC/NRDC/SC for this pilot, this PFD nevertheless finds that the proposal should be rejected on grounds that it is largely duplicative of the company's current TOU rate programs, which, as the Attorney General points out, could be modified to provide a larger discount for weekend usage. In addition, the design of the Weekend Flex program is exceptionally complex and could result in significant customer confusion.

> year, and 1.3% in the third year as compared to predicted energy usage. PEC's filing shows that BBP customers increase energy usage by 6.94% in the first year, 2.99% in the second year, and 1.68% in the third year as compared to the predicted level of energy usage. Thus, based on the studies of Duke and PEC, the average FPP or BBP customer increases energy usage approximately 7% to 9% in the first year of participation. However, the increases in usage decline in the second and third years of participation. The average increase in usage in the third year of participation is approximately 1% to 2% over the predicted level of usage.
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> * * *
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> Concerning the impact of these programs on peak demand, Duke reported that load research data gathered for a statistical sample of FPP customers and compared to a control group showed that FPP customers had 31% higher usage at peak than the control group in 2004. Duke also reported, however, that this trend has declined year by year and that, in 2006, the FPP sample showed 11% higher usage.

[618] December 20, 2012 order in Case No. U-17054, p. 3. Subsequent to that order establishing a contested case, the company withdrew its application. *See*, January 31, 2013 order in Case No. U-17054.

Finally, should the Commission decide to approve either of these pilots, this PFD agrees with the Staff that, although removing participants from the program for excessive usage is appropriate, charging a penalty is not. As Mr. Revere pointed out, customers would be essentially penalized for failing to respond to a price signal that the company did not supply in the first place.

D. Rate D8 and D11

Mr. Bloch testified that Rate D11 is DTE Electric's principal primary rate schedule serving customers at primary, sub-transmission, and transmission voltage levels. Rate D8 is DTE Electric's primary voltage interruptible rate.[619] Mr. Bloch explained that rather than using the method approved in Case No. U-18255 for calculating billing demand voltage level adjustments:

> The energy voltage level discounts for Rates D11 and D8 were treated as one class for determining energy voltage level discounts since both rates share the same energy rates. Voltage level loss adjustments were applied to the D11and D8 voltage level sales to determine loss adjusted sales. Loss adjusted sales were used to allocate energy revenue to each voltage level and then voltage level energy rates were calculated to determine the voltage level energy discounts. . . . The Billing Demand voltage level adjustments were determined separately for D6.2, D8 and D11 to account for differences in each rates voltage level contribution to the 4CP. This is appropriate since the power supply expenses collected through the billing demand charges are allocated to the D6.2, D8 and D11 classes on their respective 4CP. Demand revenue was allocated based on the voltage level 4CP and then divided by the voltage level billing demands to determine voltage level demand rates and voltage level adjustments which account for both loss factors and cost allocation differences at each voltage. For D8, the 4CP contributions were adjusted to remove product protection demands. Product protection demands were removed since product protection receives the D11 billing demand charge and associated demand charge voltage adjustments.[620]

[619] 5 Tr 1221.
[620] 5 Tr 1224; Exhibit A-16, Schedule F-12.

Mr. Bloch further explained:

> Transmission related voltage level demand adjustments were determined separately for D8 and D11 to account for differences in each rate's voltage level contribution to the 12CP. Transmission costs were allocated to each voltage level following the same cost of service principles used to determine billing demand voltage level adjustments which considers both loss factors and cost allocation differences. For transmission expenses, the appropriate cost allocator is each voltage levels' 12CP as this is the same allocation basis used to allocate transmission expenses in COS. Transmission demand revenue requirement was allocated based on the voltage level 12CP and then divided by the voltage level billing demands to determine voltage level demand rates and voltage level adjustments which account for both loss factors and cost allocation differences at each voltage.[621]

Mr. Bloch testified that the method approved for determining billing demand for voltage level adjustments in Case No. U-18255 should be replaced with his method because his proposed method is cost-of-service based and avoids intra-class subsidies. According to Mr. Bloch, "The approved method [from U-18255] only considers loss differences between voltage levels but fails to consider the voltage level cost responsibility to which the losses are applied[,]" adding, [t]he Commission's direction to determine voltage differentiated power supply demand charges must be interpreted to mean voltage level demand charges that are consistent with cost based principles."[622]

Mr. Gottschalk testified that, like DTE Electric, the Staff designed primary class distribution rates, "by calculating one distribution rate for each voltage level to be applied uniformly to every primary class rate schedule, with the exception of rates D10, R1.1, and R1.2, which have energy-based delivery charges. For these rates, Staff calculated

[621] 5 Tr 1224-1225.
[622] Id. at 1225.

energy charges equivalent to Staff's voltage level distribution charges."[623] However, for the power supply demand charge and energy voltage level discounts, Mr. Gottschalk testified that it appeared that DTE Electric used the same method the company proposed in its previous rate case, "where loss adjusted sales are used to allocate energy revenue to each voltage level and then voltage level energy rates are used to determine the proposed voltage level energy discounts." Conversely, the Staff used the same method approved in Case No. U-18255, where "[t]he voltage level loss factor differentials for demand and energy are applied directly to the proposed demand and energy charges to produce the discounts."[624]

Mr. Andrews testified that for Rate D11, there are three voltage level discounts: one for energy, one for capacity demand, and one for non-capacity demand. Mr. Andrews testified that DTE Electric calculated the energy discount consistent with ABATE's previous recommendations; however, for the capacity and non-capacity demand discounts, the company employed a different method that Mr. Andrews characterized as "significantly flawed," pointing to the incorrect differential between discounts for transmission and sub-transmission customers.[625] Mr. Andrews therefore recommended that the method approved in Case No. U-18255 continue to be used.

In rebuttal, Mr. Bloch testified that DTE Electric's proposed method addresses intra-class subsidies:

> Under the current method, voltage level loss factors are applied to the average billing demand charge for the class. However, the costs that make up the average billing demand charge vary by voltage level. To determine demand voltage level discounts without accounting for voltage level cost differences, which are known values and significantly

[623] 8 Tr 4285.
[624] 8 Tr 4286.
[625] 7 Tr 2848-2851.

> affect the outcome, does not follow cost of service principles. For example, of the costs allocated to the D11 rate class that are included in the billing demand charge, transmission voltage level customers have a higher relative cost responsibility than subtransmission and primary voltage customers due to their higher relative 4CPdemand. Voltage level cost differences are equally relevant to setting voltage level demand discounts as are loss factors and can have a more significant impact than loss factors on demand voltage level discounts. To not recognize the voltage level cost differences based on the 4CP demand would be in stark contrast to how the Company allocates all of its other power supply related capacity costs. The current method does not account for voltage level cost difference and results in shifting rates further from cost of service and increasing intra-class subsidies which runs contrary to the principles of setting cost based rates..[626]

In its brief, DTE Electric relies on Mr. Bloch's testimony, reiterating that its method for determining demand discounts is cost-based and that the method approved in Case No. U-18255 is not. In its brief, the Staff reviewed Commission orders in Case Nos. U-17767, U-18014, and U-18255, and argues that the company has not provided sufficient new evidence in this case to merit a change to the method approved in Case No. U-18255. Similarly, ABATE asserts that the voltage level discounts for both energy and demand should be based on the Commission's previously-approved method.

This PFD agrees with the Staff and ABATE that DTE Electric's method for calculating voltage level demand discounts should be rejected. As the Staff and ABATE point out, the Commission determined in Case No U-18255:

> ABATE provided convincing evidence that the differences in line losses (1.03 MW at the transmission level versus 1.09 MW at the primary level, to deliver 1.0 MW of demand) provide a rational basis for the discount. The Commission agrees with the Staff and ABATE that it is reasonable to adopt the same methodology for calculating both the demand and energy voltage level discounts, and that voltage level line loss differences provide an appropriate basis. Like the ALJ, the Commission finds that the Staff's proposal is consistent with the method approved in the

[626] 5 Tr 1257-1258.

> 2017 order [in Case No. U18014] for determination of the rates themselves.[627]

DTE Electric has not shown that its method is cost-based; in fact ABATE's evidence, that under the company's method the discounts for sub-transmission level are greater than those for transmission level, appears to demonstrate the opposite. Accordingly, this PFD recommends that the Commission again approve the Staff's method for calculating demand and energy voltage level discounts.

E. Rider 3 Stand-by Service

1. Allocation of Power Supply Cost to Rider 3

Mr. Bloch explained that Rider 3 (R3) provides standby service for customers that have self-generating facilities. In this case, Mr. Bloch testified that the company is proposing to change the method for allocating power supply capacity costs to R3 customers, as well as the basis for changing the generation reservation fee approved in Case No. U-18255. Mr. Bloch explained that consistent with the Commission's decision in Case No. U-18014, DTE Electric filed a separate COSS for R3, despite the company's concerns about the small size of the class, the irregular loads, and varying sizes of the generators. Mr. Bloch stated that while the Commission decided not to treat R3 customers as a separate class, it nevertheless agreed with ABATE's power supply revenue requirement based on 4CP data averaged over 10 years.[628]

Since that method was implemented, Mr. Bloch testified:

> The Company has determined that R3's 4CP does not accurately represent standby service loads placed on the system during peak load periods, due to its demand variability, and does not provide an appropriate basis to determine power supply cost allocation to the R3 Class. Therefore, the

[627] April 18, 2018 order, Case No. U-18255, p. 69.
[628] 5 Tr 1233,

> method of averaging R3 4CPs over several years, as recommended by ABATE, does not correctly address this variability, it only masks it, resulting in D11 customers subsidizing R3 customers.[629]

In support of this claim, Mr. Bloch presented three tables containing data from 2017 showing that 54% of the time R3 customers exceeded 4CP during the summer peak hours, compared to 20% or less for other customer classes (Table 1); the variance of the average hourly load above 4CP in the summer months is 108% for R3 compared to less than 10% for other customer classes (Table 2); and the class variance for R3 (180%) during the maximum peak hour in 2017. Based on this analysis, Mr. Bloch concluded:

> The Class 4CP to actual Class load comparisons presented in Tables 1-3 and discussed above, clearly demonstrate that due to the demand variability of the R3 class, 4CP is not representative of the demands R3 places on the system during high demand periods and should not be used to allocate costs to R3. Further, averaging 4CPs over several years does not address this variability, it only masks it, resulting in D11 customers subsidizing R3 customers.[630]

Mr. Bloch recommended:

> [C]alculating an equivalent 4CP demand for the R3 class by taking their actual 4NCP demand shown in Table 2 and reducing it by a variance adjustment in line with normal system load classes, which all operate with variances below 10%. Using 10%results in an equivalent 4CP demand of approximately 16MW. Allocating capacity costs on this basis results in a capacity revenue requirement for R3 of $3.895 million.

Mr. Krause disagreed that 4CP demand was an inappropriate allocator for R3, explaining that any smaller group of customers (i.e., R3 customers within D11) will tend to show more variance than the entire class of customers. "This is the nature of diversity, the larger the group of customers, the smoother the total load shape is going to be and the less variance you will see." Mr. Krause added that "It is possible that 4CP

[629] Id.
[630] 5 Tr 1235-1236.

is a poor allocator for D11 in general, and that the strength of 4CP as an allocator lies in other rate schedules so that 4CP makes a reasonable allocator when all rate schedules are considered in total."[631] Mr. Krause recommended that the 4CP method approved for R3 cost allocation in the company's previous rate case should continue to be used.

Mr. Dauphinais pointed out that in the company's last rate case, the Commission determined that power supply cost allocation to R3 customers should be based on actual 10-year normalized 4CP values. Mr. Dauphinais testified that to his knowledge, no other Commission has approved the cost allocation method DTE Electric proposes here. Mr. Dauphinais added that DTE Electric's method is inconsistent with the MISO resource adequacy requirements for capacity, it includes hours during which MISO system demand is below annual peak system demand, and it is not supported by historical actual information on 4CP R3 demand.[632] Consistent with his testimony, Mr. Dauphinais recommended that DTE Electric again be required to allocate power supply costs consistent with the method approved in Case No. U-18255.

Ms. Scripps testified regarding the value of CHP systems in Michigan along with increased customer interest in investing in these systems, noting "CHP adoption across Michigan offers a low-cost approach to new electricity generation and uses highly skilled Michigan labor and technology to develop, implement, and operate projects."[633] Ms. Scripps explained that several states have issued policy statements and have undertaken proceedings on stand-by rate design in recognition that "[h]igh standby rates can be a barrier to the deployment of otherwise economic CHP."[634]

[631] 8 Tr 4243.
[632] 6 Tr 1742.
[633] 8 Tr 3465; Exhibit EIB-2.
[634] Id. at 3266.

With respect to DTE Electric's proposal to change the power supply cost allocation, Ms. Scripps testified:

> [T]he proposed move from 4CP to NCP for Rider 3 customers is concerning because it moves away from cost causation principles and arbitrarily allocates power supply costs. Unlike NCP or non-coincident peak load, which looks to a customer class' maximum load irrespective of when it occurs, 4CP is an appropriate basis for cost allocation because it reflects customers' actual contribution to system peaks, which drive Company investments in common, shared facilities.[635]

In rebuttal, Mr. Bloch contended that the Commission should support an allocation method that better reflects cost-causation, as his method does. Mr. Bloch also characterized much of the testimony by Mr. Dauphais and Ms. Scripps as unsupported or incorrect.[636]

The parties' briefs and reply briefs rely on the testimony of their respective witnesses.

As discussed more below, this PFD finds persuasive the recommendation by the Staff, ABATE, and EIBC/IEI, that the power supply cost allocation method approved in Case No. U-18255 should be retained.

2. Generation Reservation Fee

While acknowledging the Commission's decision in the company's previous rate case, Mr. Bloch nevertheless contended that "[t]he order in U-18255 did not specifically address the concerns presented by the Company that availability is not the appropriate basis to set generation reservation fee since availability does not reflect generator performance and the Company's need to reserve capacity."[637] Mr. Bloch explained

[635] 8 Tr 3475.
[636] 5 Tr 1251.
[637] 5 Tr 1237-1238.

that to demonstrate that the use of generator availability is not the appropriate method to use to set the reservation fee:

> [U]sing 2017 data, I compared three of the largest R3 standby customers which all have annual availabilities of 98% or higher to determine if their use of standby service was in the 2% range, as the above premise would suggest. The results indicate an average annual standby requirement of 30%, which ranged from 17% to over 50%.

Mr. Bloch also discussed the consequences of the Commission's decision on the reservation charge in Case No. U-18255:

> In addition to these concerns, from a rate design perspective, the Commission's order in U-18255, approving ABATE's proposed R3 changes, has over constrained the R3 rate design by having all R3 demand charges based [sic] the D11 billing demand (maintenance demand is 50% of daily demand, daily demand is 10% of the D11 billing demand, and generation reservation fee is set based on forced outage rate applied to the D11 Billing Demand). This constraint limits the ability to design R3 capacity rates equal to R3 costs, which are not determined based on the D11 billing demand. Prior to the R3 changes adopted in U-18255, any changes in R3 power supply revenue requirement were designed into R3 by changing each demand rate on an equal percentage basis to maintain existing recovery relationships.[638]

Mr. Bloch therefore recommended that the Commission "remove the requirement to set the generation reservation fee based on availability and allow changes in R3 capacity revenue requirement to be collected through the generation reservation fee."[639]

Mr. Dauphinais points out that Mr. Bloch's recommendation and argument in this case was rejected in the company's previous rate case. Mr. Dauphinais testified that the reservation charge is not related to the actual use of stand-by service, "[i]t is simply a minimum required contribution toward fixed power supply costs that must be paid

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[638] 5 Tr 1239.
[639] Id.

regardless of how much stand-by service power is taken by the customer."[640]

Ms. Scripps similarly pointed out that "Rider 3 has several mechanisms to charge customers for actual use of standby service during an outage, but the generation reservation fee should be geared toward the likelihood of unexpected use, which is captured by a CHP system's forced outage rate."[641]

In rebuttal, Mr. Bloch testified:

> [T]he forced outage rate of the best performing customers is not an appropriate indicator of the level of capacity required to standby for a customer's generator load. Forced outage rate is a measure of the availability of a generator to operate and does not reflect the level of generation produced by a generator. … In addition, to use forced outage rate as the sole basis for setting the generation reservation fee fails to consider how the customer will operate their generator. This is especially true when considering customer owned CHP projects which are designed and operated to serve both thermal and electric loads. For many CHP projects, the primary operating objective is to serve a customer's thermal (heating, cooling and process) load requirements, with electric generation as a secondary consideration.[642]

Again, the parties rely on the testimony of their respective witnesses to support the arguments in their briefs.

In the April 18, 2018 order in Case No. U-18255, p. 77, the Commission determined that:

> [I]t is reasonable to approve an R3 standby tariff that sets a monthly power supply reservation charge based on the forced outage rates of the best performing generators, an on-peak daily power supply demand charge based on a proration of the full service D11 monthly power supply demand charge, and a maintenance on-peak demand charge of 50% of the on-peak daily power supply demand charge. The Commission went on to find "that the R3 on-peak daily demand charge should be set at 1/10th of the D11 demand charge.

[640] 6 Tr 1752-1753.
[641] 8 Tr 3477.
[642] 5 Tr 1252.

As this PFD found above with respect to power supply cost allocation, the method for determining the reservation charge should be retained. As the Staff points out, setting the stand-by rates for R3 in this manner is consistent with the Staff's Standby Rates Workgroup Report, and, at this point, DTE Electric has limited experience with the changes included in R3 in the previous rate case.

F. Rate D1 Summer On-peak Non-Capacity Charges

In its reply brief, DTE Electric explained:

> [T]he Commission previously directed the Company to include a proposal to redesign its residential rates in its next rate case (this case) (April 18, 2018 Order in Case No. U-18255, pp 81-82, and p 86, Ordering paragraph E). DTE Electric moved for rehearing, pointing out that even if the directive were clarified for accuracy, it still would have unintended consequences because approximately 1.9 million customers would be defaulted to time-based rates for non-capacity charges, with significant impacts on the Company's rate structure and individual customers' bills. The Commission granted the request for clarification, re-affirmed the substance of its decision, and left implementation issues open to further consideration (June 28, 2018 Order on Rehearing, p 7).[643]

In the instant case, DTE Electric again requests that the Commission reverse its decision, on the same grounds it raised in its petition for rehearing in Case No. U-18255. The Staff notes that the company's arguments in this case are the same as those previously presented and rejected.

In the event that the Commission denies the request to reverse its decision on summer TOU rates applied to the non-capacity portion of the bill, DTE Electric requests that: (1) all costs, including educational costs, for the transition be approved; (2) the Staff's recommendation to explore shadow billing be rejected; (3) the company's

[643] DTE Electric's reply brief, pp. 163-164 (fn omitted).

proposed rate structure be approved; and (4) the Commission approve the company's "Recommended Plan" for implementation rather than its "Alternative Plan." These issues are addressed below.

1. Implementation Costs

Mr. Griffin testified that IT implementation costs for the TOU rate would require 22 months at a cost of approximately $24 million. Ms. Johnson explained that customer service costs were expected to be $12 million in the first year of implementation and decrease to $4 million annually thereafter. Mr. Clinton stated that education and marketing costs are estimated at $9.3 million.

The Staff did not oppose the company's proposal to defer and amortize up to $45 million in expenses for transition to summer on-peak TOU rates. However, the Staff expressed some reservation about including certain education costs associated with altering usage. According to the Staff, the purpose of the summer on-peak rate applied to non-capacity costs is to better align with COS, and not to drive behavioral changes with respect to energy usage.

In its initial brief, the Staff appears to agree with the company that customers will need to be educated about the new rate, but insist that education about usage changes should not be included in the regulatory asset.[644] Mr. Jester proposes that implementation costs should be offset by savings. However, as DTE Electric points out, the savings accrue to customers, not the company, and are therefore not available to offset the company's costs.

[644] In its initial brief, p. 33, the Staff appears to narrow its opposition to the inclusion of "costs for the Company to design a large-scale demand response program." As DTE Electric points out, there is nothing in the record that indicates that the company has any plans to design or implement such a plan.

This PFD agrees with the parties that costs, up to $45 million, for transitioning to summer on-peak rates should be deferred and amortized. While the Staff raises concerns that certain education costs should not be included in the regulatory asset, it does not appear that these costs are significant (compared to the overall costs of the transition) or that the company intends to go beyond educating customers about the new summer rate. In addition, because the company already has TOU rates designed to incentivize usage changes, the ALJ assumes that educational materials and programs are already developed for those rates. This PFD finds that the company's proposal to defer and amortize up to $45 million in transition expenses should be approved.

2. Shadow Billing

Mr. Matthews explained that shadow billing:

> is a billing practice that calculates a customer's bill using their actual, historic billing determinants as if the customer were on a different rate, such as a time-of-use rate. For easy comparison the results of the shadow bill (hypothetical bill on a different rate) may be printed on the customer's actual monthly bill, included in an online billing tool, or through the Company's popular DTE Insight application. Staff recommends that the Company explore shadow billing capabilities for inclusion in its next rate case.[645]

DTE Electric contends that it would be impractical for the company to implement shadow billing given the difficulty and need for precision in the calculations. DTE Electric also questions whether backward-looking shadow billing is helpful, noting that customers may be dissatisfied if they see that their bills would be lower under the previous rate structure.[646]

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[645] 8 Tr 4146.
[646] 6 Tr 2129.

In its initial brief, the Staff maintains that shadow billing provides customers with more information than simply comparing theoretical rates:

> It is easier for a customer to see how their actual usage on a rate would affect their bill than to see how their bill would theoretically change under a new rate. For this reason, it is important for the Company to use actual billing determinants when doing any kind of rate calculator. Staff believes strongly that shadow billing is the correct tool that will invigorate customer commitment to different rate programs offered by the utility such as time-of-use structured rates.[647]

The Staff further points out that the Commission recently addressed the same issue in the March 29, 2018 order in Case No. U-18322, pp. 77-78, where the Commission continued to support shadow billing and a trial period where customers could explore new rates.

The PFD agrees with the Staff that, in the company's next rate case, DTE Electric should be directed to present a plan for implementing shadow billing for customers wishing to explore different rates. As the Staff points out, the use of actual data, as opposed to theoretical comparisons is more likely to increase customer interest in alternative programs.

3. Rate Structure for Time of Use

The Staff states that it agrees with the company's on-peak time period as 4:00p.m. until 9:00 p.m. Monday through Friday from June 1 through September 30. The Staff, however, disagreed with the company's differential between on- and off-peak hours. Mr. Revere testified:

> Staff opposes the Company's proposals for two reasons. First, for the residential rate differential, the Company utilized the summer on/off-peak differential. In Staff's opinion, the differential should be based on the Locational Marginal Price (LMP) differential between summer on-peak (as

[647] Staff's initial brief, p. 169.

defined by the Company, 4PM-9PM) and all other kWh, as those are the time periods the rate utilizes. Using data provided by the Company, Staff calculated the differential on Exhibit S-16.2. Staff recommends this differential be utilized for residential rate design, incorporating further adjustments described below. Second, the Company uses the difference in LMPs in cents per kWh to guide their rate differentials. In Staff's opinion, it is more appropriate to utilize the percentage difference in LMPs to guide the rate differentials. For example, as the LMP (combined with capacity, as described below) for all hours other than summer on-peak is approximately 2.9 cents per kWh, and the LMP for summer on-peak is approximately 4.1 cents per kWh, the differential is approximately 1.3 cents, or 44%. When applied to the rates actually charged to residential customers, however, that same differential is only approximately 37% ((3.7-2.7)/3.7). While the difference between the two percentages does not seem like much, Staff's proposed non-capacity charges are higher than the Company's, exacerbating the issue and further driving the results apart. Therefore, Staff recommends the percentage LMP differences be utilized to guide differentials. In addition, the Company maintained the current rate structure for capacity charges. This is inappropriate. It is more appropriate to apply the same on- and off-peak definitions to the capacity charge as the non-capacity charge, rather than maintaining the inappropriate and unnecessary current structure. In Staff's opinion, it is appropriate to charge more for capacity during summer on-peak hours, as this is when the peaks that determine allocation are set. Therefore, Staff proposes to apply the same differential to capacity rates as to non-capacity rates. This is consistent with Staff's proposal in the current Consumers Energy electric general rate case, MPSC Case No. U-20134. [648]

Alternatively, Mr. Revere proposed:

Staff recommends that the capacity rate be the same for the Summer on-peak and off-peak periods. The current rate structure should not be maintained. Staff's recommendation is reflected on pages 3 and 7 of Exhibit S-6, Schedule F3.[649]

Mr. Jester recommended that the summer on-peak and off-peak rates should be applied to capacity and non-capacity charges on grounds that only applying the rate to non-capacity charges results in intra-class subsidies.

In response, DTE Electric points out that the Staff's primary recommendation:

[648] 8 Tr 4301-4302.
[649] Id. at 4302.

> is inconsistent with the April 18, 2018 Order in Case No. U-18255 . . . which "retain[ed] the current rate design for capacity charges" and directed the Company "in its next general rate case filing, to include proposed tariffs for *non-capacity charges* based on summer on-peak rates." Therefore, the Company's proposal to only convert the Rate Schedule D1 non-capacity charges to a summer on-peak structure is consistent with the Commission's Order.[650]

However, with respect to the Staff's alternative recommendation, DTE Electric states:

> The Company could agree with this alternative, that the capacity rate should be set to a flat per kWh charge, as opposed to the existing inverted block rate. This change, which would take place at the same time as the new D1 rate structure becomes effective, would help simplify the rate for easier understanding for both customers and DTE's internal Customer Service and Marketing staff . . .
>
> The Company agrees with the Staff's recommendation that the D1 capacity rate (non-time based) be set to a flat per kWh charge, as opposed to the existing inverted block rate (8T 3883). The Company is agreeable to the same structural changes to Rate Schedule D1.6, the Special Low Income Pilot Rate, which has historically mirrored D1's rate structure (8T 3866). Customers who opt out of AMI should be subject to the same rate options as other residential customers, since consumption information is available via manual meter reads.[651]

With respect to MEC/NRDC/SC's proposal to implement TOU for both capacity and non-capacity charges, DTE Electric points out this proposal was rejected in the company's last rate case and need not be revisited here.

Concerning the company's proposed price differential for on-and off-peak rates, DTE Electric maintains:

> Mr. Dennis explained that the Company's proposed methodology provides a more accurate portrayal of the difference in LMP price – Staff's methodology increases the differential beyond the actual LMP differential. The increased differential calculated on a percentage basis, compared to the actual price differential is further exacerbated by Staff applying this percentage differential not only to Staff's proposed noncapacity rates, but also to its proposed capacity rates (which is contrary to the April 18, 2018

[650] DTE Electric's reply brief, p. 170.
[651] Id. at 171.

> Order in Case No. U-18255, as discussed above). This results in Staff proposing a total on peak / off peak differential of approximately 3.7 cents, even though the actual LMP price differential per Staff, according to its own Exhibit S-16.2, is only 1.257 cents per kWh. Staff's proposed methodology thus results in a differential beyond the actual price differential, and therefore should not be adopted.[652]

DTE Electric further argues that "[i]mplementing a larger differential than the Company proposes could have a negative impact on customer acceptance and satisfaction, and would significantly increase revenue recovery risk (*i.e.*, the larger the differential, the higher the revenue impact if customers change usage behavior differently than expected)." DTE Electric observed that the Staff's proposed price differential is almost four times what the company proposed.

This PFD finds that with respect to rate design for summer on-peak/off-peak non-capacity charges, DTE Electric's proposals, including the Staff's alternative proposal to which the company has agreed, should be adopted. As DTE Electric points out, the Staff's and MEC/NRDC/SC's recommendations do not comport with the Commission's order in U-18255. In addition, the ALJ agrees that the larger price differential between on-peak and off-peak non-capacity charges proposed by the Staff could lead to customer dissatisfaction and larger usage shifts and revenue impacts than expected. Nevertheless, the Staff's proposal should be explored further in the company's next rate case.

4. <u>Implementation Plan</u>

DTE Electric explained in its initial brief that it has a recommended and alternative plan:

> The Recommended Plan allows for piloting multiple rates to allow for a more comprehensive assessment of potential rate designs. This will help

[652] Id. at 172.

determine a rate design(s) that is best for the Company's customers over the long-term. Given the significant costs and extended timing issues related to implementing a new rate structure, it is appropriate to assess and anticipate what other changes may be appropriate for the Company to best serve customers and offer additional options beyond the proposed summer on-peak rate. The Recommended Plan also allows for testing multiple messages among different customer groups and researching effective marketing and education (3T 101). Mr. Stanczak testified that it is important to get each customer on the right rate and provide for potential opt-in rate alternatives. The Company must analyze and understand the impacts to customers for whom a summer on-peak rate is not feasible or appropriate. For example, customers who cannot shift load without significant adverse impacts, customers who should not shift load due to unique health reasons, and customers who should be aware of other rate options. Therefore, it is necessary to pilot multiple rates and evaluate results to determine customer implications from a summer on-peak rate compared to other opt-in rate alternatives. It would also be unfortunate to not utilize this rate transition period as an opportunity for a comprehensive assessment of rate design that benefits customers in the long term.[653]

DTE Electric continues, explaining the alternative plan:

The Alternative Plan allows for the piloting of only a single rate in phase one, unlike the Recommended Plan which allows for piloting multiple rates. Piloting only a single rate results in a projected go-live date of June 2021 compared to May 2022 for the Recommended Plan. The Alternative Plan provides less time to gather information and study customer behavior due to summer on-peak rate changes, and to develop solutions to potential issues identified during the pilot phase (3T 101-102). The Company believes that it should obtain insight into customer interests during this transition to time of use rates. The Recommended Plan allows the Company time to work with its customers to introduce the Commission required time of use rates with the focus on minimizing any potential negative impact to our customers.[654]

In response to DTE Electric's two implementation proposals, the Staff points out:

The main difference between the two plans is a later implementation date in the recommended plan to allow for testing different rate designs. (8 TR 4301.) Staff recommends that the alternative plan be approved, as the Company's proposed rate design is appropriate, and there is therefore no need to test alternative designs. Id. The Company attempts to justify the recommended plan by lumping in other potential rate design examinations unrelated to the summer on-peak transition. (3 TR 102-103.) These other rate design examinations are unrelated to the summer on-peak transition,

[653] DTE Electric's initial brief, pp. 125-126.
[654] Id. p. 126.

> can take place any time, and should therefore not be used to justify putting of the transition more than is required to prepare the underlying technical support.[655]

The ALJ finds the Staff's position persuasive. There does not appear to be a need to pilot a number of different rate design alternative, especially given the finding above that the company's more modest rate design proposal was reasonable and should be adopted. In addition, the ALJ agrees with the Staff that many of the company's proposals are related to other residential programs such as TOU and critical peak pricing that can be piloted at any time.

G. Distributed Generation Tariff (Rider 18)

1. Background and Legal Requirements

Prior to the enactment of Acts 341 and 342 in 2016, 2008 PA 295 (Act 295) provided for both "true" net metering[656] and "modified" net metering compensation mechanisms for small, customer-owned generation projects. However, under these more recent enactments, except for projects that are "grandfathered" under MCL 460.6a(14) and MCL 460.1183(1), new projects are subject to compensation under a distributed generation tariff. Section 173(1) of Act 342, MCL 460.1173(1) provides:

> The commission shall establish a distributed generation program by order issued not later than 90 days after the effective date of the 2016 act that amended this section.[657] The commission may promulgate rules the commission considers necessary to implement this program. Any rules adopted regarding time limits for approval of parallel operation shall recognize reliability and safety complications including those arising from equipment saturation, use of multiple technologies, and proximity to synchronous motor loads. The program shall apply to all electric utilities

[655] Staff's initial brief, p. 155.
[656] "True" net metering applies to systems 20kW and under. A "true" net metering customer receives full retail rate for any excess generation that flows out to the utility's system.
[657] Acts 341 and 342 were effective April 20, 2017.

whose rates are regulated by the commission and alternative electric suppliers in this state.

MCL 460.6a(14) provides:

Within 1 year after the effective date of the amendatory act that added this subsection, the commission shall conduct a study on an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. In any rate case filed after June 1, 2018, the commission shall approve such a tariff for inclusion in the rates of all customers participating in a net metering or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. A tariff established under this subsection does not apply to customers participating in a net metering program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211, before the date that the commission establishes a tariff under this subsection, who continues to participate in the program at their current site or facility.

In response to the directive to establish a DG program within 90 days, after notice and an opportunity to comment, the Commission issued an order on July 12, 2017, finding, "until such time as new distributed generation tariffs are approved after June 1, 2018, keeping the net metering (now, distributed generation) program in place, as it is currently structured, is the most reasonable approach."[658]

To address the requirements under Section 6a(14) concerning the completion of a study of an appropriate distributed generation tariff, the Staff convened a distributed generation workgroup in March 2017, which met several times throughout the remainder of the year. Participants in the workgroup included utility industry representatives, environmental organizations, and business and technical organizations. The workgroup process culminated in a final report and proposed DG tariff filed on February 21, 2018.

[658] July 12, 2017 order in Case No. U-18383, p. 5.

In an order issued on February 22, 2018, the Commission approved the "Inflow-Outflow" method embodied in the proposed DG tariff, stating:

> [T]he Commission agrees that the Staff's proposed Inflow/Outflow method for developing a DG tariff is cost-of-service based and that it otherwise comports with the requirements of Act 341. Nevertheless, electric providers and other interested parties will still have an opportunity to propose alternative DG tariffs, along with an Inflow/Outflow approach, in electric rate cases filed after June 1, 2018. In the interim, the Commission agrees with the Staff's recommendation that a contested case be opened to address appropriate inputs to calculate the outflow credit.[659]

In that same order, the Commission requested another round of comments on several topics relevant to this discussion, including the following:

> (1) Are there any concerns with the recommended process for developing and approving a DG tariff as discussed above (i.e., an interim case to develop a uniform outflow compensation method, coupled with a rate case to finalize the DG tariff)?
>
> (2) The DG Study relied primarily on the language in MCL 460.6a(14) to develop a method and tariff "reflecting equitable cost of service for utility revenue requirements" for DG customers. This method would replace net metering and modified net metering for customers who enroll after the tariff is approved. Are there any legal limitations to the implementation of the Inflow/Outflow method and tariff as proposed in the DG Report? Specifically, does adoption of the Inflow/Outflow billing method conflict with Sections 177(4) and (5) of 2008 PA 295, MCL 460.1177(5)?

And,

[659] February 22, 2018 order in Case No. U18383. The Staff's DG report recommended that Public Utilities Regulatory Policies Act (PURPA) avoided costs be used to determine the outflow credit in the interim and that a separate proceeding be established to determine a uniform outflow credit. Report, pp. 3-4. The Commission modified its decision to hold a separate proceeding to determine the appropriate outflow credit in an order issued in this docket on April 18, 2018, p. 15, where if found that:

> [T]he most efficient procedure is to approve a new tariff in each utility's post-June 1, 2018 rate case, which will allow the Commission to consider the unique circumstance of each utility and other applicable factors to determine the final DG tariff to include in each utility's rates. Therefore, in any rate case filed after June 1, 2018, the utility shall file the Inflow/Outflow tariff, as discussed *supra*. However, because the Commission is reserving final determination of a DG tariff for a post-June 1, 2018 rate case, the utility may also file its own alternative DG tariff. The Commission recognizes the novelty and difficulty in developing a new DG tariff and finds that permitting the rate-regulated utilities to also file an alternative DG tariff will enable the most thorough evaluation possible.

(4) In the July 12 order, the Commission found that the current net metering program should continue as the DG program until new DG tariffs are approved in rate cases filed after June 1, 2018. In addition, under MCL 460.1183 and MCL 460.6a(14), any customer "participating" in a net metering or DG program before the new DG tariff is approved may continue net metering for 10 years, or may opt to receive service under a DG tariff. At what point should a customer be considered to be "participating" in a net metering program?[660]

The Commission addressed the comments on the above matters in an order issued on April 18, 2018 in Case No. U-18383. The Commission made the following findings with respect to the process for developing the tariff:

(1) The Commission has clear authority under MCL 460.6a(14) to develop a DG tariff that reflects COS, where "tariff" is equivalent to a "billing mechanism" or structure and not a "rate" or specific numerical value.

(2) The Commission has authority to require rate regulated utilities to file an Inflow/Outflow tariff so that the Commission can review its applicability to the specific circumstances of each utility.

(3) The Commission conducted a reasonable COS analysis given the limited information available on DG customers at the time the study was conducted. In the future, as more cost and benefit information becomes available, the Inflow/Outflow inputs and tariff can be updated.

(4) Although the Staff recommended a contested proceeding to determine a uniform outflow credit, the lack of such a proceeding does not render the DG study incomplete.

(5) There is insufficient diversity between and among DG and non-DG customers to merit separating the small number of DG customers into a separate class for COSS purposes.

Concerning the purported conflict between the proposed Inflow/Outflow method and MCL 460.1177(4) and (5), the Commission explained:

> In their comments, DTE Electric and Consumers averred that the Staff's Inflow/Outflow billing mechanism conflicts with Section 177(4) and (5). The utilities argue that subsection (4) prescribes the compensation for all excess generation, whether defined on a total outflow basis or on a net excess basis (outflow minus inflow), and that such compensation is limited to one

[660] February 22, 2018 order in Case No. U-18383, pp. 5-6.

of two options, LMP or the power supply component of the full retail rate. The Commission disagrees with this interpretation.

The correct interpretation of Section 177, which reflects the definition of modified-net-metering billing method under MCL 460.1007(i), is that it establishes a netting system that divides excess generation into two baskets. Power outflows up to the level of inflow during the current billing period (or pricing period) are offset on a net energy basis, which is identical to true net metering. Because netting occurs on an energy basis, there is no need to designate a compensation rate for this portion of excess generation, and the statute reflects this fact by leaving the compensation rate undefined. It is, however, effectively equal to the full retail rate (power supply and distribution charges) during each relevant pricing period.

On the other hand, the remaining portion of excess generation (power outflow exceeding inflow) is monetized using the prescribed credit formulas set by subsection (4), the LMP or the power supply component of the retail rate, excluding transmission charges. Pursuant to Section 177, this compensation is not used in the current billing period, but is carried forward to the following billing period as a dollar credit or kilowatt hour (kWh) credit against power supply charges.

The second issue raised by DTE Electric and Consumers relates to the limitation of accumulated credits against future bills. In comments, DTE Electric and Consumers made the argument that any DG credit cannot be used to reduce distribution or transmission charges. This is an incorrect interpretation of Section 177(4). The relevant subsection (4) provision states, "[n]otwithstanding any law or regulation, distributed generation customers shall not receive credits for electric utility transmission or distribution charges." This exclusion refers to the formula for calculating compensation, which is expressed in the dual credit pricing options (LMP or power supply component excluding transmission charges), that immediately follows the prohibition. Under any reasonable interpretation, the transmission and distribution exclusion cannot refer to the level of accrued credits that can be applied to the customer bill for the following billing period since subsection (4) expressly allows the offset of the total power supply charges (which include transmission charges). Clearly, the transmission and distribution exclusion only applies to the modified net metering formula for calculating credits for the portion of outflow that exceeds inflow.

Further, if the credit limitation applied across the board, i.e., to total outflow, then both true net metering and modified net metering would be prohibited by subsection (4) since both billing methods credit power inflows at the full retail rate (which includes transmission and distribution charges). The utilities' interpretation of Section 177(4) sets the statute in conflict with itself and is thus erroneous.

> Third, DTE Electric and Consumers argue that subsection (5) restricts the Commission from approving outflow credits from offsetting any distribution charges applied to inflow since those charges are intended to recover the COS pursuant to Act 341. Again, this prohibition is explicitly directed toward credits for the portion of outflow that exceeds inflow under the modified net metering billing method.
>
> Section 177 applies only to modified net metering that continues to exist under the grandfathering provision in Act 342, Section 183 or under the new DG program (with an added charge to recover the COS). Section 177 does not apply to any DG billing method, such as the Inflow/Outflow billing mechanism, that implements a COS based tariff under Act 341, Section 6a(14). Instead, under Inflow/Outflow, a rate (full retail) is assigned to the energy supplied to the customer (the inflow), and a rate is assigned to the energy supplied to the grid by the customer (the outflow).[661]

Finally, with respect to the interim DG program, the Commission agreed with the Staff that a customer will be considered "participating" in the net metering program if the customer has a completed application pending before the utility before the effective date of a DG tariff approved in a rate case filed after June 1, 2018. The Commission also adopted DTE Electric's recommendation that a DG applicant must have his or her system completed within 6 months of the date that an application is deemed complete.[662] The Commission concluded:

> Section 6a(14) of Act 341 directs the Commission to "conduct a study on an appropriate tariff reflecting equitable cost of service" and "approve such a tariff" in a rate case filed after June 1, 2018. Within the timeframe permitted by the statute, the Staff has conducted an extensive study and analysis, which resulted in the development of the Inflow/Outflow tariff. The Inflow/Outflow tariff is an adaptable billing mechanism that allows for equitable COS and is enabled by improved data collection. As the DG program evolves and more data becomes available, the Commission will better be able to assess the cost and benefit impacts and conduct rate design consistent with COS principles. While the Commission finds that the Inflow/Outflow tariff resulting from the study satisfies the requirements of Section 6a(14), the Commission reserves final determination of the DG tariff and accompanying rates for any rate case filed after June 1, 2018, as the statute dictates. Because the Commission was directed by statute to

[661] April 18, 2018 order in Case No. U-18383, pp. 13-15.
[662] Id. at p. 17.

> develop a DG tariff, the Commission requires the rate-regulated utilities to file the Inflow/Outflow tariff in their next post-June 1, 2018 rate case. As previously noted, the Commission will also permit a rate-regulated utility to file an alternative DG tariff if desired, to enable a thorough evaluation of all viable DG tariff options.[663]

In light of this background, the parties' various proposals for different inputs to the DG tariff are addressed below. This PFD will focus to some extent on the legal arguments contained in the parties' briefs and reply briefs, particularly with respect to determining the outflow credit and how that credit should be applied, as well as the reasonableness of DTE Electric's proposed System Access Contribution (SAC) charge. The statutory provisions at issue include MCL 460.6a(14):

> Within 1 year after the effective date of the amendatory act that added this subsection, the commission shall conduct a study on an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. In any rate case filed after June 1, 2018, the commission shall approve such a tariff for inclusion in the rates of all customers participating in a net metering or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. A tariff established under this subsection does not apply to customers participating in a net metering program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211, before the date that the commission establishes a tariff under this subsection, who continues to participate in the program at their current site or facility.

MCL 460.1177(4):

> Notwithstanding any law or regulation, distributed generation customers shall not receive credits for electric transmission or distribution charges. The credit per kilowatt hours delivered into the utility's distribution system shall be either of the following:
>
> (a) The monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution territory, or for distributed generation customers on a time-based rate

[663] Id. pp.17-18.

> schedule, the monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.
>
> (b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.
>
> MCL 460.1177(5):
>
> A charge for net metering and distributed generation customers established pursuant to section 6a of 1939 PA 3, MCL 460.6a, shall not be reduced by any credit or other ratemaking mechanism for distributed generation under this section.

In light of the foregoing, and in order to limit the number of extraneous issues, the PFD makes the following initial findings of fact and conclusions of law: (1) the Commission has great discretion under MCL 460.6a(14) to fashion an equitable, COS-based DG tariff (e.g., billing mechanism); (2) the Commission has determined that the inflow/outflow method is consistent with the requirements of Section 6a(14) and should therefore be implemented;[664] (3) Neither Section 6a(14) nor Section 177(5) requires or prohibits a grid charge or SAC for DG customers; however, any charge must be demonstrated to be equitable and COS-based; (4) while the Commission has determined that the outflow credit could be an amount other than those defined in MCL 460.1177(4)(a) or (b), the only proposals in this case that conform to those subsections, and that provide defined values for the outflow credit, are those presented by DTE Electric and the Staff.

Although other parties make recommendations for alternatives to the outflow credit proposed by the Staff and DTE Electric, the PFD finds that there is insufficient evidence in this record to, for example, implement an avoided cost rate (an updated avoided cost

[664] Accordingly, MEC/NRDC/SC's rather dense argument that the inflow/outflow method does not comport with either MCL 460.6a(14) or with the DG provisions under Act 295 is rejected.

rate for DTE Electric has not been determined); apply additional, unquantified capacity credits (e.g., value of solar, distribution capacity credits, avoided externalities); or add a credit for avoided line losses. Thus, the outflow credit section will address only DTE Electric's and the Staff's recommendations under Section 177(4).[665]

In addition, several parties make requests that are outside the scope of the determinations that must be made here or that are not within the Commission's authority to grant. Thus, proposals including, but not limited to, lifting the 1% cap on DG, delaying the implementation of the tariff, or the approval of a market transition adder, among many others, are not addressed here.

Finally, the wisdom of replacing net metering with a distributed generation program pursuant to Acts 341 and 342, is a matter well outside the bounds of this proceeding.[666]

2. Inflow Charge

None of the parties appears to seriously dispute that the charge for the electricity flowing into the DG customer's premises should be the full-service retail rate for the rate schedule for that particular customer. This is consistent with the Staff's DG report, and as noted, no party seriously disputed this issue. Therefore, this PFD recommends that the inflow charge be set at the DG customer's full-service rate.

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[665] DTE Electric's proposed inflow/outflow tariff is described in Mr. Serna's testimony and can be found in in Exhibit A-16, Schedule F10. The Staff's proposed DG tariff can be found at

[666] Issues concerning the value of the contribution of customer owned DG versus the cost, and the extent to which non-DG customers subsidize DG customers (if at all) were hotly debated in this proceeding. To provide some scale to the company's claims, the ALJ notes Mr. Serna's testimony: "Across a survey of five states and six utilities, and with cost shift studies conducted by various parties including utilities, external experts, and state utility commissions, the estimated range of distributed generation induced annual cost shift is $444 to more than $1,700 per [non-DG] customer." 8 Tr 3594. Although somewhat dubiously sourced, assuming this information were accurate, the purported subsidy paid by non-DG customers would range from about $0.50 to $1.90 (if Michigan were as sunny as Arizona) per customer per year.

3. Outflow Credit

a. Credit Amount

Mr. Serna explained that "Inflows are defined as each unit of energy (in kWh) consumed by a customer from the distribution system. Outflows are defined as each unit of energy (in kWh) exported from the distributed generation customer to the distribution system." In DTE Electric's proposal, "[t]hey are treated separately, with total inflow charged at a given "inflow" rate and total outflow credited at a separate "outflow" rate based on their respective determinants."[667]

Mr. Dennis testified that:

> For all energy that a DG customer outflows (i.e. sends on to the Company's distribution system), the DG customer will receive a credit. The outflow credit is the monthly average real-time locational marginal price for energy at the DTE Electric-appropriate load node. Outflow credits can be used in each billing period to offset power supply charges of the bill. Should the outflow credits accumulated in a billing period exceed the power supply portion of a customer's bill, the excess credit amount will be banked and be able to be used in future billing periods to offset power supply charges. Credit balances will be carried forward indefinitely. If a customer ceases to participate in the Distributed Generation Program, any remaining credit balance will be forfeited.[668]

Mr. Serna explained why LMP was preferable for pricing the outflow credit. According to him:

> The LMP is the actual cost at which energy is traded on wholesale markets. Producers whom do not sign offtake agreements for their production typically sell production into wholesale markets at the prevailing LMP. They have no obligation to produce at a given time or volume. Similarly, distributed generation customers make no commitment to DTE as to the volume and timing of their output. The market construct which most closely aligns with the production behavior of a distributed generator is the LMP.[669]

[667] 8 Tr 3596.
[668] 8 Tr 3875.
[669] 8 Tr 3601-3602.

Mr. Serna added that LMP is a superior compensation mechanism, to power supply less transmission, because LMP only has two components: fuel and purchased power. "Given the unpredictability of distributed generation customer outflow, either due to higher load on-site or lower than expected production, no capacity requirement is offset by the distributed generation and net metering customer. Without capacity, the remaining power supply cost is fuel and purchased power, a category effectively represented by the LMP."[670]

Although the Staff recommends updating the outflow credit once more data is available, Mr. Ozar testified that:

> *For this initial case*, it is reasonable for the Commission to set outflow compensation at the power supply component of the DG customer's retail rate, excluding transmission. This approach is simple, understandable to customers, creates a close connection between the new compensation rates under the Inflow/Outflow billing method and existing compensation under NEM, and yet avoids the primary subsidy related to NEM which is the inclusion of the distribution charge (of the underlying sales rate schedule) in the outflow compensation formula. Vis-à-vis DTE's requested de-minimis compensation, use of the power supply component of the retail rate, excluding transmission, results in a more measured pace of adjustment from the existing effective level of compensation under NEM. This is especially relevant for existing true NEM customers that will be required to migrate to the new Inflow/Outflow tariff upon its adoption.[671]

In his rebuttal testimony, Mr. Serna proposed an alternative that would include some compensation for capacity:

> The Company has further considered the comments and has a proposal to allow future distributed generation customers to receive a capacity credit. The Company is proposing that for future distributed generation customers that participate both in Rider 18 and in the Company's Dynamic Peak Pricing (DPP) Rate Schedule D1.8, the Company will provide a capacity credit payment. The Company's capacity credit proposal will be contingent on Commission approval of two key elements:

[670] 8 Tr 3602.
[671] 8 Tr 3433.

> 1. Currently customers who take service under rate D1.8 are not allowed to participate in any other riders. The Company is proposing to make an exception and allow customers under D1.8 rate to participate in the new proposed distributed generation rider, as a condition of implementing a capacity credit.
>
> 2. The Company's Rate Schedule D1.8 capacity credit proposal is also contingent on the Commission accepting the outflow rate proposed by the Company in this proceeding. As explained by Company Witness Dennis, DTE Electric's time of use rates were not designed to accurately reflect what DG customers should be compensated for outflow.[672]

This PFD finds that the Staff's proposal for calculating the outflow credit, based on power supply less transmission is reasonable and well supported by the record. As the Staff points out, the company's outflow compensation based on LMP, as originally proposed, assumes that DG outflows have zero capacity value. The Staff further explains:

> Mr. Ozar points to a crucial difference in how the DG customer is viewed by the Company and Staff. Mr. Ozar states that if one focuses solely on the individual DG customer, which is apparently the perspective taken by the Company, it "will lead to the erroneous conclusion '...that there is no tangible capacity value or capacity offset provided by the distributed generation'." (8 TR 3430.) Instead, evaluation of the capacity value of a small customer DG program on a coincident aggregate program basis will reflect the capacity value of the entire program itself as a virtual generator. *Id*. Once this capacity value, on a program- wide basis can be established, it can be incorporated into the outflow compensation formula and allocated to individual customers. *Id*. Mr. Ozar further explains that the Commission does not set utility rates on a single customer basis, but instead considers the whole customer class when setting rates. Id. Similarly, the capacity value of a DG program should not be determined based on the capacity value, if any, of a single customer, but should be based on the program as a whole.[673]

While there appears to have been some interest in DTE Electric's alternative proposal, presented in Mr. Serna's rebuttal testimony, the PFD finds that it was presented

[672] 8 Tr 3659. Additional information about the mechanics and pricing of this alternative can be found at 8 Tr 3660-3661.
[673] Staff's initial brief, pp. 100-101.

too late in the proceeding to be fully vetted. Thus, this potential alternative, which does recognize and value DG capacity to some extent, should be explored in a future proceeding. As the Staff recommends, once more meter data is available from DG customers, the parties can undertake a power-outflow study that will allow for more precise valuation of DG energy outflow. In its reply brief, DTE Electric indicated that it was in agreement with the Staff's recommendation.

Based on the forgoing discussion, this PFD finds that the Staff's recommendation, to base the outflow credit on the power supply charge less transmission is reasonable and should be adopted.

b. Netting of Excess Generation

Mr. Serna testified that AMI meters that are now installed across DTE Electric's service territory are capable of accurately measuring all inflows and all outflows of electricity, adding that "[t]he most precise accounting of the inflow/outflow mechanism is over an instantaneous time-period. In practice this consists of addressing total inflows and outflows as distinct categories for the billing period, capturing each incremental unit of both and representing the truest view of this bidirectional relationship."[674] No party appears to dispute that AMI meters have the technical capability to measure inflow and outflow on a virtually instantaneous basis. The only issue with respect to how or if inflow and outflow are netted appears to be a legal question.

DTE Electric contends that, based on the plain language of Sections 177(4) and 177(5), read *in pari materia*, there can be no netting of inflows and outflows for DG. DTE Electric points to MCL 460.1177(4) which states "[t}he credit per kilowatt hours *delivered*

[674] 8 Tr 3606.

into the utility's distribution system . . ." arguing this means all kilowatt hours delivered, and not simply excess kilowatt hours. DTE Electric maintains that its interpretation of Section 177(4) is supported by Section 177(5), which provides, "A charge for net metering and distributed generation customers established pursuant to section 6a of 1939 PA 3, MCL 460.6a, shall not be reduced by any credit or other ratemaking mechanism for distributed generation under this section."[675]

DTE Electric admits that the Commission addressed this very issue in the April 18, 2018 order in U-18353, but nevertheless asserts that:

> [T]he applicable statutory language ("The credit per kilowatt hour for kilowatt hours delivered into the utility's distribution system shall be either of the following…") plainly indicates that the credits do not apply to generation used onsite. This plain language also reflects that the customer credit choices set forth in MCL 460.1177(4) apply to ALL kilowatt hours "delivered into the utility's distribution system," not just the net outflows (8T 3639-44). The Legislature has also twice (once in 2008 PA 295 and again in 2016 PA 342) made clear that there cannot be credits for transmission or distribution associated with net metering and/or distributed generation.[676]

The Staff counters that:

> The Company's position that all power outflow be compensated at the LMP violates the plain language of the provision which deals with the compensation for excess power generated beyond inflow. Further, of the two compensation methods for excess outflow provided in Section 177(4), although Staff's recommended compensation formula superficially appears to coincide with option (b) under PA 341 Section 177(4), it is critical to note that Section 177(4) only applies such compensation formula to excess power outflows that are carried forward to future billing periods, and that the balance of power outflows are netted within the billing period on an energy basis (i.e. at the full retail rate).[677]

The Staff further explains that the company's interpretation of Section 177(4) is in conflict with itself because, although the company has determined that Section 177(4) is

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[675] DTE Electric's initial brief, pp. 147-148.
[676] Id. at 150.
[677] Staff's initial brief, pp. 89-90.

the sole means by which compensation for outflows can be established, the company fails to acknowledge that it failed to focus on the entirety of 177(4):

> If the *quantity of electricity generated* and delivered to the utility distribution system by an eligible electric generator during a billing period *exceeds the quantity of electricity supplied* from the electric utility or alternative electric supplier during the billing period, the eligible customer *shall be credited* by their supplier of electric generation service *for the excess* kilowatt hours generated during the billing period. MCL. 460.1177(4). (Emphasis added).[678]
>
> * * *
>
> In contrast, the Company makes its case by narrowly focusing on the concluding sentence of Section 177 (4): "The credit per kilowatt hour for kilowatt hours delivered into the utility's distribution system shall be either of the following: (a) The monthly average real-time locational marginal price...(b) The electric utility's or alternate electric supplier's power supply component, excluding transmission charges..." [MCL 460.1177(4).] Only by ignoring the definitions set forth in the opening sentence of Section 177(4) is the Company able to interpret the phrase "for kilowatt hours delivered into the utility's distribution system" as universally applying to any or all power outflows. A universal application of the excess outflow compensation provision to all outflow renders meaningless the preceding language in Section 177(4) that defines which power outflows qualify for credits that can be carried over into future billing periods.[679]

DTE Electric correctly points out that:

> Effect should be given to every phrase, clause, and word in the statute 'read and understood in its grammatical context,' and the statute 'must be read as a whole unless something different was clearly intended.' … the Commission 'must give effect to every word, phrase, and clause in a statute and avoid an interpretation that would render any part of the statute surplusage or nugatory.' *Johnson v Recca*, 492 Mich 169, 177; 821 NW2d 520 (2010).[680]

The ALJ agrees with the Staff, that the plain language of MCL 460.1177(4), when read in its entirety, makes clear that the outflow credit, whatever based on LMP or power

[678] Id. at 92.
[679] Id. at 96-97.
[680] DTE Electric's initial brief, p. 148, quoting the November 21, 2017 order in Case No. U-18248, pp 72-73, which in turn quotes *Dep't of Environmental Quality v Worth Twp*, 491 Mich 227, 237-238; 814 NW2d 646 (2012).

supply less transmission, applies only to *excess* generation above monthly consumption for the billing month (e.g., "the quantity of electricity generated and delivered to the utility distribution system by an eligible electric generator during a billing period [that] *exceeds* the quantity of electricity supplied from the electric utility *during the billing period* shall be credited[.]") The ALJ also agrees with the Staff that subparts (a) and (b) describe alternative pricing mechanisms and that the language at the beginning of Section 177(4) cannot be ignored. Again, as DTE Electric asserts, every word and phrase of the statute must be given effect to avoid rendering any portion of the statute surplusage. Moreover, the ALJ finds that this interpretation of the statute does not conflict with Section 177(5), which only comes into play if "A charge for net metering and distributed generation customers [is] established pursuant to section 6a of 1939 PA 3, MCL 460.6a[.]" Because the SAC charge was rejected, Section 177(5) does not apply. Consistent with the analysis above, the Commission should approve the Staff's recommendation with respect to netting inflows and outflows.

4. System Access Contribution Charge

DTE Electric proposes an SAC charge to be applied to DG customers who are not on a rate with demand-based charges. Mr. Serna testified that the proposed SAC "assigns a cost per kW AC of nameplate system capacity based on the system-cost responsibility of distributed generation customers." According to Mr. Serna, charges based on volume are "an insufficient but serviceable approach" to covering the utility's fixed costs when loads are stable and predictable. However, "[w]hen stability and predictability are no longer assured, the recovery of costs must more closely match their incurrence." Mr. Serna added that because DG customers always have the option of taking service from the company, these customers do not pay the full cost of the distribution facilities that provide this service.[681]

Mr. Dennis testified that:

> The SAC is a monthly per kW of installed nameplate capacity charge. The proposed SAC charges per kW of installed nameplate generation on the customer's site is calculated on Exhibit A-16 Schedule,F9. Lines 1, 2, and 3 of the exhibit show annual average kWh of inflow, outflow, and generation based on 2017 historic customer data for customers with generation meters. Using this data, line 4 calculates the amount of annual average on-site usage, including energy inflowed and generation used onsite. As part of the residential and secondary commercial distribution rate design, the Company in this case (and in past cases) is moving toward universal consumption based (kWh) distribution charges for all residential secondary customers, and for all commercial secondary customers with a per kWh distribution charge. The Company is doing this gradually, capping the distribution charge increase for any rate schedule in each rate case. Line 5 of Exhibit A-16,Schedule F9 shows the universal distribution charge that would exist if all residential secondary paid the same distribution charge, and if all commercial secondary customers paid the same distribution charge. Using these charges, line calculates the total average DG site distribution revenue requirement, and line calculates the amount of distribution revenue that would result from the total average inflow. The difference between these two values (line 6 less line 7) is shown on line 8, which represents the annual distribution revenue deficiency. Line reflects the monthly distribution revenue deficiency. Line 10 shows the average installed nameplate capacity ratings, based on the same customers used to gather the inflow, outflow, and generation data. Line 11 then calculates the monthly SAC per kW of installed nameplate capacity. Separate SAC charges are developed for residential secondary DG customers and commercial secondary DG customers. [682]

Under Mr. Dennis's calculation, he SAC would be equal to $2.31/kW per month for residential customers and $2.28/kW per month for small commercial customers.[683]

DTE Electric's proposed SAC charge did not garner support. Mr. Lucas testified that through the SAC, "the Company intends to charge DG PV customers for their full

[681] 8 Tr 3598-3599.
[682] 8 Tr 3875-3876.
[683] Exhibit A-16, Schedule F9.

imputed load rather than their actual inflow from the grid. This means that an average DG customer would be charged the same distribution costs whether they had a PV system or not."[684] He added, "[b]y singling out DG PV customers and subjecting them to a charge based on imputed load rather than actual load, the SAC is clearly discriminatory."[685]

Mr. Rábago testified that "the SAC charge is constructed to impose a charge on DG customers for the energy not used by a hypothetical customer with a hypothetical DG facility and a hypothetical pattern of electricity usage, which is then allocated based on system capacity rather than energy usage (real or hypothetical)," adding "[a]s a result, the SAC charge is based on the flawed premises that non-use of grid-supplied energy creates a basis for a charge under cost-based regulation, and that charges on self-generators should be based on sub-group deviations from forecasted usage which are then imposed on nameplate capacity rather than usage."[686] Mr. Jester opined that the SAC "is founded on the Company's notion that it is entitled to the revenue it will otherwise forego when a customer adopts distributed generation. The Company has no such entitlement and the 'System Access Contribution' would therefore violate the requirement of MCL 460.6a(14) that the distributed generation tariff reflect 'equitable cost of service'"[687]

Mr. Kenworthy contends that imposition of the SAC amounts to double recovery because "[w]hen a DG customer exports energy to the grid, it is consumed by neighboring customers who compensate the utility for that service at the full retail rate, inclusive of

[684] 6 Tr 2409.
[685] Id. at 2410.
[686] 6 Tr 2497-2498.
[687] 6 Tr 2208.

fully-loaded delivery charges." Thus, "to the extent that DTE's proposed SAC charge is meant to compensate the utility for delivering the DG customer's exported power, it represents a double-recovery of the utility's costs to deliver the DG exports."[688]

Ms. Sherman and Mr. Koeppel also oppose the SAC. Ms. Sherman testified that the SAC "essentially creates a demand charge based on the size of the distributed generation system for those customers. In my opinion, the proposed SAC represents a significant barrier to the deployment of distributed energy generation."[689] And Mr. Koeppel characterized the SAC as an "unfair burden" on DG customers, "but also may tip the program into being unaffordable for low-income ratepayers who might otherwise have been able to participate."[690] Mr. Krause testified:

> The SAC is intended to collect distribution based on the imputed energy that would have provided if the customer had not installed DG. However, as pointed out in Staff's report, usage can increase or decrease for any number of reasons such as change in household size, EWR, or the addition of a new end use, like an electric vehicle. It is not appropriate to impute usage that would have been had not the customer installed DG, just as it would be inappropriate for any other customer who reduces their usage for any other reason. The measured amount of total inflow, whether by demand or energy, is the appropriate measure for determining distribution usage not just for DG customers, but for all customers.[691]

In briefing, the parties opposing the implementation of the SAC generally relied on the testimony of their respective witnesses. As MEC/NRDC/SC summarizes:

> [DTE Electric's] calculation shows that the SAC does not charge DG customers based on the load they actually place on the system, or the revenue requirement of the class attributable to the DC customers' loads. Rather, the proposed SAC would collect revenue from DG customers based on the amount of load that distributed generation customers *remove* from DTE's distribution system by consuming their own self-generation behind the meter and that *reduces* the revenue requirement allocated to the

[688] 6 Tr 2336.
[689] 8 Tr 3530.
[690] 5 Tr 1574.
[691] 8 Tr 4234.

class. Moreover, there is no connection between revenue requirement created by loads at specific peak hours and a customer's nameplate generation capacity.[692]

In its reply brief, DTE Electric insists that the SAC is cost-based, and it is required because "utility infrastructure costs would remain unrecovered and be shifted onto the remaining traditional customers without the additional SAC charge."[693]

The PFD agrees with the parties opposing the SAC. The record supports the claims of the opposing parties that the SAC charge is not COS-based, despite the company's protestations to the contrary. Although the SAC charge is ostensibly designed to recover costs associate with DG customers' more extensive use of the grid, as attested to by Mr. Serna and Mr. Mueller,[694] as multiple parties point out, the cost is actually designed to recover lost revenues resulting from customers' decisions to invest in DG. As ELPC argues, "DTE's methodology explicitly relies on 'revenue deficiencies' and not cost of service[,]" pointing to "Ex. A-16, Schedule F9, Lines 8-9 (calculating 'annual distribution revenue deficiency' and 'monthly distribution revenue deficiency' for purposes of calculating the SAC). Lost revenues are not the same thing as cost of service."[695, 696]

Because the DG tariff approved under Section 6a(14), must be COS-based, and a tariff including an SAC is not, it is not necessary to reach a determination on whether the SAC charge is "equitable" as the statute also requires. Briefly, however, and for completeness, the SAC charge is also not equitable. The fact that the SAC charge is not based on a DG customer's actual usage of DTE Electric's distribution system but rather

[692] MEC/NRDC/SC's initial brief, pp. 129-130.
[693] DTE Electric's reply brief, p. 209.
[694] 8T 3814-3817.
[695] ELPC's initial brief, p. 13.
[696] As noted above, although DTE Electric provides a litany of additional costs purportedly caused by DG customer use of the grid, these costs were in no way quantified.

on the size of the customer's system. As the Staff points out, "In addition to the flaws in the methodology, the Company proposes to charge only DG customers based on this method. To treat DG customers differently would effectively treat them as a separate class, which is inappropriate, as their usage is within normal variation of the residential class."[697]

5. Other Distributed Generation Issues

As discussed above, the various parties weighing in on this issue raise a number of issues that are beyond the scope of this proceeding or the Commission's authority, or that are not supported by the underlying statutes. The following issues are, however, necessary to a final resolution of the multitude of issues concerning Rider 18.

a. Eligibility of Net Metering Customers to Increase System Size

In its initial brief, the Staff recommended that if a customer expanded his or her system before Act 341 and 342 went into effect in April 2017, then that customer's entire system should be grandfathered into the net metering program for ten years beginning with the date of the expansion. DTE Electric contends that the Staff's proposal conflicts with the company's current Rider 16 tariff, which states that the contract term provides for "a single continuous period up to 10 years."

The PFD agrees with the company that the current tariff provisions should prevail and that from the beginning, the net metering program was set for 10 years.

b. Customer Termination or Withdrawal from the Program

DTE Electric proposed that if a customer decides to end his or her participation in the DG program, any remaining credits in the customer's account should be forfeited. In

[697] Staff's initial brief, p. 87.

its reply brief, the company agreed in part. The company's position now is that customers moving out of their residences should receive a refund of any unused credit balance. However, customers who end their participation in the program and remain in the residence, will have any banked credits applied to future bills.

This PFD finds the company's proposal to be reasonable and recommends that the DG tariff be amended to reflect the above-stated provision.

c. Customer Interconnection Cost Reporting

Ms. Baldwin testified that, pursuant to MCL 460.1175(1), DG customers are now required to pay all interconnection costs. Ms. Baldwin indicated that this is a new requirement and information about these costs (including service transformer and secondary line conductor upgrades) would be helpful to the Staff, potential DG customers, and DG installers. Ms. Baldwin proposed language to be included in Rider 18 that sets out this reporting requirement.[698]

DTE Electric objected to this requirement citing concerns about customer privacy. This PFD finds that DTE Electric and the Staff should work together informally to find a mutually agreeable way to both provide the information the Staff requests (in some aggregated form perhaps) and protect customer privacy.

H. Distributed Generation Rider (Rider DG/Rider 14)

To avoid confusion with the new DG program under Rider 18, the company and the Staff agreed to change the name of "Rider DG" to "Rider 14." This tariff change was not opposed and should be approved.

[698] 8 Tr 4175.

Ms. Baldwin testified that the Staff does not support the company's proposal to limit Rider DG to non-renewable energy generators. According to Ms. Baldwin, although Rider 14 limits the size of the generator to 100 kW, it does not limit generation to the size of the customer's annual energy usage, as Rider 18 and Rider 16 do. Thus, "Rider DG may allow a customer the opportunity to have an on-site project which would not otherwise fit under the requirements of the new proposed DG Rider 18."[699]

DTE Electric contends that:

> There is no requirement for the Company to offer additional customer-owned renewable generation tariffs, such as Rider DG. 2016 Public Acts 341 and 342 contain explicit direction on creating a distributed generation program and tariff for customer-owned renewable generation, and the law outlines specific conditions under which customer owned renewable generation resources qualify for a distributed generation program. The Company is not presently choosing to provide additional programs at this time.[700]

DTE Electric again cites *Union Carbide* and management prerogative as support for the company's position on offering additional customer-owned renewable programs, which it chooses not to do.

The PFD agrees with the Staff that Rider 14 (f/k/a Rider DG) should remain open to customers who do not qualify for Rider 16 or Rider 18. As discussed above, *Union Carbide* does not apply to this circumstance, in light of the fact that the issue concerns an existing tariff (and rate) which should be made available to customers who do not qualify

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[699] 8 Tr 4176.

[700] DTE Electric's reply brief, p. 234. At one point in testimony, the company took the position that customer-owned renewable energy generation under Rider DG/Rider 14 should be added to the renewable generation under Rider 18 and Rider 16 and count towards the 1% cap under MCL 460.1173(3). Given how distant customer-owned renewable energy generation is from the cap of 1%, this issue is more academic than anything else. *See, e.g., Distributed Generation Program Report for Calendar Year 2017,* p. 5, which shows that DTE Electric's DG program currently has 1,675 customers enrolled with 78% of space remaining under its 1% cap. In any event, Section 173(3) specifically refers to the "distributed generation program" size with respect to the cap, and it appears that DTE Electric has chosen not to pursue this position in its briefing.

for Rider 16 or Rider 18. Thus, except for the name change to Rider 14, the Rider DG tariff should not be revised or closed to additional renewable generators.

I. Net Metering (Rider 16)

Mr. Serna testified that DTE Electric proposes to add language to the current net metering tariff (Rider 16) to clarify that net metering will be closed to new customers after Rider 18 is approved, except for customers that have a completed application pending with the company before the new DG tariff is approved. Mr. Serna added that if a customer has submitted an application that the company finds deficient, any deficiencies in the application will have to be remedied prior to the time Rider 18 is approved. Also, the proposed tariff changes specify that any customer wishing to participate in net metering most complete the installation of a generating system within six months of application approval.

Ms. Baldwin testified that the Staff had concerns that DTE Electric's proposed language could conflict with the Commission's April 18, 2018 order in Case No. U-18383, which does not reference an "approved" application. Based on the Commission's order, Ms. Baldwin recommended changing the language to state that the rider is only available to customers participating in the program.

In rebuttal, Mr. Dennis agreed that the use of the word "approved" could cause confusion, but noted that "participating" could also be misconstrued. Alternatively, Mr. Dennis recommended that the language in Rider 16 state: "This Rider is available only to customers with a completed application pending prior to April _____, 2019."[701] The Staff

[701] 8 Tr 3901.

agreed in its initial brief.[702]

Dr. Sherman also testified that Mr. Serna's proposal does not comport with the Commission's directive in Case No. U-18383, noting that the order allows customers who have submitted applications before the DG tariff is approved to correct any deficiencies within 60 days from the date of notification of any omissions or errors. Dr. Sherman explained that:

> it is critical that customers who submit their applications prior to the final Order in this rate case are given sufficient time to correct any deficiencies in their applications. As described above, the Commission ruled in the final Order in U-18383 that applicants would be given 60 days from the date of notification by the utility to fix any deficiencies in their application. It is important that customers be afforded this time given that there may be a need to ask questions of the Company, provide new materials, or make additional measurements. It is unreasonable to expect that an applicant would be able to control the timing of any necessary back-and-forth discussion with the Company regarding deficiencies in their application such that those deficiencies are fixed prior to the final Order in this rate case.[703]

Although Dr. Sherman did not provide any proposed language for the tariff, her point, that the language proposed by the company, even as amended in Mr. Dennis's rebuttal, does not comport with the Commission's determination in the April 18, 2018 order in Case No. U-18383, p 17:

> The Commission agrees with the Staff's recommendation in the DG Report that, under the interim DG program, a customer will be considered "participating" in the program if the customer has a completed application pending before the utility prior to the effective date of the new DG tariff approved in a rate case filed after June 1, 2018. For DG applications submitted prior to the effective date of the new DG tariff, the utility shall notify the applicant within 10 working days from the date the application is submitted whether the application is complete or deficient. If complete, the application shall be processed, and the customer will be considered enrolled in the utility's DG program. If the application is deemed deficient,

[702] Staff's initial brief, p. 141.
[703] 8 Tr 3527.

> the applicant shall be given 60 days from the date of notification by the utility to cure the deficiency. If the applicant fails to cure the deficiency, the application will be considered void.

This PFD finds that Ms. Sherman's concerns are well taken. The language in Commission's order appears to say two things: (1) a customer is "participating" in the interim DG program (i.e., net metering) if the customer has a "completed" application pending before the utility at the time the DG tariff is approved; (2) a customer who has an application filed with the utility before the effective date of the DG tariff may still be allowed to participate in net metering if the application is found deficient, provided the applicant cures the deficiency within 60 days.

While the ALJ finds it unlikely that any customers who wish to participate in the more favorable interim DG program will wait until the last minute to file an interconnection and net metering application, for the handful who might do so, both provisions should apply. The parties appear to be in agreement that a customer with a completed application is "participating" in the interim DG program for 10 years. In the rare case of the applicant who waits until the last minute to apply, and whose application is found deficient, those applicants as well should be considered "participating" in the interim DG program as long as the deficiency is timely addressed.

There are certainly other circumstances that might occur during the transition from the interim DG program to the program under Rider 18 that cannot be anticipated or addressed here. For those customers who may be affected, the Commission's informal and formal complaint processes are available.

J. Retail Open Access Rider EC2-Return to Full Service

Mr. Bloch explained that the return to full service (RASR) provisions in the company's current electric choice tariff (EC2) require non-residential choice customers to provide written notice to the company by December 1 if they intend to return to bundled service the following summer (i.e., during the June through September billing months). Customers who notify DTE Electric that they intend to return must take service for 12 consecutive months after their return.[704] If a non-residential customer fails to notify the company in accordance with the RASR requirements, that customer will be subject to the higher of the tariffed rate plus 10%, or market power price (MPP). Likewise, customers who fail to fulfill their two-year commitment to remain as choice customers will be charged the higher of MPP or the tariffed rate until the two-year time is completed.[705]

Mr. Bloch further explained that residential customers who return to bundled service are not subject to MPP charges and they are not required to stay on choice for two years. Instead, these customers must remain on choice for a minimum of one billing cycle and once they return to service, they must remain bundled customers for a minimum of one year.[706] In this proceeding, DTE Electric is proposing to apply the same, less restrictive, RASR provisions to non-residential customers returning to service as are applied to residential customers.

Mr. Bloch observed that when the original RASR requirements were established, electric choice was unlimited and the company needed time to plan for power supply for returning customers. Since the enactment of 2008 PA 286 and Act 341, choice is limited

[704] 5 Tr 1228; Exhibit A-16, Schedule F10 revised.
[705] Id.
[706] 5 Tr 1229.

to 10%, and alternative electric suppliers (AESs) are required to demonstrate that they have sufficient forward capacity to meet their customers' requirements. An AES that fails to demonstrate sufficient capacity will be required to pay DTE Electric a capacity charge. Accordingly, the company no longer needs to plan to meet the capacity needs of returning choice customers and the more stringent RASR provisions are unnecessary.[707]

On behalf of Energy Michigan, Mr. Zakem recommended some additional flexibility to the RASR provision, explaining that along with the changes to the energy landscape that Mr. Bloch discussed, the establishment of the Midcontinent Independent System Operator (MISO), was also a significant transformation to the energy landscape. According to Mr. Zakem:

> [I]n April of 2005 . . . MISO began to dispatch all resources in its region to serve all loads in its region. Individual suppliers – whether utilities or AESs – no longer "served" energy to their customers. Instead, MISO dispatched virtually all energy resources to serve all customers, and the responsibility for "serving" was translated from a physical responsibility into a financial responsibility from supplier to MISO and into a financial responsibility from customer to supplier – whomever that supplier was designated to be.
>
> As part of the change to a regional market, the local utility became a "supplier of last resort." With the new energy market structure in MISO – centralized dispatch of all resources to serve all loads – the customer will always receive energy. The questions are which supplier does the customer pay, how much, and how much does the supplier pay MISO?[708]

Mr. Zakem added that because of the institution of the annual MISO capacity auction, "all suppliers will have access to sufficient capacity through MISO. . . . Thus, when a customer 'returns to full service,' there is no issue of the utility not having access to sufficient capacity – via the MISO auction re-allocation – or to sufficient energy – via

[707] 5 Tr 1230-1231.
[708] 7 Tr 3089.

the MISO energy market. The only question is price."[709] As a result, Mr. Zakem testified that there is no "subsidy" for capacity when a customer moves to choice or back to bundled service.

Mr. Zakem explained that both flexibility for electric choice customers and protection of the utility from short-term gaming by choice customers need to be addressed, regardless of how the industry is structured. Mr. Zakem testified that he agreed with DTE Electric's proposal to eliminate the minimum stay on choice but for a customer returning to bundled service, the company proposes a minimum one-year stay. Mr. Zakem opined that this unnecessarily reduces customer flexibility because "the current industry structure can accommodate a short-term stay at no additional cost to the utility, even more simply than the short-term option that DTE is eliminating."[710] Accordingly, Mr. Zakem recommended that DTE Electric retain the two options, for a 12-month commitment (Option 1) and short-term service (Option 2), as set forth in his recommended tariff revisions to the EC2 tariff.[711]

Mr. Zakem also addressed language in the EC2 tariff that concerns DTE Electric's responsibilities to provide metered data to the choice customer and the customer's energy supplier. According to Mr. Zakem, [t]he current tariff is vague to the point of difficulty in reasonably determining (a) what the standards are to which DTE must perform and (b) whether DTE has reasonably met such standards.[712]

Mr. Zakem pointed out that because DTE Electric provides distribution services to all customers, choice and bundled, it should be providing the same meter data reporting

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[709] 7 Tr 3090.
[710] 7 Tr 3091-3092.
[711] 7 Tr 3092; Exhibit EM-4.
[712] 7 Tr 3094.

service to both sets of customers in an equal, non-discriminatory fashion. Because the current tariff language is unclear, whether meter services are provided equally cannot be determined. Mr. Zakem therefore recommended a change to the company's tariff that provides more specificity and better delineates the company's responsibilities with respect to choice customer and provider access to meter data.

In rebuttal, Mr. Bloch testified that the company's proposed changes to the RASR provision are intended to simplify the return to service rules. According to Mr. Bloch, "keeping a short-term option provides no additional customer flexibility, and costs the Company to maintain that option[,]" noting that because the company has reached its 10% cap on choice, any customer returning to bundled service and wishing to return to choice must join the queue as required in the April 28, 2017 order in Case No. U-15801, "and few additional customers have been awarded an allotment to participate [in choice] since then."[713] Mr. Bloch further testified that no customers are currently taking service under Option 2.

Mr. Bloch testified that both full-service and choice customers with advanced electric meter (AEM) technology have access to their demand and usage data through the company's website, and choice customers can provide this data to key personnel inside and outside their business, including alternative suppliers. Mr. Bloch testified that customers without AEM meters do not have web access to interval data at this time, and customers with AMI may contact the company for this information or access it through the DTE Energy Insight App.[714] Mr. Bloch explained that as part of Case No. U-18485, the

[713] 5 Tr 1260.
[714] 5 Tr 1261.

company is developing a web-based product that will allow customers with AMI to download usage data and send it directly to a third party.

Mr. Bloch testified that alternative suppliers receive customer meter data for both AEM and AMI after each bill is generated, typically on a monthly basis, when the company automatically sends the data to the alternative supplier in an .XML file. Mr. Bloch disagreed that any changes or clarifications to the tariff are necessary at this time, noting that the language concerning meter data will be updated after the conclusion of Case No. U-18485.[715]

In rebuttal testimony on behalf of the Staff, Ms. Cantin stated that the Staff agrees with Mr. Bloch's proposal to make RASR provisions less restrictive for customers returning to bundled service. Ms. Cantin further testified that the Staff does not oppose Mr. Zakem's recommendation to retain two options in the RASR tariff, however her testimony was consistent with Mr. Bloch's explanation that "gaming" (by switching to bundled service for a short time when market prices are high, then switching back to choice when market prices are low) is possible at this time given the current waiting list for customers wanting to enroll in choice service.[716] However, if the current 10% cap on enrollment is lifted, then the two options "would retain flexibility for the customer and protect the utility from short-term customer switching."[717]

Ms. Cantin testified that the Staff does not oppose Mr. Zakem's recommendations regarding the provision of meter data, while noting that this is a generally a matter between DTE Electric and the alternative supplier. According to Ms. Cantin, the Staff

[715] Id. at 1262-1263.
[716] 8 Tr 4225-4226.
[717] Id. at 4226.

would only get involved if there were an issue over the data or obtaining the data, but the Staff nevertheless believes that meter data should be supplied in a timely and accurate manner.

Finally, Ms. Cantin testified that the Staff recommends that on Sheet E 6.00, Section E2.6.1(C), the language should be modified to reference "the most recently approved procedures in Case No. U-15801," rather than specifying a date.[718]

In its initial brief, Energy Michigan contends that although Mr. Bloch provided a review of the methods for obtaining meter data, these methods may not be usable or workable for a choice customer, and the tariff itself does not provide any performance standard for the company. "Energy Michigan believes that customers should have the right, as specified in the tariff, to more than merely "request" their data and have it provided in whatever format DTE determines, but rather the customer should have a right to timely and accurate data in a usable format and not be dependent on the benevolence of DTE to obtain it." Energy Michigan contends that the changes it proposes will accomplish this objective.[719]

With respect to DTE Electric's proposed changes to the RASR provisions, Energy Michigan reiterates that it supports the consolidation of the rule for all customers, but nevertheless recommends that the two pricing options be retained in the event that the cap on choice is raised or eliminated.[720]

In response, DTE Electric reiterates that retaining both pricing options in the RASR provision of the EC2 tariff is unnecessary and costly. In addition, the company contends

[718] Id. at 4227.
[719] Energy Michigan's initial brief, p. 8.
[720] Id. at p. 9.

that it is already providing meter data to MISO and marketers can access this information through the MISO website.

This PFD agrees with Energy Michigan that the two pricing options (12-month and short term) should be retained. While DTE Electric contends that the short-term option is not necessary in light of the current status of electric choice, Energy Michigan correctly points out that the cap on choice could be raised or eliminated. DTE Electric also suggests that retaining Option 2 somehow costs the company something; however, it fails to explain why that is the case or what the cost is.

This PFD agrees with DTE Electric; however, that any revisions to the meter data acquisition provisions of the EC2 tariff should be addressed as part of the ongoing proceeding in Case No. U-18485. In the October 24, 2018 order in that case,[721] the Staff, utilities, and stakeholders were directed to specifically address several of the issues Energy Michigan raises here including:

> (1) refinement of what is considered a consistent expectation of "timely manner" for the utility to provide usage data to a customer and the customer's authorized third party following the data request, (2) refinement of what is considered "readily accessible format" that the utilities will use to provide usage data to a customer or the customer's authorized third party following the data request, (3) refinement of what are considered "clear instructions" from the utility to the customer regarding how the customer or the customer's authorized third party can easily access consumption data, (4) clear language from the utility that permits customers to provide electronic signatures to the utility when requesting consumption data or authorizing third parties to receive their customer usage data, and (5) general consistency with the language of the various utility customer data privacy tariffs filed with the Commission in this docket.

[721] Order, pp. 4-5.

Consistent with the discussion above, Energy Michigan should raise data access issues in the data privacy docket.

K. Other Tariff Changes

In its reply brief, DTE Electric highlights the following proposed tariff changes:

(1) Variable distribution rates that are designed to approach a uniform rate for all residential secondary rate schedules, with individual variable rates capped at a 20% increase, in accordance with the Commission's decisions in Case Nos. U-17767, U-18014 and U-18255 (8T 3859, 3867-68).Staff agrees (Staff Initial Brief, pp 131-32).

(2) Modify tariff language, consistent with billing rule R 460.113, clarifying that in cases where the Company is missing interval meter data, customers on residential TOU rate schedules are to be charged the off-peak (lower) rate (8T 3859, 3872).

(3) Modify section C6.5(c)(4) of the Company's rate book to reflect that costs associated with the relocation of Company facilities to accommodate load additions will be treated the same as other line extension costs associated with the load addition. The new language is consistent with Consumers Energy Company's tariff, section C1.6A (8T 3859, 3873).

Noting that these changes were not opposed, DTE Electric requested their approval.[722] The ALJ agrees and recommends that the Commission approve the additional tariff changes described above. In addition, the Staff recommended that the maximum number of events under Rate D1.8 be limited to 14 rather than the 20 events in the current tariff. The company did not oppose this change, therefore it should be adopted.

[722] DTE Electric's reply brief, pp. 235-236.

XII.

OTHER MISCELLANEOUS ISSUES

A. General and Intangibles Study

Mr. Gottschalk explained that DTE Electric used a General and Intangibles (G&I) direct assignment study from 2008 to functionalize G&I plant in this case.[723] According to Mr. Gottschalk, because it has been 10 years since the last study, it is reasonable to direct the company to perform an updated study using the latest available data for use in the company's next rate case. This recommendation was not opposed by the company or other parties to the case. This PFD therefore recommends that the Commission direct DTE Electric to update its G&I direct assignment study for its next general rate case.

B. Low Income Issues

In Mr. Koeppel's testimony and Soulardarity's briefs, the organization raised a number of issues with respect to low income communities and customers. Several of these issues are addressed above. Of the remaining, as DTE Electric points out, Soulardarity's request to deny an increase to residential customer rates must be denied based on COS principles; as DTE Electric explained, its customer service platforms are designed to be more, rather than less, inclusive; and DTE Electric and the Commission's Service Quality Staff regularly meet with customers, including low income customers, about available rate and assistance plans.

[723] See, December 23, 2008 order in Case No. U-15244.

XIII.

CONCLUSION

Based on the foregoing discussion, this PFD recommends that the Commission adopt the findings, conclusions and recommendations set forth above, including the findings and recommendations on rate base, capital structure, cost of capital, and operating revenues and expenses leading to an estimated revenue deficiency of approximately $261,904,000 million (including the termination of Credit A credit) with an authorized return on equity of 10.00% and an overall cost of capital of 5.48%, as well as recommendations regarding various accounting requests, ratemaking mechanisms, cost of service allocations, rate design, and tariff modifications, as well as recommendations for additional reporting and analysis.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Sally L. Wallace

Digitally signed by: Sally L. Wallace
DN: CN = Sally L. Wallace email = wallaces2@michigan.gov C = US O = MAHS PSC OU = MAHS
Date: 2019.03.06 16:54:16 -05'00'

Sally L. Wallace
Administrative Law Judge

ISSUED AND SERVED: , 2019

Michigan Public Service Commission **Appendix A**
DTE Electric Company PFD
Projected Revenue Deficiency (Sufficiency) Case No.: U-20162
Projected 12 Month Period Ending April 30, 2020
($000)

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**Company Projection (Reply Brief)**	**PFD Adjustment**	**PFD Projection**
1	Rate Base	Exh. A-12, Sch. B1	17,152,348	(152,778)	16,999,569
2	Adjusted Net Operating Income	Exh. A-13, Sch. C1	801,737	45,656	847,393
3	Overall Rate of Return	Line 2 ÷ Line 1	4.67%	0.31%	4.98%
4	Projected Rate of Return	Exh. A-14, Sch. D1	5.72%	-0.24%	5.48%
5	Income Requirements	Line 1 x Line 4	980,720	(49,106)	931,614
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	178,982	(94,762)	84,221
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	1.3496	-	1.3496
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	241,561	(127,894)	113,667
9	Revenue Deficiency / (Sufficiency)-Tree Trim Surge	Staff Witness Evans	7,053	(7,053)	-
10	Revenue Deficiency / (Sufficiency)-Total	Line 8 + Line 9	248,614	(134,946)	113,667
11	U-20105 TCJA Rate Impact with New Rates Effective in the Instant Case	Staff Witness Pung			148,237
12	Net Rate Increase	Line 10 + Line 11			$ 261,904

Michigan Public Service Commission **Appendix B**
DTE Electric Company PFD
Projected Rate Base Case No.: U-20162
Projected Average Balances Period Ending April 30, 2020
($000)

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**Company Projection (Reply Brief)**	**PFD Adjustment**	**PFD Projection**
1	Utility Plant in Service:				
2	Plant in Service	Exh. A-12, Sch. B2, L6	21,314,373	(159,344)	21,155,029
3	Plant Held for Future Use	Exh. A-12, Sch. B2, L7	57,923	-	57,923
4	Construction Work in Progress	Exh. A-12, Sch. B2, L8	1,679,418	-	1,679,418
5	Acquisition Adjustments	Exh. A-12, Sch. B2, L9	116,148	-	116,148
6	Total Utility Plant	Sum Lines 2 thru 5	23,167,862	(159,344)	23,008,518
7	Depreciation Reserve	Exh. A-12, Sch. B3, L6	(7,606,777)	7,359	(7,599,418)
8	Net Utility Plant	Line 6 + Line 7	15,561,085	(151,985)	15,409,100
9	Net Capital Lease Property	Exh. A-12, Sch. B4.1, col. (c), L10	6,222	-	6,222
10	Net Nuclear Fuel Property	Exh. A-12, Sch. B4.1, col. (c), L11	112,164	-	112,164
11	Total Utility Property and Plant	Sum Lines 8 thru 10	15,679,471	(151,985)	15,527,486
12	Less: Capital Lease Obligations	Exh. A-12, Sch. B4.1, col. (c), L68 + L80	6,324	-	6,324
13	Net Plant	Line 11 - Line 12	15,673,147	(151,985)	15,521,162
14	Allowance for Working Capital	Exh.A-12, Sch. B4	1,479,201	(793)	1,478,407
15	Total Rate Base	Line 13 + Line 14	17,152,348	(152,778)	16,999,569

MICHIGAN PUBLIC SERVICE COMMISSION **Appendix C**
PFD
Case No.: U-20162

DTE Electric Energy Company
Projected Net Operating Income
for the Test Year Ended April 30, 2020
($000)

		Revenue				Expenses									NOI			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Line No.	Description (Witness)	Sales Revenue	Base Fuel & Purchase Power Rev.	Other Revenue and R2	Total	Fuel and Purchased Power	Other O&M Expense	Depreciation & Amort.	Property Taxes	Other Taxes	State & Local Income	FIT	Other Utility (Income) / Deductions	Total	NOI	AFUDC	Other Operating Income Adj.	Adjusted NOI
	Company Filed																	
1	Operating Income (Initial Filing)	3,309,210	1,385,795	90,345	4,785,349	1,385,795	1,312,396	948,986	275,525	52,234	42,543	44,936	2,134	4,064,549	720,800	32,973	(2,917)	750,856
2	Depreciation - HQ Energy Center							(151)			9	30		(112)	112			112
3	Depreciation - U-18150							(65,238)			4,051	12,849		(48,338)	48,338			48,338
4	Active Healthcare O&M						(1,733)				108	341		(1,284)	1,284			1,284
5	Injuries and Damages O&M						(892)				55	176		(661)	661			661
6	Tax Reform Reg. Liab. Amort.											411		411	(411)			(411)
7	Rounding	-	-	-	-	-	-	-	-	-	-	30	-	30	(30)	-	-	(30)
8	**Operating Income (Initial Brief)**	3,309,210	1,385,795	90,345	4,785,349	1,385,795	1,309,771	883,597	275,525	52,234	46,767	58,773	2,134	4,014,596	770,754	32,973	(2,917)	800,809
9	Sales Revenue - RIA Cus	900			900						56	177		233	667			667
10	Depreciation - HQ Energy Center				-			(89)			6	18		(66)	66			66
11	Tax Reform Reg. Liab. Amort.				-						-	(411)		(411)	411			411
12	Rounding				-						(51)	(30)		(81)	81			81
13	Interest Sync - Initial Brief	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(297)	(297)
14	**Operating Income (Reply Brief)**	3,310,110	1,385,795	90,345	4,786,249	1,385,795	1,309,771	883,508	275,525	52,234	46,777	58,527	2,134	4,014,271	771,978	32,973	(3,214)	801,737
	PFD Adjustments																	
15	Inflation (Welke)				-		(12,338)				766	2,430		(9,141)	9,141			9,141
16	Injuries and Damages (Welke)				-		-				-	-		-	-			-
17	Incentive Compensation (McMillan-Sepkoski)				-		(27,083)				1,682	5,334		(20,067)	20,067			20,067
18	Uncollectibles (Welke)				-		(234)				15	46		(173)	173			173
19	Incremental Charge Forward O&M (Ozar)				-		(1,168)				73	230		(865)	865			865
20	Meter Reading (Matthews)				-		(2,147)				133	423		(1,591)	1,591			1,591
21	Tree Trimming O&M Expense (Evans)				-		13,007				(808)	(2,562)		9,637	(9,637)			(9,637)
22	AFUDC Adjustment (Gerken)				-						-	-		-	-	1,923		1,923
23	Cap Ex. Adj. Impact on Depreciation Expense				-			(7,608)			472	1,498		(5,637)	5,637			5,637
24	River Rouge Unit 3 O&M				-		(17,650)				1,096	3,476		(13,078)	13,078			13,078
25	Weekend Flex / Fixed Bill				-		(1,408)				87	277		(1,043)	1,043			1,043
26	EEI Dues				-		(1,269)				79	250		(940)	940			940
27					-						-	-		-	-			-
28	Rounding													-	-			(1)
29	Proforma Interest (Nichols)				-						(201)	(636)		(837)	837			837
30	Interest Synchronization (Nichols)	-	-	-	-	-	-	-	-	-	0	1	-	1	(1)	-	-	(1)
31	**Total Adjustments**	-	-	-	-	-	(50,289)	(7,608)	-	-	3,395	10,768	-	(43,734)	43,734	1,923	-	45,656
32	**PFD NOI - Test Year**	3,310,110	1,385,795	90,345	4,786,249	1,385,795	1,259,482	875,900	275,525	52,234	50,172	69,295	2,134	3,970,537	815,712	34,896	(3,214)	847,393

Michigan Public Service Commission **Appendix D**
DTE Electric Company PFD
Projected Rate of Return Summary Case No.: U-20162
For Period Ending April 30, 2020

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Capital Structure				**Weighted Costs**			
Line No.	**Description**	**Amounts ($000)**	**Percent Permanent Capital**	**Percent of Total Capital**	**Cost Rate %**	**Permanent Capital**	**Total Cost %**	**Conversion Factor**	**Pre-Tax Return**
1	Long-Term Debt	6,515,850	50.00%	37.94%	4.36%	2.18%	1.65%	100.000%	1.65%
2	Preferred Stock	0	0.00%	0.00%	0.00%	0.00%	0.00%	134.964%	0.00%
3	Common Shareholders' Equity	6,515,850	50.00%	37.94%	10.00%	5.00%	3.79%	134.964%	5.12%
4	Total	13,031,699	100.00%			7.18%			
5	Short-Term Debt	112,875		0.66%	3.56%		0.02%	100.000%	0.02%
6	Investment Tax Credit (ITC) - Debt	10,433		0.06%	4.36%		0.00%	100.000%	0.00%
7	Investment Tax Credit (ITC) - Equity	10,858		0.06%	10.00%		0.01%	134.964%	0.01%
8	Total Investment Tax Credit (ITC)	21,291							
9	Deferred Income Taxes (Net)	4,006,648		23.33%	0.000%		0.00%		0.00%
10	Total	17,172,513		100.00%			5.48%		6.81%

Michigan Public Service Commission **Appendix E**
DTE Electric Company PFD
Capital Expenditure and Rate Base Adjustments Case No.: U-20162
Projected 12 Month Period Ending April 30, 2020
($000)

		(a)	(b)	(c)	(d)	(e)	(f)
			Total	**Test Year Impacts From Staff Adjustments to Cap Ex Projects**			
Line	**Witness**	**Adjustment Description**	**Cap Ex Adj.**	**Plant Adj.**	**Accum Depr.**	**Rate Base**	**Depreciation**
1	Staff	TOTAL CONTINGENCY	(10,533)	(8,217)	(120)	(8,097)	(158)
2	Staff	STEAM GENERATION - Monroe Dry Fly Ash Processing	(34,100)	(21,767)	(396)	(21,371)	(653)
3	MEC/NRDC/SC	STEAM GENERATION - River Rouge Unit 3	(1,867)	(1,167)	(20)	(1,147)	(35)
4		TOTAL STEAM GENERATION	(35,967)	(22,934)	(415)	(22,518)	(688)
5	AG & MEC/NRDC/SC	OTHER GENERATION - Ford CHP	(62,300)	(51,059)	(1,100)	(49,958)	(980)
6	Staff	DISTRIBUTION PLANT - INFRASTRUCTURE REDESIGN - Total Capital	(50,524)	(42,890)	(1,654)	(41,236)	(1,767)
7	Staff	DEMAND SIDE MGMT - Programmable Communicating Thermostats	(9,593)	(7,880)	(1,607)	(6,273)	(1,576)
8	Staff	IT - Customer Service Projects - Customer Digital Channels (MSA)	(3,195)	(1,865)	(204)	(1,661)	(373)
9	Staff	IT - Customer Service Projects - IT Business Planning	(479)	(279)	(31)	(248)	(56)
10	Staff	IT- Information Technology for IT Projects	(6,170)	(4,452)	(290)	(4,162)	(334)
11	Staff	IT - Plant and Field Projects	(3,150)	(1,846)	(227)	(1,619)	(369)
12		TOTAL IT	(12,994)	(8,442)	(751)	(7,690)	(1,132)
13	AG	CORPORATE STAFF - 2018 Underspend	(17,052)	(17,052)	(1,694)	(15,358)	(1,270)
14	Staff	CHARGING FORWARD - Total Capital	(1,744)	(872)	(18)	(854)	(36)
15		**Total Cap Ex Adjustments Impact**	(200,707)	(159,344)	(7,359)	(151,985)	(7,608)
16		Impact of Depreciation Rate Adj. on Accumulated Depreciation	Exhibit S-2, Schedule B1		-	-	
17		Working Capital Adjustments					
18		Charging Forward - Adjustment	Exhibit S-2, Schedule B4			(793)	
19		**Total Rate Base Adjustments**				(152,778)	

Source: WP-PFD-1