STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	))))))	Case No. U-20561

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 5, 2020.

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 26, 2020, 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 7, 2020.

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 OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Sharon L. Feldman

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Sharon L. Feldman
Administrative Law Judge

March 5, 2020
Lansing, Michigan

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PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On July 8, 2019, DTE Electric Company (DTE) filed a rate application requesting a $351 million revenue increase, and other relief. The rates requested in the application are based on a May 1, 2020 through April 30, 2021 projected test year. The most recent rate case orders for DTE were issued by the Commission on May 2, 2019 and July 18, 2019 in Case No. U-20162.[1] The company's application was accompanied by the testimony and exhibits of 27 witnesses.

Staff, DTE, and potential intervenors attended the July 31, 2019 prehearing conference. Intervention was granted to 23 parties: Attorney General Dana Nessel (Attorney General); Association of Businesses Advocating Tariff Equity (ABATE); Citizens

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[1] The July 18, 2019 order approved a tariff amendment for Rate Schedule D1.9, the Experimental Electric Vehicle Rate.

Utility Board (CUB); Energy Michigan, Inc.; Foundry Association of Michigan; Local 223, Utility Workers Union of America (UWUA), AFL-CIO; Great Lakes Renewable Energy Association (GLREA); Residential Customer Group (RCG); Walmart, Inc. (Walmart); The Kroger Company (Kroger); Michigan Environmental Council (MEC); The Sierra Club; Natural Resources Defense Council (NRDC); Environmental Law & Policy Center (ELPC); Ecology Center; Solar Energy Industries Association (SEIA); Vote Solar; Soulardarity; Michigan Cable Telecommunications Association; Central Transport, LLC; Central Transport, Inc.; Crown Enterprises, Inc.; Detroit International Bridge Company; and Universal Truckload Services, Inc. The parties agreed to a schedule meeting the time limits of MCL 460.6a.

DTE's application included a proposed protective order. The ALJ commented on the proposed protective order at the prehearing conference and encouraged the parties to discuss a protective order in consideration of her comments. On September 19, 2019, DTE, Staff, MEC, the Attorney General, and ABATE filed a motion for entry of revised protective order. Accompanied by a ruling, the ALJ issued a protective order on September 23, 2019 that differed from the one proposed for the reasons stated in the ruling. On September 30, 2019, DTE filed a motion for reconsideration of the protective order. After hearing oral argument on October 10, 2019, and taking the matter under advisement, the ALJ denied the motion on the record at the December 13, 2019 hearing.

Two discovery-related motions were also filed. MEC withdrew its September 24, 2019 motion to compel discovery on October 2, 2019; ABATE withdrew its October 15, 2019 motion on October 25, 2019.

By the November 6, 2019 filing deadline, Staff and the following intervenors filed direct testimony and exhibits: The Attorney General; ABATE; MEC; NRDC; Sierra Club; CUB; ELPC; the Ecology Center; Vote Solar; SEIA; Soulardarity; GLREA; RCG; Kroger; Walmart; the Foundry Association of Michigan; and UWUA Local 223. By the December 2, 2019 filing deadline, DTE, Staff, the Attorney General, ABATE, Kroger, and GLREA filed rebuttal testimony. Two motions to strike were filed on December 5, 2019, and a motion to take official notice of certain testimony in another docket was filed on December 11, 2019.

At the evidentiary hearings held on December 13 and December 16-20, 2019, twenty-two witnesses appeared for cross-examination, while the testimony of the remaining forty-six witnesses was bound into the record by agreement of the parties without the need for them to appear. The ALJ also ruled on the motions to strike and the motion for official notice. As discussed in section II below, the record includes testimony from a total of 68 witnesses, several of which were jointly sponsored by multiple parties.

The parties filed briefs and reply briefs on January 14 and February 6, 2020, in accordance the established schedule. The following parties filed briefs: DTE; Staff; the Attorney General; ABATE; MEC, NRDC, the Sierra Club, and CUB filed jointly (referred to in this PFD as the MEC Coalition); ELPC, Ecology Center, Vote Solar, and the Solar Energy Industries Association filed jointly (referred to in this PFD as the ELPC Group); Soulardarity; Energy Michigan and the Foundry Association of Michigan filed jointly; GLREA; RCG; Walmart; Kroger; and UWUA. The following parties filed reply briefs: DTE; Staff; the Attorney General; ABATE; the MEC Coalition; the ELPC Group; Soulardarity; GLREA; RCG; and Kroger.

An overview of the record is presented below.

II.

OVERVIEW OF THE RECORD

The evidentiary record in this proceeding is contained in 4017pages of transcript in 9 volumes, including confidential pages in a confidential record, and 403 exhibits admitted into evidence. The evidentiary record also includes matters officially noticed, including the testimony of Staff witness Putnam from Case No. U-17689,[2] and the reports DTE filed in Case No. U-20084.[3] As noted above, DTE requested transcript corrections by letter dated January 13, 2020. No party objected to the corrections, and this PFD finds they should be adopted with the exceptions footnoted below.[4] The discussion that follows reviews the direct testimony presented by each party, and then reviews the rebuttal testimony. This section is intended to provide a general overview; the record is discussed in further detail as necessary in the subsequent sections.

A. DTE Electric

DTE reduced its requested revenue increase from the $351 million initially filed to $343 million in its brief and then to $343.2 million in its reply brief. The utility's revised rate request is based on a jurisdictional rate base of approximately $18.3 billion, a return on

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[2] See 4Tr 110.
[3] See 6 Tr 1605.
[4] DTE asks that the word MOPS in Volume 6, page 1393, line 10 be revised, but the correct page cite for the revision is page 1392, line 10; DTE asks that "coal mine" be corrected to COLA in Volume 6, page 1597, at lines 22 and 23, but the phrase that should be corrected at that line is "coal asset"; DTE asks that the word "scattered" in Volume 6, page 1599, line 6 be corrected to "standard," but the word that should be corrected is "scatter"; DTE asks that the phrase "but it would be required" be revised to "so it would not be required" in Volume 8, page 2493, line 13, but this PFD finds instead the word "would" should be changed to "could" and no other changes should be made to that line, because this change is both a plausible mis-transcription and is consistent with the cited discovery response, Exhibit AG-1.55.

equity of 10.5% with an overall cost of capital of 5.73%, and an adjusted net operating income of $788 million. DTE presented a cost of service study and proposed pilot programs as well as rate design and tariff changes. The company is also seeking future ratemaking treatment for various categories of expenses and other accounting approvals.

DTE presented the testimony of 27 witnesses, and 43 exhibits. Many of these exhibits include multiple schedules. The review that follows begins with the testimony of the witness providing an overview of DTE's filing, followed by the testimony of witnesses primarily addressing DTE's revenue requirement, and then the testimony of witnesses addressing cost of service, rate design, and tariff issues.

Adella F. Crozier

Ms. Crozier is Director of Regulatory Affairs for DTE Energy Corporate Services LLC. Ms. Crozier's testimony, including direct, rebuttal, and cross-examination, is transcribed at 4 Tr 453-553. Her qualifications are set forth at 4 Tr 457-459. She presented an overview of the company's application, including an introduction of the other company witnesses filing testimony as part of the application, a discussion of the methods used to develop the projected test year amounts, a discussion of specific charges including the capacity charge calculation, the company's decision not to request an Infrastructure Recovery Mechanism (IRM), the tree trimming surge, the company's plans to implement time-of-use rates for residential customers, and the company's proposed low-income renewables pilot proposal.

Margaret Suchta

Ms. Suchta is employed by DTE Energy Corporate Services, LLC as a Consultant in the Regulatory Requirements group within the Regulatory Affairs organization. Ms.

Suchta's direct and rebuttal testimony is transcribed at 9 Tr 3404-3424. Her qualifications are set forth at 9 Tr 3405-3407. Ms. Suchta sponsored 2018 historical schedules in Exhibits A-1 through A-4, including the calculation of the historical revenue deficiency. For the projected test year, she presented the calculation of the projected revenue deficiency in Schedule A-1 of Exhibit A-11, as well as the projected rate base in Schedule B1 of Exhibit A-12, the projected revenue conversion factor in Schedule C2 of Exhibit A-13, and the overall weighted cost of capital in Schedule D1 of Exhibit A-14. Ms. Suchta also addressed the accounting for the Tree Trim Surge Program approved in Case No. U-20162, including the incremental revenue requirement calculated in Exhibit A-11 schedule A1.1 and the projected value of the program as shown in Exhibit A-22. Additionally, Ms. Suchta addressed the projected tax effects of interest allowed in the ratemaking formula and the interest synchronization adjustment, with schedules included in Exhibit A-13.

Theresa M. Uzenski

Ms. Uzenski is employed by DTE Energy Corporate Services, LLC as Manager of Regulatory Accounting for DTE Electric Company as well as DTE Gas Company. Ms. Uzenski's direct, rebuttal, and cross-examination testimony is transcribed at 6 Tr 1472-1619. Her qualifications are set forth at 6 Tr 1479-1481. She presented the company's historical financial schedules in Exhibits A-2 and A-3, and discussed adjustments to those schedules. For the projected test year, she presented schedules in Exhibit A-12 showing the calculation of projected utility plant and working capital, along with other financial schedules, and she presented schedules in Exhibit A-13 showing the calculation of projected net operating income along with the revenue and expense components. Ms.

Uzenski also testified in support of the company's historical and projected capital expenses and projected test year O&M expenses for its Corporate Staff Group (CSG), as shown in Schedule B5.8 of Exhibit A-12 and Schedule 5.10. Additionally, Ms. Uzenski discussed the company's accounting for the Charging Forward program and the Advanced Distribution Management System (ADMS) costs to show consistency with approvals in Case No. U-20162. She also proposed an increase in the base for the PERC (Nuclear Program) regulatory asset, and explained DTE's proposed accounting for the proposed low-income pilot programs.

Justin L. Morren

Mr. Morren is Plant Director of Fossil Generation for DTE. Mr. Morren's direct, rebuttal, and cross-examination testimony is transcribed at 5 Tr 563-751. His qualifications are set forth at 5 Tr 268-269. He testified in support of the company's historical and projected capital and O&M expenditures for the company's steam, hydro, and other non-nuclear generating units. Mr. Morren also discussed forecast changes in power plant capacity ratings, coal unit availability, planned outages and projected forced outages, the planned retirement of St. Clair unit 1, the planned conversion of River Rouge unit 3 from coal to a mixture of natural gas and recycled industrial gases, and the considerations underlying the company's plans to limit capital investment in the Tier 2 units until their retirement. Mr. Morren sponsored Exhibit A-6 as well as capital cost detail in Schedules B5.1 of Exhibit A-12 and O&M cost detail in Schedule C5.1 of Exhibit A-13.

Joyce E. Leslie

Ms. Leslie is Director – Business Planning & Development for DTE Electric. Ms. Leslie's direct, rebuttal, and cross-examination testimony is transcribed at 5 Tr 752-793.

Her qualifications are set forth at 5 Tr 756-757. Ms. Leslie presented DTE's economic analyses of the retirement of St. Clair unit 1 in 2019, the operation of River Rouge unit 3 on industrial gases until retirement in 2022, and the continued operation of the remaining St. Clair units and the Trenton Channel units. Her Net Present Value Revenue Requirement (NPVRR) analyses are included as Schedules B6.1 through B6.4 in Exhibit A-12.

Shawn D. Burgdorf

Mr. Burgdorf is Manager of the Power Supply Strategy & Modeling team within the Generation Optimization department of DTE. Mr. Burgdorf's direct, rebuttal, and cross-examination testimony is transcribed at 5 Tr 794-885. His qualifications are set forth at 5 Tr 798-800. Mr. Burgdorf presented DTE's projection of wholesale market energy sales revenue net of fuel, and to provide an overview of MISO market capacity requirements and import limitations. He also testified in support of the company's proposed tariff changes in the Emergency Electrical Procedures section, which were presented by Mr. Bloch. He presented cost and revenue information in Exhibit A-26.

David C. Milo

Mr. Milo is Fuel Resources Specialist, in the Operations and Logistics group within DTE's Fuel Supply department. Mr. Milo's direct testimony is transcribed at 9 Tr 3919-3928. His qualifications are set forth at 9 Tr 3920-3922. Mr. Milo testified in support of DTE's projected fuel supply handling costs, including capital costs as shown in Schedule B5.2 of Exhibit A-12 and O&M costs as shown in Schedule C5.2 of Exhibit A-13. The projected costs are stated separately for DTE and MERC.

Jeffrey C. Davis

Mr. Davis is Manager – Nuclear Strategy and Business Support for DTE. Mr. Davis's testimony, including his direct and rebuttal, is transcribed at 9 Tr 3427-3472, with confidential version of his rebuttal testimony in the confidential record. His qualifications are set forth at 9 Tr 3428-2429. Mr. Davis testified in support of the reasonableness and prudence of the company's historical and projected capital and O&M nuclear expenses, shown in Schedule B5.3 of Exhibit A-12 and Schedules C5.3 and C5.16 of Exhibit A-13. He also addressed the calculation of the nuclear surcharge, shown in Exhibit A-20, testifying that he followed the method approved in recent DTE rate cases, using 2018 site security and radiation protection spending updated for inflation, with no change to the other cost elements including the nuclear decommissioning and low level radioactive waste disposal funding.

Marco A. Bruzzano

Mr. Bruzzano is Vice President of Distribution Operations for DTE Energy Corporate Services, LLC. Mr. Bruzzano's testimony, including his direct, rebuttal, and cross-examination, is transcribed at 4 Tr 113-384. His qualifications are set forth at 4 Tr 117-120. He testified to support the reasonableness and prudence of the company's historical and projected distribution system capital expenditures and projected O&M expenses. He presented summary schedules within Exhibits A-12 and A-13, as well as Exhibit A-23.

Mr. Bruzzano's direct testimony provided an overview of the company's distribution system and performance metrics, a comparison of actual capital expenditures to forecast expenditures in the last rate case, a discussion of the company's distribution system plans and planning process, and additional details regarding its capital and O&M expense projections.

Jacqueline L. Robinson

Ms. Robinson is Director of Operational Technology in DTE's Electric Distribution Operations department. Ms. Robinson's testimony, including her direct, rebuttal, and cross-examination, is transcribed at 9 Tr 2606-2655. Her qualifications are set forth at 9 Tr 2610-2612. She presented an update on DTE's AMI meter installations, and testified in support of DTE's historic and projected capital spending for its AMI project. She also addressed DTE's AMI meter opt-out program, including its ongoing installation of digital meters to comply with the Commission's order in Case No. U-20084. Projected capital expenditures are in her Schedule B5.4 of Exhibit A-12 with additional detail in her Schedule M6 of Exhibit A-23. She presented DTE's analysis of AMI benefits in Exhibit A-19.

Robert A. Bellini

Mr. Bellini is Manager of Community Lighting for DTE. Mr. Bellini's testimony is transcribed at 9 Tr 3475-3505. His qualifications are set forth at 9 Tr 3476-3477. Mr. Bellini addressed DTE's lighting program, testifying in support of the company's projected capital and O&M costs, as shown in Schedule B5.5 of Exhibit A-12 and Schedule C5.6 of Exhibit A-13. He also presented the energy sales forecast for each of the outdoor lighting rates as reflected in Schedule F3 of Exhibit A-16, as well as the company's proposed rate design for the residential and commercial outdoor protective lighting and municipal lighting tariffs as reflected in Schedule F8 of Exhibit A-16. He testified that the rate design follows the same method as in the company's last rate case. He also discussed DTE's outage restoration performance, with statistics presented in Exhibit A-25.

Rodrigo Cejas Goyanes

Mr. Cejas Goyanes is a Strategy and Project Specialist in the Demand Response (DR) and Energy Waste Reduction (EWR) Strategy department of DTE. Mr. Cejas Goyanes's direct and rebuttal testimony is transcribed at 9 Tr 3507-3557. His qualifications are set forth at 9 Tr 3508-3510. He testified in support of DTE's DR activities and proposed expenditures, sponsoring Schedule B5.6 of Exhibit A-12 showing the projected capital expenditures, and Exhibit A-30, with details regarding the company's DR programs. After describing the company's DR portfolio, he specifically discussed ongoing and planned improvements to the company's interruptible air conditioning (IAC) program, ongoing and planned pilot programs, and the DTE Insight program, which provides customers with real-time information to help manage their energy consumption.

Heather C. Rivard

Ms. Rivard is Senior Vice President of Distribution Operations for DTE Energy Corporate Services, LLC. Ms. Rivard's testimony, including her direct and rebuttal, is transcribed at 9 Tr 3577-3636. Her qualifications are set forth at 9 Tr 3578-3580. Ms. Rivard testified in support of DTE's tree trimming program and the projected expenses, including the Surge Program approved in Case No. U-20162 and recent and planned improvements. Her Schedule C5.6.1 of Exhibit A-13 shows projected expense for tree trimming, while her Exhibit A-22 presents her estimate of the net present value of the Surge Program.

Daniel J. Griffin

Mr. Griffin was Director – Information Officer within the IT Services organization of DTE Energy Corporate Services, LLC at the time he filed his testimony; his position changed subsequently to Director of Distribution Operations for DTE.[5] Mr. Griffin's direct, rebuttal, and cross-examination testimony is transcribed at 8 Tr 2351-2341. His qualifications are set forth at 8 Tr 2355-2356. Mr. Griffin testified to support the company's historical and projected Information Technology (IT) capital expenditures, providing an overview of the IT department, DTE's IT capital expense categorizations, and planning process. He sponsored Schedules B5.7 through B5.7.8 in Exhibit A-12, as well as executive summaries of the business cases for the major projects and a comparison of approved to actual capital spending for 2018 in his Exhibit A-24.

Eric W. Clinton

Mr. Clinton is a Manager in DTE's Electric Regulated Marketing Organization. Mr. Clinton's testimony, including his direct, rebuttal, and cross-examination, is transcribed at 6 Tr 993-1132. His qualifications are set forth at 6 Tr 998-1000. Mr. Clinton presented testimony explaining DTE's approved electric vehicle (EV) program, "Charging Forward," and projected capital costs. He also testified in support of the company's projected increase in merchant fees (credit card expenses), and Electric Regulated Marketing O&M Expenses. Mr. Clinton also presented testimony to support two proposed pilot programs, the Fixed Bill Pilot and the Low Income Renewables Pilot. He presented summary cost

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[5] See 8 Tr 2484.

information in Schedule B5.9 of Exhibit A-12 and Schedules C5.7.1 and C5.9 of Exhibit A-13, with additional supporting information in his Exhibits A-27 through A-29.

Michael S. Cooper

Mr. Cooper is Director of Compensation, Benefits & Wellness for DTE Energy Corporate Services LLC. Mr. Cooper's direct, rebuttal, and cross-examination testimony is transcribed at 5 Tr 886-977. His qualifications are set forth at 5 Tr 890-891. Mr. Cooper testified in support of the company's projected employee compensation expenses for the test year, including pension and other post-employment benefit costs (OPEB), active employee health care costs, and other benefit costs. He testified in support of the company's request to recover the costs of employee incentive programs, and its proposed labor cost escalation assumptions used to develop the company's composite inflation factors. Mr. Cooper sponsored supporting cost schedules within Exhibit A-13, as well as employee compensation information in Exhibit A-21.

Tamara D. Johnson

Ms. Johnson is Director of Revenue Management and Protection for DTE Energy Corporate Services LLC. Ms. Johnson's direct, rebuttal, and cross-examination testimony is transcribed at 6 Tr 1133-1196. Her qualifications are set forth at 6 Tr 1136-1137. She testified in support of DTE's projected uncollectible accounts expense, as shown in Schedule C5.8 of Exhibit A-13, and she also explained DTE efforts to reduce uncollectible expense. She also explained DTE's Low Income Self Sufficiency Program, and identified changes DTE is proposing to its rate book to expand eligibility for the Residential Income Assistance provision and increase funding for the Residential Service Special Low-Income Pilot tariff.

Sherri L. Wisniewski

Ms. Wisniewski is Director of Tax Operations for DTE Energy Corporate Services, LLC. Ms. Wisniewski's testimony is transcribed at 9 Tr 3559-3575. Her qualifications are set forth at 9 Tr 3560-3561. She testified in support of DTE's projected federal, state, and municipal income tax expense, property tax expense, and other general taxes. She testified that DTE's treatment of the 2017 federal Tax Cuts and Jobs Act (TCJA) was consistent with prior Commission orders, including the company's Calculation C case, Case No. U-20162. She sponsored the historical 2018 tax expenses schedules in Exhibit A-3, and the projected tax expense schedules in Exhibit A-13.

Henry N. Campbell

Mr. Campbell is Director of the Customer Care Organization within DTE Energy Corporate Services, LLC. Mr. Campbell's direct and cross-examination testimony is transcribed at 8 Tr 2542-2577. His qualifications are presented at 8 Tr 2545-2546. He testified in support of the company's projected $94 million O&M expense for the Customer Service group. He presented Schedule C5.7 of Exhibit A-13, showing a breakdown of the O&M expense projection for this group, in support of his testimony. Mr. Campbell also explained DTE's plans to implement shadow billing consistent with the Commission's order in Case No. U-20162.

Marcus B. Leuker

Mr. Leuker is Manager of Corporate Energy Forecasting for DTE. Mr. Leuker's testimony, including his direct, rebuttal, and cross-examination, is transcribed at 4 Tr 393-452. Mr. Leuker explained and presented the company's projected test year sales forecast. His qualifications are set forth at 4 Tr 398-400. He discussed economic considerations underlying the forecast, and described the development of sales, maximum demand, and system output values. He sponsored both the historical sales and system output schedule in Exhibit A-5, and the projected values with supporting information in Exhibit A-15.

Edward J. Solomon

Mr. Solomon is Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy Company (DTE Energy) and its subsidiaries including DTE. Mr. Solomon's direct and rebuttal testimony is transcribed at 6 Tr 1447-1468. His qualifications are set forth at 6 Tr 1448-1450. He presented DTE's proposed capital structure, 50% debt and 50% equity on a permanent basis, along with supporting testimony, and also testified to the projected costs of short-term and long-term debt. His Schedule A2 in Exhibit A-1 and Schedules D2, D3, D4 and D5 in Exhibit A-4 contain historical financial metrics and cost data, while the comparable schedules showing projected costs and financial metrics are included in Exhibit A-14. Mr. Solomon's Exhibit A-18 also contains information regarding DTE credit ratings and recent bond issuances.

Dr. Bente Villadsen

Dr. Villadsen is a Principal in the consulting firm The Brattle Group. Her qualifications are set forth at 6 Tr 1204-1205 and 1271-1287. Dr. Villadsen's direct, rebuttal, and cross-examination testimony is transcribed at 6 Tr 1197-1393. She presented testimony recommending an authorized return on equity of 10.5% for DTE, based on a range of 9.75% to 10.75%. She presented supporting schedules in Exhibit A-14.

Thomas W. Lacey

Mr. Lacey is a Principal Financial Analyst in the Revenue Requirements Department of the Regulatory Affairs Organization of DTE Energy Corporate Services, LLC. Mr. Lacey's direct, rebuttal, and cross-examination testimony is transcribed at 7 Tr 2005-2114. His qualifications are set forth at 7 Tr 2010-2012. He presented DTE's cost of service studies for the projected test year, and testified in support of the company's revenue requirement calculations for customer-related costs and for the capacity charge by rate class. Mr. Lacey's cost of service study is contained in Schedule F1.1 of Exhibit A-16, with the allocations by voltage level shown in Schedule F1.2, a functionalization overview in Schedule F1.3, customer charges presented in Schedule F1.4 and capacity charges by rate class in Schedule F1.5 of that exhibit.

Alex M. Brasil

Mr. Brasil is a Senior Rates Analyst – Load Research for DTE Energy Services, LLC. Mr. Brasil's direct, rebuttal, and cross-examination testimony is transcribed at 8 Tr 2314-2349. His qualifications are set forth at 8 Tr 2318-2319. He testified to support DTE's forecast allocation schedules in Exhibit A-17, used in DTE's cost of service study. He presented a diagram of the allocation methods and a description of the allocation schedules in Schedules E2 and E3 of Exhibit A-5. Mr. Brasil testified that the allocation schedules reflect the sales forecasts sponsored by Mr. Leuker, and are consistent with the Commission's decisions in recent rate cases. He also explained the treatment of the electric choice customer demand.

Philip W. Dennis

Mr. Dennis is Manager for Regulatory Economics with DTE Energy Corporate Services, LLC. Mr. Dennis's direct, rebuttal, and cross-examination testimony is transcribed at 7 Tr 2114-2142. His qualifications are set forth at 7 Tr 2118-2120. Mr. Dennis presented DTE's proposed residential rate design and tariff changes. He testified that his recommended capacity and non-capacity charges were based on the cost of service supported by Mr. Lacey. He also explained the company's proposed cap on variable distribution rates for residential secondary rate schedules, tariff language to expand the Residential Income Assistance program consistent with Ms. Johnson's testimony and to implement the proposed Fixed Bill pilot program consistent with Mr. Clinton's testimony, and the calculation of outflow credits for the company's distributed generation Rider 18. Mr. Dennis presented schedules in support of his testimony contained in Exhibit A-16, including present and proposed revenue by rate schedule for the residential rate schedules in Schedule F3, a comparison of present and proposed monthly bills in Schedule F4, the calculation of the Rider 18 outflow credits in Schedule F7, and tariff revisions in Schedule F8.

Kelly A. Holmes

Ms. Holmes is a Principal Financial Analyst for Regulatory Economics at DTE Energy Corporate Services, LLC. Ms. Holmes's testimony, including her direct, rebuttal, and cross-examination, is transcribed at 8 Tr 2242-2273. Her qualifications are set forth at 8 Tr 2246-2249. Ms. Holmes presented DTE's proposed rate design for commercial secondary rate schedules based on Mr. Lacey's cost of service study, testifying that she used the same methods approved in DTE's most recent rate cases. Her proposed rate design is reflected in Schedules F3, F4 and F8 of Exhibit A-16. Ms. Holmes also presented a calculation of DTE's total power supply costs for the projected test period, included in Schedules C4 and C5.14 of Exhibit A-13. She recommended that the Commission retain the current generation-level base PSCR factor of 31.26 mills per kilowatthour (kwh), but increase the loss factor to 7.3%, resulting in a sales-level base PSCR factor of 33.54 mills per kwh.

Timothy A. Bloch

Mr. Bloch is a Principal Financial Analyst within the Regulatory Affairs department of DTE Energy Corporate Services, LLC. Mr. Bloch's direct, rebuttal, and cross-examination testimony is transcribed at 8 Tr 2274-2312. His qualifications are set forth at 8 Tr 2278-2281. He presented the company's primary rate design, as well as proposed tariff changes for the interruptible service rate schedules (Rates D3.3 and D8 and Riders R1.1, R1.2, and R10). Mr. Bloch based his rate design on the cost of service study sponsored by Mr. Lacey. He testified that monthly service charges by voltage level were determined using Staff's method as approved in Case No. U-20162. For the interruptible schedules, Mr. Bloch testified that DTE is attempting to make the language more consistent across tariffs, and is proposing a non-interruption penalty. He also identified a revised Rate D3.3 offering, priced at the D3 rate, with a one-year contract term to reflect MISO capacity registration requirements.

Mr. Bloch also presented the company's proposed nuclear surcharge. His primary class rate design is reflected in Schedules F2, F3, F4 and F5 of Exhibit A-16, with the nuclear surcharge calculation shown in Schedule F6 of that exhibit. Tariff sheets reflecting the proposed rate design and interruptible service changes are in Schedule F8 of Exhibit A-16.

B. **Staff**

Staff's filing recommended a revenue deficiency of approximately $195 million based on a projected test year rate base of $18.120 billion, a return on equity of 9.8%, and adjusted net operating income of $840.3 million as shown in Exhibit S-1 Schedule A1. Staff also presented a cost of service study and rate design recommendations. Staff's briefs recommend additional adjustments to the revenue deficiency calculation, with the resulting revenue deficiency stated in Staff's reply brief as $195.8 million, with a recommended rate base of $18.128 billion, and adjusted net operating income of $839.9 million.[6] Eighteen Staff members testified, with two Staff witnesses presented only rebuttal testimony; Staff also presented 51 exhibits, which include multiple schedules with decimal numbering. As with the review of the testimony of DTE witnesses above, this review begins with the testimony of witnesses primarily addressing revenue requirements, followed by the testimony of witnesses primarily addressing cost of service, rate design, and other issues.

Robert F. Nichols II

Mr. Nichols is Manager of the Revenue Requirements Section of the Financial Analysis and Audit Division of the MPSC. Mr. Nichols's testimony is transcribed at 9 Tr 3325-3333. His qualifications are set forth at 9 Tr 3326-3329. Mr. Nichols presented the calculation of Staff's projected revenue deficiency of $194.9 million in Exhibit S-1

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[6] See Staff reply brief, Appendix A.

(Schedule A1), and the calculation of Staff's projected net operating income at current rates in Exhibit S-3 (Schedule C1), incorporating recommendations presented in testimony from several other Staff witnesses. Addressing the TCJA of 2017, Mr. Nichols recommended that DTE be required to meet the same reporting requirements as other utilities to account for excess deferred tax balances, through an annual letter to be filed in this docket.

Michelle L. Edelyn

Ms. Edelyn is an auditor in the Revenue Requirements section of the MPSC's Regulated Energy Division. Ms. Edelyn's testimony is transcribed at 9 Tr 3207-3213. Her qualifications are set forth at 9 Tr 3208-3209. She presented Staff's projected test year rate base of $18,119,965,000, shown in Schedule B1 of Exhibit S-2. Figure 1 at 9 Tr 3211 summarizes the adjustments to DTE's capital expense projections supported by other Staff witnesses. Ms. Edelyn also explained corresponding adjustments to depreciation reserve and the projected depreciation and amortization expense. She also incorporated Staff's recommended adjustment to working capital, sponsored by Mr. Witt and Mr. Gerken, in the rate base calculation.

Timothy G. Witt

Mr. Witt is an auditor in the Revenue Requirements section of the MPSC's Regulated Energy division. Mr. Witt's testimony is transcribed at 9 Tr 3214-3217. His qualifications are set forth at 9 Tr 3215. Mr. Witt presented Staff's projected working capital, shown in Schedule B4 of Exhibit S-2. He testified that Staff reduced DTE's projected working capital to correct a $2 million error in the company's Accounts Payable – Associated Companies balance, as shown in Exhibit S-10.0, and to reflect a $88.3

million adjustment to Other Accounts Receivable – Associated Companies supported by Staff witness Gerken.

Jay S. Gerken

Mr. Gerken is Manager of the Rate Base Unit in the Revenue Requirements section of the MPSC's Regulated Energy Division. Mr. Gerken's testimony is transcribed at 9 Tr 3235-3241. His qualifications are set forth at 9 Tr 3236-3238. Mr. Gerken testified in support of a recommended adjustment to the working capital allowance to remove the Other Accounts Receivable-Assoc. Co. balance. Citing a Staff audit request in Exhibit S-9.0, Mr. Gerken testified that $68,020,626 in this account balance is attributable to amounts due from REF companies, although DTE's contract with those companies ended in 2018. Citing Exhibit S-9.1, Mr. Gerken testified that the remaining balance of $20,271,408 in this account relates to non-utility services.

Jonathan J. DeCooman

Mr. DeCooman is Public Utilities Engineer in the Generation and Certificate of Need section of the MPSC's Energy Resources division. Mr. DeCooman's testimony is transcribed at 9 Tr 3198-3196. His qualifications are set forth at 9 Tr 3199-3201. Mr. DeCooman recommended that contingency expenses totaling approximately $17.4 million be removed from DTE's capital expense projections, citing prior Commission decisions. His Exhibit S-15.0 provides a breakdown of the contingency amounts included in the company's projections.

Jing Shi

Ms. Shi is a Public Utilities Engineer in the Act 304 and Sales Forecasting section of the Commission's Energy Operations division. Ms. Shi's testimony is transcribed at 9

Tr 3343-3351. Her qualifications are set forth at 9 Tr 3344-3346. She addressed DTE's projected production plant O&M expenses including the fuel supply and MERC fuel handling, recommending a reduction of $5.5 million to reflect Staff's inflation estimates as shown in Exhibits S-7.3 and S-7.4. She also addressed DTE's proposed loss factor. While agreeing with Ms. Holmes's definition in principle, she objected to DTE's use of 7.3% without an updated line loss study. She recommended instead that the Commission use a loss factor based on historical sales and net system output. As shown in Exhibit S-7.0, she calculated a loss factor of 7.23% based on a five-year average of historical data taken from Schedule E2 of Exhibit A-15 and Exhibit S-7.1, and recommends that this be used in the calculation of power supply expense, as shown in Exhibit S-7.2.

Nicholas M. Evans

Mr. Evans is a Public Utilities Engineering Specialist in the Electric Operations section of the MPSC's Energy Operations division. Mr. Evans's testimony is transcribed at 9 Tr 3219-3233. His qualifications are set forth at 9 Tr 3220-3223. Mr. Evans presented Staff's review of DTE's projected distribution capital and O&M expenses. He testified that Staff does not recommend adjustment to DTE's distribution system capital spending, with the exception of an AMI-related adjustment discussed by Staff witness Wang. He testified that DTE spent $22 million more in 2018 than it initially projected for 2018 and $41 million more than the Commission ultimately approved in Case No. U-20162. He agreed with Mr. Bruzzano's conclusion that the additional spending was driven by weather. He testified that Staff also does not recommend any adjustment to DTE's proposed distribution system O&M spending, including its proposed additional spending for the Surge program of $58.2 million for 2022. He recommended that DTE be required to discuss in its annual report on the Surge program the progress it is making toward achieving an adequate level of qualified local tree trimmers.

<u>Joy H. Wang</u>

Dr. Wang is a Public Utilities Engineer in the Smart Grid section of the MPSC's Energy Resources division. Dr. Wang's testimony is transcribed at 9 Tr 3353-3379. Her qualifications are set forth at 9 Tr 3354-3356. She presented Staff's recommendations regarding DTE's AMI-related reporting, and proposed expenditures for AMI communications upgrades. She testified that DTE did not comply with the Commission's directive in Case No. U-18255 that it continue to report on AMI benefits, objecting that DTE did not present historical benefit information and did not present actual benefit analysis but only projected benefits. She also disagreed with Ms. Robinson's assertion that most of the initial benefits of AMI have been realized. She recommended that DTE be required to meet its reporting obligation in future cases, explaining revisions to the analysis DTE presented in this case. She also recommended that the Commission disallow DTE's projected $2 million "optimization phase" expenditure to install additional cell relays, and its proposed expenditure to install power quality meters at approximately 950 industrial customer cites as part of its 3G to 4G communications upgrade.

Dr. Wang also addressed DTE's projected IT spending. Under the "emergent" heading, she cited great uncertainty in the projects in terms of scope, benefits, and costs, in recommending the disallowance of all 2019 "emergent" program funds not yet expended, approximately $3.1 million. Under "applied innovation," and "digital engagement group," she expressed similar concerns and recommended that the projected expenditures be disallowed. Addressing the proposed bill redesign expenditures, she recommended a disallowance based on the total $10.12 million cost of the redesign over a three-year period, and the general absence of complaints. Turning to the projected spending to enhance the AMI mesh read rate, Dr. Wang acknowledged that spending had been approved in a prior rate case, but recommended that all additional spending be disallowed. Finally, addressing DTE's EV pilot, she recommended reporting requirements and provided additional recommendations regarding DTE's study of the pilot results. She also recommended that DTE include a low-income component for the residential rebate, and to develop a more equitable education and outreach. She presented Exhibits S-12.1 through S-12.16 in support of her testimony.

Brian Welke

Mr. Welke is the Manager of the Income Analysis unit in the MPSC's Regulated Energy division. Mr. Welke's testimony is transcribed at 9 Tr 3334-3341. His qualifications are set forth at 9 Tr 3335-3336. Mr. Welke presented Staff's recommended test year O&M expense allowance of $1,297,076,000, as shown in Schedule C5 of Exhibit S-3. He also addressed DTE's EV program, recommending that the test year amortization amount be reduced to reflect full recovery of the deferred costs by January 20, 2021. Mr. Welke recommended a reduction in the Charging Forward program expenses, for which the Commission authorized regulatory asset accounting and amortization, to reflect actual expenditures. He also recommended that projected 2020 spending not be included in rates until the spending could be reviewed. He testified that his adjustments to the Charging Forward program costs are not reflected in Staff's revenue requirement calculations.

Theresa McMillan-Sepkoski

Ms. McMillan-Sepkoski is an Audit Specialist in the Revenue Requirements Section of the MPSC's Regulated Energy Division. Ms. McMillan-Sepkoski's testimony is transcribed at 9 Tr 3271-3284. Her qualifications are set forth at 9 Tr 3272-3274. She presented Staff's recommended adjustments to DTE's projected employee compensation expenses, uncollectible accounts expense, and injuries and damages expense. She also addressed DTE's projected merchant fee expense and proposal to limit the customer groups eligible for free credit card payments, recommending that the free credit payment option be limited to residential customers. She also took issue with the study DTE presented in response to the Commission's order in Case No. U-20162. She presented Exhibits S-8 through S-8.10.

Kurt D. Megginson

Mr. Megginson is a Financial Specialist in the Revenue Requirements Section of the Commission's Financial Analysis and Audit Division. Mr. Megginson's testimony is transcribed at 9 Tr 3286-3269. His qualifications are set forth at 9 Tr 3287-32889. Mr. Megginson presented Staff's analysis of the appropriate return on equity, recommending that the Commission authorize a return on equity of 9.80%, based on range of 8.90% to 9.90%. In determining the cost of equity capital, Mr. Megginson performed several analyses of the cost of capital for a proxy group of companies including a discounted cash flow study, a Capital Assets Pricing Model study, and a risk premium analysis. The results of these analysis are presented in his Schedule D5 of Exhibit S-4. He also considered other recent state commission return on equity awards and the company's currently-authorized rate of return.

Joseph E. Ufolla

Mr. Ufolla is a financial analyst in the Revenue Requirements section of the MPSC's Regulated Energy Division. Mr. Ufolla's testimony is transcribed at 9 Tr 3314-3322. His qualifications are set forth at 9 Tr 3315-3316. Mr. Ufolla presented the calculation of Staff's overall cost of capital, including testimony addressing the capital structure balances and debt-cost rates. He explained that Staff adopted DTE's proposed capital structure balances, and updated the cost of long-term debt and short-term debt to reflect more recent forecasts. His overall cost of capital also incorporated Staff's recommended return on equity as presented by Mr. Megginson. Mr. Ufolla also presented Staff's projected inflation rates for 2019-2021. His cost of capital and inflation recommendations are shown in schedules in Exhibit S-4, with additional supporting information in Exhibit S-14.

Daniel J. Gottschalk

Mr. Gottschalk is a departmental specialist and the Electric Cost of Service Specialist in the Rates and Tariff Section of the MPSC's Regulated Energy division. Mr. Gottschalk's testimony, including direct and rebuttal, is transcribed at 9 Tr 3243-3260. His qualifications are presented at 9 Tr 3244-3246. He presented Staff's class cost of service study, Schedules F1.1 and F1.2 of Exhibit S-6. He testified that Staff used the methods approved in Case No. U-20162, and thus made two changes to the methods used in DTE's cost of service study, a revision to the treatment of property taxes associated with meters and services, and a revision to the line loss factors and affected allocators. Mr. Gottschalk further addressed Staff's recommended customer charge and Staff's calculation of the capacity cost revenue requirement, shown in Schedules F1.4

and F1.5 of Exhibit S-6. Citing his Exhibit S-16, Mr. Gottshalk testified that Staff used the line loss factors approved in Case No. U-20162 in lieu of the factors DTE used, taken from a 1995 loss study. He recommended that the company be directed to conduct a new line loss study before its next electric case.

David W. Isakson

Mr. Isakson, a Departmental Analyst in the Rates and Tariffs Section of the MPSC's Regulated Energy Division, presented Staff's recommendations regarding DTE's rate design, present revenue, tariffs, pricing pilots, and DR programs. Mr. Isakson's testimony, including his direct, rebuttal, and cross-examination, is transcribed at 9 Tr 3107-3186. His qualifications are set forth at 9 Tr 3111-3112. Mr. Isakson explained that Staff increased present revenue by $1.6 million to reflect projected rather than historical fees from the energy bridge program, and by $10.7 million to reflect revised customer counts based on a five-year average for the RIA and LIA programs. Mr. Isakson also incorporated an adjustment to PSCR revenue to match the PSCR base expense presented by Ms. Shi.

In determining voltage-level discounts for primary rates, he testified that Staff relied on the Commission-approved method rather than maintaining the same proportion between charges as in current rates, as DTE did. He testified that Staff used demand and energy line loss factors approved in the company's last rate case, but noted Staff witness Gottschalk's recommendation that the Commission require DTE to conduct a line loss study that could be used to determine voltage-level discounts in future cases.

Mr. Isakson also recommended that the Commission adopt in this case Staff's proposed summer on-peak residential tariff, which relies on the relative difference in

Locational Marginal Prices (LMPs) between summer on-peak and other hours to determine the on-peak and off-peak rates, to be effective by summer 2021. He also proposed that this tariff have an opt-out structure.

Mr. Isakson recommended against approving capital expenditures for DTE's Advanced Customer Pricing Pilot, pending review in Case No. U-20602. He supported DTE's proposed shadow billing plan, but objected to DTE's proposed fixed bill pilot. He also recommended that the Commission set the effective date for rates 7 calendar days from the date its order is issued to allow time for the company to reconfigure its billing system with the new rates.

The calculation of Staff's proposed revenue in Schedule C3 in Exhibit S-6, while Staff's present and proposed revenue by rate schedule, typical bill comparisons, and calculation of voltage level distribution charges, are in Schedules F2 through F5 of that exhibit. Staff's calculation of power supply transmission rates is shown in Schedule F7 of that exhibit.

<u>Brad B. Banks</u>

Mr. Banks is a Departmental Analyst in the Energy Waste Reduction Section of the MPSC's Energy Resources Division. Mr. Banks's testimony is transcribed at 9 Tr 3189-3196. His qualifications are set forth at 9 Tr 3190-3192. He presented Staff's recommendation that DTE's low-income renewables pilot should not be approved, contending it should be redesigned to be more beneficial to low-income customers. He recommended that DTE work with the MPSC's renewable energy (RE) and energy waste reduction (EWR) sections to design a better program, and provided examples of existing programs with direct benefits to low-income participants.

Cody S. Matthews

Mr. Matthews is Public Utilities Engineer Specialist in the Renewable Energy section of the MPSC's Energy Resources division. Mr. Matthews's testimony is transcribed at 9 Tr 3262-3269. His qualifications are set forth at 9 Tr 3263-3264. He presented Staff's recommendations regarding the minimum program size for the net metering and distributed generation programs under Act 295. Reviewing DTE's current program size and participation, including the information in Exhibits S-13.0 and S-13.1, he presented a forecast showing DTE would reach its statutory "soft caps" between 2021 and 2023. He recommended that DTE continue to accept applications through the pendency of its next rate case, even if it reaches the cap in that time period.

C. Attorney General

This section reviews the testimony of two witnesses sponsored by the Attorney General; as discussed below, the Attorney General also jointly sponsored a witness with the MEC Coalition.

Sebastian Coppola

Mr. Coppola is an independent consultant. Mr. Coppola's testimony, including his direct and rebuttal, is transcribed at 9 Tr 2954-3105. His qualifications are set forth at 9 Tr 2956-2959 and 3079-3096. Mr. Coppola provided an analysis of DTE's revenue requirement, recommending revisions to the company's projected ratebase, including projected capital expenditures and working capital, to the proposed return on equity and capital structure balances, and to adjusted net operating income including projected sales and O&M expenses. He presented Exhibits AG-1.1 through AG-1.42 in support of his testimony. The capital expenditure reductions he proposes are summarized in a table at

9 Tr 3007; his adjustments to working capital are shown in Exhibit AG-1.15; the overall cost of capital based on his ratemaking capital structure and proposed return on equity of 9.25% is computed in Exhibit AG-1.16; the billing determinants resulting from his recommended adjustments to the residential and commercial sales volumes are shown in Exhibit AG-1.29; his recommended adjustments to O&M expenses are summarized in a chart at 9 Tr 3074 and in Exhibit AG-1.41. Mr. Coppola identified an overall revenue deficiency of $41.1 million for the projected test year, with the calculations summarized in Exhibit AG-1.42. Accompanying his recommendation that funding for DTE's proposed fixed-bill pilot be excluded, Mr. Coppola also explained his objections to the proposed pilot.

<u>David E. Dismukes</u>

Professor Dismukes is a Consulting Economist with the Acadian Consulting Group and he is a Professor, the Executive Director, and the Director of Policy Analysis at the Center for Energy Studies, Louisiana State University. Professor Dismukes's direct and rebuttal testimony is transcribed at 9 Tr 2829-2825. His qualifications are set forth at 9 Tr 2831-2832 and 2874-2937. Professor Dismukes addressed DTE's class cost of service study and revenue distribution. He recommended that the Commission adopt a 4CP 50-0-50 cost allocation method for allocating production costs, a 12CP 100-0-0 method for allocating subtransmission plant facilities, and a non-coincident peak (NCP) method for allocating secondary-distribution plant facilities, with corresponding changes in the revenue distribution. In extensive testimony explaining his objections to the present allocation methods for these plant categories, he presented Exhibits AG-2.1 through AG-2.12 in support of his recommendations, with a comparison of the resulting class revenue requirements to DTE's methods, at both current and proposed rate levels in exhibit AG-2.12. As an alternative, should the Commission reject this recommendation, he proposed that the Commission limit residential customer rate increases to 1.15 times the overall system average increase, or 8.2% using DTE's proposed revenue increase.

D. <u>Attorney General and MEC Coalition (MEC, NRDC, Sierra Club, and CUB) Roger D. Colton</u>

Mr. Colton is a consultant and a principal in the firm of Fisher Sheehan & Colton, Public Finance and General Economics. Mr. Colton's testimony is transcribed at 9 Tr 363-3733. His qualifications are set forth at 9 Tr 3641-3644 and in Exhibit MEC-1. He recommended modifications to DTE's low-income assistance programs, with recommendations targeted to all low-income customers, to customers facing extreme poverty, and to customers who fall just above the income eligibility ceiling for existing programs. His testimony and the exhibits he sponsored, Exhibits MEC-2 through MEC-31, provide information on the affordability of DTE's bills from multiple perspectives, incorporating available data and discussing experiences in other states. He concluded that average DTE bills frequently or generally are unaffordable for low-income households, and that providing adequate bill assistance to low-income customers will help improve payment outcomes for DTE. He recommended that DTE's Low-Income Assistance program be expanded to automatically enroll food stamp recipients, that the credit be increased from $40 per month to $60 per month, and that an additional $25 monthly credit go to customers in extreme poverty, with incomes below 50% of the federal poverty level. Mr. Colton also recommended that Residential Income Assistance Credits be directed toward households establishing special needs, including customers who qualify for seasonal protections, with incomes up to 200% of the federal poverty level.

E. MEC Coalition

Steve Letendre

Dr. Letendre is a consultant with Synapse Energy Economics. Dr. Letendre's testimony is transcribed at 9 Tr 3736-3793, with a confidential version in the confidential record. His qualifications are set forth at 9 Tr 3740-3741 and in Exhibit MEC-32. He evaluated the economics of operating River Rouge unit 3 on industrial gasses through 2022 versus the prior plan to retire the unit in 2020. After concluding that the economics do not justify continued operation, he recommended that the Commission continue to disallow rate recovery for the capital expenditures previously disallowed, and disallow further capital and O&M expenses inconsistent with a May 2020 retirement. As part of his analysis, Dr. Letendre also looked at DTE's reliance on the PACE capacity price forecast, in light of recent changes to the Zone 7 Capacity Import Limits and other information. He concluded that DTE's PACE modeling incorrectly incorporated the Capacity Import Limit, and that the underlying model is out of date and should not be relied on.

Dr. Letendre also addressed the economics of DTE's projected capital investments in Belle River, in light of the Commission's prior findings that a 2025-2026 retirement is more economic for ratepayers. He recommended the Commission require DTE to present a thorough plan for capital and major maintenance spending under both a 2025-2026 and a 2029-2030 retirement scenario. Lastly, he addressed DTE's collection of funds for the closure of facilities storing coal combustion residuals, recommending that DTE provide a full accounting of current and future costs in its next rate case filing.

Douglas B. Jester

Mr. Jester is a Partner of the firm 5 Lakes Energy LLC. Mr. Jester's testimony is transcribed at 9 Tr 3795-3860. His qualifications are set forth at 9 Tr 3796-3799 and in Exhibit MEC-58. Mr. Jester objected to DTE's reliance on a 1995 line loss study, testifying to the importance of accuracy and the factors that could change the loss factors over the intervening years. He recommended that the Commission reject the recommendation of DTE witness Holmes to increase the loss factor used to calculate the PSCR base, and direct DTE to prepare and file a new engineering loss study before its next rate case. Addressing distribution system reliability, Mr. Jester recommended that the Commission consider performance-based ratemaking measures to improve DTE's distribution system performance, for adoption in DTE's next rate case. Noting the magnitude of DTE's historical and projected spending for new customer connections, Mr. Jester also recommended that the Commission revise the Contribution in Aid of Construction (CAIC) policy, to limit DTE's contribution to 4.5 times the estimated annual distribution revenue from a customer.

Addressing the cost of service allocations, Mr. Jester recommended that the Commission treat distributed generation (DG) customer outflows as offsetting inflows for each customer class in future cases. Turning to production cost allocation, Mr. Jester explained the equivalent peaker and probability of dispatch methods of allocation, and the analysis he undertook in conjunction with MEC Coalition witnesses Boothman, Bunch, and Gard. He presented the results in Exhibit MEC-66, and explained the changes in class cost responsibility resulting from the use of these methods. He recommended that the Commission consider these results, and also that it direct DTE to provide a revenue requirement by generation resource in its next rate case.

Addressing rate design, Mr. Jester took issue with DTE's proposed fixed bill pilot, urging the Commission to reject the proposal on the same grounds it rejected the company's similar proposal in Case No. U-20162. He also noted DTE's ex parte application in Case No. U-20602 to address the company's transition to time-of-use rates, identifying deficiencies in the company's application. Mr. Jester commented favorably on DTE's EV program, further recommending that the EV-Ready Builder program be expanded to include multi-family dwellings. Mr. Jester also addressed the DG tariff, identifying a concern with the pace of DTE's review of applications to participate in Rider 16 Net Metering, and with an apparent conflict between twenty-year SolarCurrents contracts and the 10-year grandfathering of participation in Rider 16. Finally, Mr. Jester commented on DTE's proposed low-income pilot, recommending that participation be expanded, that participants be able to obtain 100% renewable energy, and that the Commission require additional reporting. Mr. Jester presented Exhibits MEC-59 to MEC-68 in support of his testimony.

<u>Karl G. Boothman</u>

Mr. Boothman is a consultant with 5 Lakes Energy LLC. Mr. Boothman's testimony is transcribed at 9 Tr 3862-3881. His qualifications are set forth at 9 Tr 3864-3865 and in Exhibit MEC-69. Mr. Boothman explained the analysis he undertook to allocate DTE's production costs to various categories of generating plants to facilitate the application of the equivalent peaker and probability of dispatch cost of service studies completed by other MEC Coalition witnesses. Mr. Boothman presented Exhibits MEC-70 to MEC-74 in support of his testimony.

David L. Gard

Mr. Gard is a Senior Consultant at 5 Lakes Energy LLC. Mr. Gard's testimony is transcribed at 9 Tr 3883-3898. His qualifications are set forth at 9 Tr 3885-3886 and in Exhibit MEC-75. Mr. Gard performed a production cost analysis using the probability of dispatch method and explained his analysis. He also presented Exhibits MEC-76 through MEC-84 in support of his testimony.

Richard Bunch

Mr. Bunch is a Senior Consultant at 5 Lakes Energy LLC. Mr. Bunch's testimony is transcribed at 9 Tr 3900-3913, with a confidential version in the confidential record. His qualifications are set forth at 9 Tr 3902-3903 and in Exhibit MEC-85. Mr. Bunch performed a production cost analysis using the equivalent peaker method and explained his analysis. He also presented Exhibits MEC-86 and MEC-87 in support of his testimony, with a confidential version of Exhibit MEC-86.

F. ABATE

ABATE presented the testimony of four witnesses. The review that follows begins with Mr. Dauphinais, because he provided ABATE's overall revenue requirement calculation.

James R. Dauphinais

Mr. Dauphinais is a consultant and a Managing Principal with the firm of Brubaker & Associates, Inc. Mr. Dauphinais's testimony, including his direct, rebuttal, and cross-examination, is transcribed at 7 Tr 1630-1795. His qualifications are set forth at 7 Tr

1636-1638 and 1659-1663. After introducing the testimony of other ABATE witnesses from his firm, he presented a revenue requirements calculation incorporating the recommended adjustments of all ABATE witnesses of $117.6, with an additional adjustment proposed to nuclear decommissioning expense. Mr. Dauphinais addressed the level of recent DTE capital expenditures and recommended a separate review of the use of projected test years in rate case. He also took issue with DTE corporate membership expenses. Addressing cost of service allocations, Mr. Dauphinais testified that although ABATE continues to believe a 4CP-100 method is the most appropriate to allocate fixed production costs, it is not actively opposing in this case the company's use of the 4CP 75-0-25 method adopted in past cases. He presented Exhibits AB-1 and AB-2 containing data regarding DTE's recent capital expenditures in support of his testimony.

Jessica A. York

Ms. York is a Senior Consultant with the firm of Brubaker & Associates, Inc. Ms. York's testimony is transcribed at 7 Tr 1919-1948. Her qualifications are set forth at 7 Tr 1921 and 1946-1948. She recommended several adjustments to DTE's projected capital and O&M expenses. She objected to DTE's use of a 3% labor escalation factor to derive projected test year O&M, recommending reliance only on the Consumer Price Index (CPI). She also recommended excluding contingency amounts from capital expense projections. Addressing specific projections, she recommended that capital expenses for the Monroe Dry Fly Ash Conversion and the Monroe Bottom Ash Basin Closure projects be rejected, along with projected capital costs associated with an LP turbine blade replacement at Belle River unit 2, a transformer replacement at the Greenwood Energy

Center, and stator outage work at Monroe unit 4. She presented Exhibits AB-7, AB-8 and AB-9 in support of her testimony.

Amanda M. Alderson

Ms. Alderson is a consultant and Associate in the firm Brubaker & Associates, Inc. Ms. Alderson's testimony is transcribed at 7 Tr 1799-1821. Her qualifications are set forth at 7 Tr 1801-1802 and 1820-1821. She recommended that DTE's prepaid pension asset be excluded from working capital, testifying that DTE did not establish that this pension asset was fully funded by investor capital or that it provides benefits to ratepayers. She also took issue with DTE's request to recover costs for an as-yet incomplete nuclear decommissioning study, also finding the cost figures unsupported. She recommended cost recovery be limited to actual expenditures for the third-party consultant. Ms. Alderson also addressed DTE's DR program, objecting that its projected capital expenditures materially differ from those presented in its Integrated Resource Plan (IRP). She recommended that DTE be given an opportunity to address certain expenditures further in rebuttal, but that proposed expenditures for the DTE Insight be rejected. Noting DTE's request for a Financial Incentive Mechanism for DR investments, she testified that if the Commission grants such an incentive mechanism, it should not also provide a return on capital investments.

Christopher C. Walters

Mr. Walters is a Senior Consultant with the firm Brubaker & Associates, Inc. Mr. Walters's testimony, including his direct and rebuttal, is transcribed at 7 Tr 1822-1918. His qualifications are presented at 7 Tr 1824-1825 and 1900-1902. Mr. Walters recommended that the Commission set a return on equity for DTE of 9.2%, based on a recommended range of 8.7% to 9.7%, and presented testimony and Exhibits AB-10 through AB-28 in support of his analysis. He also presented a critique of the analyses underlying Dr. Villadsen's recommendation for DTE. Additionally, Mr. Walters recommended that the Commission accelerate the return of unprotected excess deferred tax balances resulting from the 2017 TCJA.

G. <u>ELPC and NRDC</u>

ELPC sponsored a witness jointly with NRDC. ELPC also sponsored witnesses as part of the ELPC Group, discussed in section H below.

<u>Christopher Villareal</u>

Mr. Villareal is the President of the consulting firm Plugged In Strategies. Mr. Villareal's testimony is transcribed at 9 Tr 2683-2720. His qualifications are set forth at 9 Tr 2685-2687 and in Exhibit ELP-1. His testimony addressed DTE's proposed distribution system planning process and projected capital and O&M expenditures. Testifying to his opinion that DTE's distribution plan and planning process retains shortcomings that he identified in Case No. U-20162, Mr. Villareal recommended that the Commission decline to rely on the Electric Power Research Institute (EPRI) report or DTE's five-year distribution plan as support for DTE's application. He further recommended that the Commission withhold a portion of DTE's projected tree-trimming costs until DTE actually performs the tree-trimming or improves its reliability metrics. He also recommended that DTE be required to use independent third-party testing to ensure that interoperability standards are met, and that DTE be required to consider market-based or non-utility non-wires alternatives (NWA). Finally, he recommended that DTE explicitly align its next five-year plan with a U.S. Department of Energy (DOE) framework, with a comparison to other utilities.

H. <u>ELPC, Ecology Center, SEIA, Vote Solar</u>

<u>William D. Kenworthy</u>

Mr. Kenworthy works for Vote Solar as Regulatory Director, Midwest. Mr. Kenworthy's testimony is transcribed at 9 Tr 2722-2738. His qualifications are set forth at 9 Tr 2724-2727 and in Exhibit ELP-3. He presented analysis of DTE's proposed Low Income Renewables Pilot, recommending that it be rejected and that DTE be directed to propose a new program in its next voluntary green pricing program case that provides low-income customers a more meaningful opportunity to access the benefits of renewable energy, after consultation with stakeholders. While commending DTE for acknowledging the need for programs to provide access to what he referred to as the clean energy economy, Mr. Kenworthy objected that DTE's proposed pilot serves more of a marketing purpose for DTE, not integrated into the rest of the company's low-income efforts, and not providing additional renewable energy to DTE's system. He also objected to the proposed pilot's reliance on the MIGreenPower program (MIGP), which he believes does not adequately value distributed generation resources, and thus is concerned that the pilot will not provide adequate savings. Additionally, he characterized the cap on program participants as "arbitrarily low."

I. <u>Soulardarity</u>

<u>Jackson Koeppel</u>

Mr. Koeppel is the Executive Director of Soulardarity. Mr. Koeppel's testimony is transcribed at 6 Tr 1396-1444. His qualifications are set forth at 6 Tr 1397-1399. Mr.

Koeppel testified that DTE inequitably invests in safety and reliability in low-income and people-of-color communities, and objected to residential rate increases that do not redress this disparity. He also objected to DTE's proposed return on equity and to greater streetlighting rate increases for communities with above-ground wiring, testifying that financially-struggling communities are more likely to have above-ground wiring. Mr. Koeppel also proposed modifications to the company's Fixed Bill Pilot program and objected to the Low-Income renewables pilot, proposing instead reliance on community solar. He sponsored Exhibits SOU-1 through SOU-40, containing numerous articles and other background information on energy affordability and sustainability.

J. Walmart

Steve W. Chriss

Mr. Chriss is Director of Energy Services for Walmart. Mr. Chriss's testimony is transcribed at 9 Tr 2658-2680. His qualifications are set forth at 9 Tr 2660-2661 and in Exhibit WAL-1. After describing Walmart's operations in Michigan and within DTE's service territory, Mr. Chriss recommended that the Commission closely examine the company's revenue requirement in light of its impact on customers, the reduced risk associated with Michigan's regulatory framework from the use of projected test years and the including of Construction Work in Progress (CWIP) in rate base, and returns on equity recently approved by this Commission and other regulatory commissions. Mr. Chriss sponsored 3 exhibits in addition to his resume, Exhibits WAL-2 through WAL-4, to support his stated concerns with the level of the company's proposed return on equity. Mr. Chriss also indicated that Walmart was not opposing DTE's proposed production cost method or other components of its cost of service model, or the company's proposed rate design for

Rate D11. He further testified that if the Commission determines to move away from the currently-approved production cost allocation method, it would be more appropriate to use an average and excess (A&E) method.

K. Utility Workers Union of America Local 223, AFL-CIO

The UWUA sponsored the testimony of two witnesses.

Jonathan Harmon

Mr. Harmon is Executive Director for the UWUA Power for America Training Trust Fund ("P4A"). Mr. Harmon's testimony is transcribed at 9 Tr 2740-2746. Mr. Harmon expressed a concern that the aging of the national workforce necessary to operate the nation's utility systems requires increased hiring and training to maintain reliable service and public and worker safety. Mr. Harmon reviewed information previously presented by DTE, and identified training programs available through P4A he believes would be beneficial to DTE, its employees and customers, and the public. He recommended that the Commission carefully examine the projected training costs DTE included in this rate case, further require DTE to document its training plans in light of its aging workforce, and to consider external funding that would be available through P4A. He presented Exhibits UAW-1 through UAW-8 in support of his testimony.

Michael Smith

Mr. Smith is the President of Utility Workers Union of America, AFL-CIO, Local 223. Mr. Smith's testimony is transcribed at 9 Tr 2748-2752.His responsibilities include managing the day-to-day operations of Local 223. He presented data showing the age demographics of the union in Exhibits UWUA-9 and UWUA-10. Citing reports in Exhibits UWUA-1 through UWUA-6, Mr. Smith testified that the aging workforce concerns at the national level are also faced by DTE, with additional challenges caused by recent retirements at DTE. He recommended that the Commission require DTE to document how it plans to deal with concerns raised by its aging workforce, which Mr. Smith characterized as "an impending crisis." He reiterated Mr. Harmon's recommendation that DTE be required to partner with P4A to ensure that necessary funds are externally funded and available.

L. Foundry Association of Michigan

Alexander J. Zakem

Mr. Zakem is an independent consultant providing services to clients including members of Energy Michigan, Inc. Mr. Zakem's testimony is transcribed at 9 Tr 2754-2770. Mr. Zakem's qualifications are set forth at 9 Tr 2755-2756 and in his resume, Exhibit FAM-1. Mr. Zakem addressed DTE's proposed distribution charges for two riders, R1.1 Alternative Metal Melting Rider and R1.2 Electric Process Heat Rider, focusing on subtransmission and transmission voltage levels with proposed increases of 159% and 97% respectively. Mr. Zakem objected that DTE had not provided any explanation for the large increases, calling for further investigation. He also highlighted the allocation of costs for property taxes on meters and services, the proposed annual service charge for the one customer on Rider R1.2, and the proposed collection of a service charge for both the underlying Rate D11 Primary Supply and the R1.2 rider. He recommended that the increases be denied, and that the service charges be set at the primary voltage service charge or in the alternative, remain at the present level. Mr. Zakem also addressed the proposed tariff changes for Rider R1.1 and Rider R1.2 and Interruptible Rate D8, finding all but one of the changes comprehensive and clear. He objected to DTE's proposed addition of a “capacity deficiency” criterion for interruption in addition to the “system integrity” criterion, and recommended that it be deleted.

M. <u>Great Lakes Renewable Energy Association (GLREA)</u>

GLREA sponsored the testimony of two witnesses.

<u>Robert </u>Rafson

Mr. Rafson is a member of the GLREA Regulatory Affairs Committee and the owner of Chart House Energy, LLC. Mr. Rafson’s testimony is transcribed at 9 Tr 2776-2788. His qualifications are set forth at 9 Tr 2777-2779 and in his resume, Exhibit GLREA-1. He addressed DTE’s proposed rates and rules for DG customers under DG Rider 1.8, contending it is not reasonable. Mr. Rafson specifically took issue with the inflow/outflow rate methodology and valuation, the cap on the DG program, the differentiation between system sizes, the restricted application of the outflow credit to the follow month’s bill, and the energy credit valuation, and he recommended that DTE purchase renewable energy credits. Mr. Rafson objected that DTE did not address the impact of its proposed rate increase on distributed generation or low-to-moderate-income customers.

<u>John Richter</u>

Mr. Richter is on the Board of Directors for GLREA and is also its policy analyst. Mr. Richter’s testimony is transcribed at 9 Tr 2789-2806, including his direct and his stricken rebuttal testimony. His credentials are set forth at 9 Tr 2790-2792 and in his resume, Exhibit GLREA-3. He recommended that the Commission establish a time-of-use tariff for residential customers in a contested case, rather than in the *ex parte* proceeding proposed by DTE, and preferably in this rate case. He also recommended that the Commission revise the outflow credit for DG customers, recommending a detailed cost of service study be undertaken. In his view, DTE's proposal violates principles articulated by Bonbright.

Mr. Richter also provided rebuttal testimony that was stricken, but is included in the transcript for completeness.

N. Residential Customer Group

Geoffrey C. Crandall

Mr. Crandall is Vice President of the consulting firm MSB Energy Associates, Inc. Mr. Crandall's testimony is transcribed at 9 Tr 2809-2825. His qualifications are set forth at 9 Tr 2810-2811 and in his resume, Exhibit RCG-1. Mr. Crandall recommended the use of an historical test year, adjusted for known changes and objected that the projected test year underlying DTE's application is "outside the time parameters" in MCL 460.6a. Mr. Crandall also testified regarding the AMI meter opt-out program, objecting that DTE had not provided a benefit-cost analysis of its AMI meter installation, or provided accurate costs for the non-transmitting up-front and monthly charges. He discussed his concern that customers who choose to opt out are being asked to pay AMI meter costs as well as the charges under the opt-out program. Citing other states who do not charge customers choosing to opt out as shown in Exhibits RCG-2 and RCG-3, he recommended a revised tariff, Exhibit RCG-4. Citing the settlement agreement approved in Case No. U-20084, Mr. Crandall also recommended that the Commission ensure all costs to comply with that order are excluded from rates.

O. Kroger

Justin Bieber

Mr. Bieber is a Senior Consultant for Energy Strategies, LLC. Mr. Bieber's testimony, including his direct and rebuttal, is transcribed at 8 Tr 2151-2240. His qualifications are set forth at 8 Tr 2155-2156. Mr. Bieber's direct testimony focused in part on DTE's reliability metrics. Citing statistics on all-weather SAIDI and SAIDI excluding major event days, Mr. Bieber recommended a Reliability Incentive Mechanism (RIM) that would provide a credit to customers until DTE achieves at least one year of average reliability performance, suggesting a credit amount equivalent to the value of 10 basis points of the company's authorized return on equity, which he estimated at $9.4 million. Turning to distribution rate design, Mr. Bieber also supported the method DTE used to calculate primary voltage customer charges as consistent with prior orders. Mr. Bieber presented Exhibit KRO-1 in support of his direct testimony.

P. Rebuttal

1. Consumers Energy

Consumers Energy presented the rebuttal testimony of Ms. Crozier, Ms. Suchta, Ms. Uzenski, Mr. Morren, Ms. Leslie, Mr. Burgdorf, Mr. Davis, Mr. Bruzzano, Ms. Robinson, Mr. Cejas Goyannes, Ms. Rivard, Mr. Griffin, Mr. Clinton, Mr. Cooper , Ms. Johnson, Mr. Leuker, Mr. Solomon, Dr. Villadsen, Mr. Lacey, Mr. Brasil, Mr. Dennis, Ms. Holmes, and Mr. Bloch.

Ms. Crozier provided rebuttal testimony on a multitude of topics, further addressing time-of-use rates in response to testimony by Staff witness Isakson and GLREA witness Richter; addressing the effective date of rates approved in a final order in this case in response to testimony by Staff witness Isakson, addressing Staff proposals that DTE agree to remove the cap on the size of DG eligible for net metering and that certain bill credits be automated; and addressing cost allocation testimony by witnesses Jester, Dismukes, and Bunch; witness Crandall's proposed reliance on an historical test year; AG witness Coppola's recommendation to disallow capitalized incentive payments; ABATE witness Walters's proposed regulatory plan; Dr. Letendre's recommendation for additional analysis of Belle River retirement options in the company's next rate case; and UWUA witnesses Smith and Harmon recommendations regarding worker training.

Ms. Suchta responded to ABATE witness Walters's recommendation to accelerate the return of unprotected excess deferred tax balances in her rebuttal testimony. She took issue with the accuracy of his net present value comparison, presenting a revised version of Exhibit AB-28 in Exhibit A-42. Based on this revised analysis, she testified that ratepayers would be better off under the amortization schedule proposed by the company.

In her rebuttal testimony, Ms. Uzenski recommended a modification of Staff witness Gerken's proposed reduction in working capital related to intercompany accounts, and objected to ABATE witness Alderson's proposal to exclude the company's prefunded pension obligation from working capital, additionally proposing the creation of regulatory asset/liability account to track differences between projected and actual expenses. Regarding O&M expense, Ms. Uzenski objected to the recommendation by Kroger witness Bieber to exclude non-labor inflation from projected O&M; Ms. Uzenski also objected to Staff adjustments to injuries and damages and uncollectible expense recommended by Ms. McMillan-Sepkoski; Ms. Uzenksi disputed ABATE witness Dauphinais's recommended exclusion of the company's corporate memberships; and she recommended a modification to Staff witness Welke's adjustment for the plug-in vehicle amortization. Ms. Uzeksi also responded to RCG witness Crandall's concerns regarding expenses associated with the settlement agreement in Case No. U-20084, testifying that no such costs are included in the company's requested revenue requirement. Ms. Uzenski presented Exhibit A-40 in support of her testimony.

Mr. Morren addressed the reductions in projected generating plant capital expense proposed by Attorney General witness Coppola, ABATE witness York, and the MEC coalition witness Letendre, and the reductions in projected O&M expenses also recommended by Mr. Coppola. He also objected to Dr. Letendre's recommendation that DTE provide additional information on Coal Combustion Residual costs in the next rate case. He provided additional information regarding the company's proposed capital and O&M expenditures in Exhibit A-39.

In their rebuttal testimony, Ms. Leslie and Mr. Burgdorf further addressed Dr. Letendre's recommendation that the Commission disallow recovery of future capital expenditures for River Rouge unit 3. Ms. Leslie discussed DTE's modeling, and Mr. Burgdorf disputed Dr. Letendre's testimony concluding that DTE's capacity price forecasts are inflated, and disputed that DTE erroneously used the MISO Capacity Import Limit (CIL) in its PACE forecast. He presented additional documentation in support of his testimony in Exhibit A-32.

In his rebuttal testimony, Mr. Davis addressed the reductions proposed by ABATE witness Alderson to DTE's projected O&M funding for a nuclear decommissioning study. Testifying to the information DTE had previously provided in support of its projected expense, in response to discovery, with a summary in his Exhibit A-34.

Mr. Bruzzano presented rebuttal testimony addressing Attorney General witness Coppola's recommended reductions to DTE's capital and O&M expense projections. He also addressed the concerns raised by several witnesses regarding DTE's distribution system operations and plans, including: MEC Coalition witness Jester's recommendations and comments regarding DTE's distribution system plan and recommendation to file new plan in 6 months; ELPC witness Villarreal's concerns regarding the EPRI report on DTE's distribution system planning, investment strategy based on five-year plan, and the need for interoperability testing; Kroger witness Bieber's recommendation to implement a Reliability Incentive Mechanism; and Soulardarity witness Koeppel's concerns that DTE's investments in safety and reliability are inequitable. He presented Exhibit A-31 along with his rebuttal.

In her rebuttal testimony, Ms. Robinson addressed testimony by Staff witness Dr. Wang, objecting to the additional data she recommended DTE be required to provide, and objecting to her recommended cost disallowances. She also addressed RCG witness Crandall's recommendations regarding the AMI meter opt-out program, citing prior Commission orders and indicating that DTE plans to file for review of the opt-out charges in a separate docket before the end of the third quarter of 2020.

Mr. Cejas Goyannes responded to proposed reductions in DR capital spending and program modifications recommended by Staff witness Isakson, and ABATE witness Alderson. While continuing to recommend approval of all expenditures included in the company's projected revenue requirement, he did propose that DTE meet with Staff periodically to discuss the company's progress on pilot initiatives. He also proposed to modify the fees and corresponding additional revenue recommended by Mr. Isakson for the Energy Bridge program, presenting his revised calculations in Exhibit A-37.

Ms. Rivard responded to Attorney General witness Coppola's recommendations to reduce the tree trimming expense allowance and Surge program funding requested by DTE. She testified that failure to include an inflationary increase would reduce tree trim miles, and disputed that increased Surge funding should await a greater showing of benefits, citing her direct testimony. In response to ELPC witness Villareal's recommendation that the Commission adopt a performance-based ratemaking mechanism, Ms. Rivard presented a chart to show that DTE has consistently spent tree trimming dollars provided in rates, and cannot defer spending under the existing Surge program. Ms. Rivard also indicated that DTE would accept Staff witness Evans's recommendation that DTE provide additional reporting on the availability of tree trimmers.

Mr. Griffin's rebuttal testimony responded to proposed reductions to DTE's projected capital expenditures made by Staff witness Wang and Attorney General witness Coppola. Mr. Griffin contended that the company's projections should be adopted without modification, and presented Exhibit A-43 in support of his rebuttal testimony.

In his rebuttal testimony, Mr. Clinton responded to testimony from Staff witness Wang and MEC Coalition witness Jester regarding the Charging Forward program, to testimony from Staff witness McMillan-Sepkoski and Attorney General witness Coppola regarding merchant fee expenses, and to critiques of the company's proposed Fixed Bill Pilot and Low-Income Pilot from Staff witnesses Isakson and Banks, Mr. Coppola, MEC Coalition witness Jester, ELPC witness Kenworthy, and Soulardarity witness Koeppel.

Mr. Cooper addressed the recommendations to exclude projected incentive compensation expenses made by Staff witness McMillan-Sepkoski and Attorney General witness Coppola, and the recommendation by ABATE witness Alderson to exclude the company's prepaid pension obligation from working capital. He presented additional supporting information in Exhibit A-33.

In her rebuttal testimony, Ms. Johnson objected to Staff's and the Attorney General's proposed reductions in projected uncollectible expense, and to Staff's proposed reductions in the Residential Income Assistance (RIA) and Low-Income Assistance (LIA) customer count projections. She also addressed critiques of the company's low-income programs presented by MEC Coalition witness Colton.

In his rebuttal testimony, Mr. Leuker objected to Mr. Coppola's recommended adjustments to DTE's residential and commercial sales forecasts, also sponsoring Exhibit A-38 in support of the forecasts in his direct testimony.

Mr. Solomon responded to Staff's proposed reductions in short-term and long-term debt costs, objecting to the use of updated information on the basis that interest rates are constantly changing. He also objected to Mr. Coppola's proposal increase in the quantity of short-term debt, contending adequate liquidity is provided in DTE's proposal, and he objected to ABATE witness Walters's proposed acceleration of the amortization of excess ADIT balances.

Dr. Villadsen's rebuttal testimony addressed alternative recommendations on the cost of equity made by Staff witness Megginson, Attorney General witness Coppola, ABATE witness Walters, contending the recommendations of those witnesses are too low. She also responded to critiques of her analyses presented by those witnesses.

Mr. Lacey addressed recommendations from witnesses for the Attorney General and the MEC Coalition, objecting to their proposed allocation methods for production costs. Mr. Lacey also objected to the Attorney General's recommended revision to subtransmission cost allocation. Mr. Lacey stated his agreement with Staff witness Gottschalk's testimony regarding customer charges. He presented Exhibit A-36 in support of his rebuttal testimony, including a revision to Exhibit MEC-66.

In his rebuttal testimony, Mr. Brasil addressed Mr. Jester's recommendation that DG outflows be treated as offsetting inflows in future cases, indicating the company will consider the use of outflows in its next case. Mr. Brasil also addressed Professor Dismukes's recommendations regarding the allocation of demand-related secondary-voltage distribution system costs based on non-coincident peak demand, disagreeing that a change is necessary or appropriate.

Mr. Dennis addressed equitable concerns raised by Mr. Koeppel for Soulardarity and Mr. Dismukes's alternative proposal to limit residential rate increases. Mr. Dennis disagreed with Staff witness Matthews's testimony that pricing for the distributed generation program is cost-based, and objected to GLREA's recommendations, which he characterized as a return to true net metering. Mr. Dennis also objected to Mr. Jester's proposal to allow SolarCurrents customers to remain on Rider 16 for the remaining 20-year term of the SolarCurrents contracts.

In her rebuttal testimony, Ms. Holmes addressed Mr. Jester's objection to the revised loss factor she proposed. She disputed that her recommendation was based on an outdated loss factor study. She also objected to Staff's adjustment to present revenue as proposed by Mr. Isakson, based on the loss factor explained by Ms. Shi. She presented audit responses on this topic in her Exhibit A-35.

In his rebuttal testimony, Mr. Bloch explained his objections to the recommendation by MEC Coalition witness Jester to revise the CIAC calculations, and responded to FAM witness Zakem's objections to DTE's proposed capacity deficiency provision for the interruptible Rate D8.

2. Staff

Staff presented the rebuttal testimony of four witnesses. Mr. Gottschalk and Mr. Isakson presented rebuttal testimony addressing cost allocation and rate design. Mr. Gottschalk responded to testimony regarding the production cost allocator made by MEC Coalition witnesses Jester and Boothman, Walmart witness Chriss, Kroger witness Bieber, and ABATE witness Dauphinais. He objected to Mr. Jester's description of the history of Commission orders on this issue and disputed that a POD method will ultimately be required. He also disagreed with Mr. Bieber's and Mr. Chriss's characterization of the current method as allocating production capacity costs, rather than non-fuel production costs associated with generating plants, and with Mr. Chriss's assertions regarding the use of an energy allocator. Acknowledging testimony from Kroger witness Mr. Bieber and ABATE witness Dauphinais regarding other methods, he testified that Staff supports retaining the current method. Finally, he disagreed with ELPC witness Kenworthy that the cost of the low-income renewables pilot proposed by DTE would be borne entirely by the residential class.

In his rebuttal testimony, Mr. Isakson objected to the alternative recommendation made by Professor Dismukes that the Commission limit residential rate increases to 1.15

times the overall system average, citing MCL 460.11(1). Mr. Isakson also disputed GLREA witness Richter's concern that summer on-peak rates would have the effect of increasing costs to customers, contending that the goal is only to recover the same revenue requirement. Addressing DTE's fixed-bill pilot proposal, Mr. Isakson reiterated Staff's objection to the pilot in response to Soulardarity witness Koeppel's proposed revisions. He also took issue with Mr. Koeppel's stated concern with differential rate increases for different residential rate schedules. Addressing lighting rates, Mr. Isakson took issue with Mr. Koeppel's concern with the greater rate increase for streetlighting served by aboveground relative to underground lines, testifying that the rate differences are cost-justified.

Mr. Isakson also found fault with Mr. Colton's analysis of the affordability of DTE's electric rates, agreeing that DTE failed to provide certain data but asserting "[T]he absence of appropriate data is not an excuse to rely on a flawed analysis." See 9 Tr 3147. (His principal objection was that low-income customers may have an average bill that is below the average bill for all residential customers. He also objected to Mr. Colton's use of regional data.) He also disputed that the utility and its customers would be better off if low-income customer disconnections could be avoided. While recognizing DTE's LIA pilot could be improved, Mr. Isakson did not recommend any changes. He did recommend that if the Commission adopts Mr. Colton's recommendations, that the Commission require additional planning by DTE prior to implementation. Mr. Isakson also recommended that the Commission reject Mr. Colton's recommendation regarding the RIA program, disputing that other customers "fund" the RIA credits, and disputing that a fund is available to spread credits to a greater number of customers.

Staff also presented the testimony of two witnesses who did not present direct testimony in this case.

Kevin S. Krause

Mr. Krause is an auditor in the Rates and Tariffs section of the MPSC's Regulated Energy division. Mr. Krause's rebuttal testimony is transcribed at 9 Tr 3381-3391. His qualifications are set forth at 9 Tr 3382-3384. In his rebuttal testimony, Mr. Krause addressed testimony regarding the DG tariff Rider 18, taking issue with GLREA witness Rafson's reference to "benefits" in the context of a cost of service study, and disputing that the inflow/outflow method is unreasonable. He also objected to treating DG customers as a separate class for purposes of a cost of service study, disagreed that the cap on participation is "self-imposed" by DTE, and disagreed that all DG project sizes should be treated equally. Mr. Krause also disputed GLREA witness Richter's and MEC Coalition witness Jester's concerns with the outflow method. Finally, Mr. Krause addressed Mr. Jester's recommendations regarding line losses, contending that Mr. Jester focuses on engineering losses and does not consider other reasons for differences between generation and sales, including meter inaccuracy, differences between estimated and actual service, and theft.

Nicholas M. Revere

Mr. Revere is Manager of the Rates and Tariffs Section of the MPSC's Regulated Energy Division. Mr. Revere's rebuttal testimony is transcribed at 9 Tr 3393-3400. His qualifications are set forth at 9 Tr 3394-3397. In his rebuttal testimony, Mr. Revere also addressed Mr. Jester's testimony regarding DG outflow, disputing that DG reduces generation costs, characterizing Mr. Jester's proposal as violating principles of cost-causation. He nonetheless agreed that a DG customer's outflow may reduce the use of the transmission system and portions of the distribution system by the class to which that customer belongs.

3. Attorney General

The Attorney General presented rebuttal testimony from Professor Dismukes and Mr. Coppola. In his rebuttal testimony, Professor Dismukes addressed the testimony of several other witnesses regarding the cost of service study, including testimony by Mr. Jester on behalf of the MEC coalition, Mr. Chriss on behalf of Walmart, and Mr. Dauphinais on behalf of ABATE. He presented a comparison of alternative production plant allocations in Exhibit AG-2.14, originally filed as Exhibit AG-R2.

In his rebuttal testimony, Mr. Coppola addressed the return on equity recommendations made by Staff witness Megginson, objecting to his use of a projected market risk premium and to his reliance on authorized returns from 2017.

4. ABATE

ABATE presented rebuttal testimony from Mr. Dauphinais and Mr. Walters. In his rebuttal testimony, Mr. Dauphinais addressed proposals to modify the allocation of production and subtransmission costs presented by witnesses for the Attorney General and the MEC Coalition. Mr. Dauphinais testified that these cost of service proposals would unnecessarily shift $40 million to $187 million of cost responsibilities from residential and commercial secondary customers to primary class customers, and recommended that the proposals be rejected as not resulting in rates equal to the cost of service. He also objected to proposals by Attorney General witness Dismukes to revise the distribution of revenue to the rate classes. He proposed that if the Commission is inclined to refine the production cost allocator, it explore use of the Average & Excess (A&E) cost method in the next rate case. He presented Exhibits AB-29 through AB-32 in support of his rebuttal testimony.

In his rebuttal testimony, Mr. Walters took issue with the recommendations of Staff witness Megginson, testifying that Mr. Megginson used certain inaccurate inputs and made other errors in his analysis. He presented Exhibits AB-33 and AB-34 in support of his rebuttal testimony.

5. Kroger

Kroger presented rebuttal testimony from Mr. Bieber. He addressed recommendations to revise the production cost allocation method made by Attorney General witness Dismukes, MEC Coalition witnesses Jester, Boothman, Bunch, and Gard. Mr. Bieber recommended that the alternative methods recommended by these witnesses be rejected, and further testified that should the Commission desire to adopt an alternative, he recommends the A&E method or other method that relies on excess demand to allocate capital costs. Mr. Bieber also recommended that the Commission reject Professor Dismukes's proposal to allocate subtransmission plant on the same basis as transmission plant, or in the alternative to limit the allocation to 120 kv lines. Addressing Mr. Jester's recommendations regarding performance-based ratemaking, Mr. Bieber testified that his proposed RIM is consistent with holding DTE accountable for its performance. He recommended that if the Commission does not adopt his proposed RIM, it nonetheless pursue an alternative such as Mr. Jester's recommendation. He presented Exhibits KRO-2 and KRO-3 in support of his rebuttal testimony.

Q. **Overview**

The parties generally take positions consistent with the recommendations of their witnesses; Staff and DTE making adjustments to certain positions in their briefs, and MEC and Soulardarity support positions taken by other parties in their briefs as discussed below.

Section III below addresses the legal standards applicable to this case. Section IV discusses choice of test year to be used in setting rates. Section V addresses rate base, including the appropriate net plant and working capital amounts. Section VI addresses the rate of return, including the appropriate capital structure to use in setting rates and the individual cost elements to use in determining the overall cost of capital. Section VII addresses the test year adjusted net operating income including the sales and revenue projections and the O&M and other expense projections. Section VIII discusses other revenue requirements-related issues. Section IX summarizes the revenue requirement analysis. Section X addresses the cost of service studies and cost allocation issues raised by the parties. Section XI addresses rate design.

III.

LEGAL STANDARDS

Before addressing the disputes among the parties regarding revenue requirements, cost allocation, rate design, and other matters, it is appropriate to review certain legal issues. It is axiomatic that the Commission is required to set rates that are just and reasonable. Ratemaking is essentially a legislative function, and the Commission is not bound by any particular method or formula in exercising this legislative function.

The Commission is required to balance the interests of the public utility and the consuming public.

DTE begins its brief with a discussion of the legal standards applicable to rate cases. Some of DTE's argument is not controversial. Addressing the burden of proof, however, DTE contends that the Commission should apply what has been labeled as the "substantial evidence" test, making the identical argument, using the same language, this ALJ and the Commission have previously rejected. DTE argues:

> The Michigan Constitution requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, Art 6, § 28. Expert testimony is "substantial" only if it is offered by a qualified expert who has an informed and rational basis for his or her view, even if other experts disagree. *Great Lakes Steel v Public Service Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983). Therefore, substantial evidence is evidence "that a reasoning mind would accept as sufficient to support a conclusion." *Monroe v State Employees' Retirement Sys*, 293 Mich App 594, 607; 809 NW2d 453 (2011). However, "substantial evidence is 'more than a mere scintilla' but less than a 'preponderance' of the evidence." *Huron Behavioral Health v Dep't of Behavioral Health*, 293 Mich App 491, 497; 813 NW2d 763 (2011). *Thus, the applicable standard of proof for purposes of determining whether the Company's proposals or recommendations are reasonable and prudent is the "substantial evidence" standard, which is a lighter standard than even the "preponderance of the evidence" standard, which itself is a lighter standard than the "beyond a reasonable doubt" standard that is only applicable to criminal proceedings*. For the reasons discussed below, DTE Electric's proposals and recommendations in this case more than satisfy the "substantial evidence" standard as demonstrated by the record.[7]

The Attorney General takes issue with DTE's claim that it should prevail if it presents "substantial evidence" in support of its recommendations, rather than expecting the Commission to weigh the evidence and find facts in accordance with the

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[7] See DTE brief, pages 8-9 (footnotes omitted, emphasis added); also see DTE brief, Case No. U-18014, pages 11-12. Also see DTE brief, Case No. U-20162, pages 9-10.

preponderance of the evidence. In her reply brief, after pointing out that the Attorney General has made a similar clarification in several prior cases, she argues:

> In its initial brief, DTE argues that "the applicable standard of proof for purposes of determining whether the Company's proposals or recommendations are reasonable and prudent is the 'substantial evidence' standard, which is a lighter standard than even the 'preponderance of the evidence' standard, which itself is a lighter standard than the 'beyond a reasonable doubt' standard that is only applicable to criminal proceedings."
>
> It bears reiterating here that, regardless of whether Staff or any Intervenor presents any information, evidence, or testimony challenging a specific issue, DTE has the burden of proof with regard to that issue. The obligation of proving any fact lies upon the party who substantially asserts the affirmative of the issue. A plaintiff always has the burden of proving its cause of action. In administrative cases, a party seeking relief must prove his, her, or its claim by a preponderance of the evidence. Likewise, in MPSC Cases, a utility has the burden of proof by a preponderance of the evidence. This is further supported by the Michigan Supreme Court, which has explained that an administrative agency's findings of fact are similar to a trial court's findings of fact, which similarly uses a preponderance of evidence standard. Moreover, the MPSC may disbelieve even uncontradicted evidence. When the burden of proving a fact falls on one party, then the other party does not have the burden of proving the opposite fact.
>
> Although the standard of review on appeal for a Commission decision is competent, material, and substantial evidence on the whole record, that is not the burden of proof standard for DTE in order to support its $343 million rate increase request. The Commission should keep in mind that DTE must present sufficient evidence to support its burden of proof for a project or projected costs. It is entirely appropriate for an intervenor to argue, and for the Commission to find, that DTE has not presented sufficient evidence to support its burden of proof for a specific project or proposal.[8]

The Attorney General cites several cases, including *Dillon v Lapeer State Home & Training School*, 364 Mich 1, 8; 110 NW2d 588 (1961); and *BCBSM v Governor*, 422 Mich

[8] See Attorney General reply brief, pages 4-6 (footnotes omitted).

1, 88-89; 367 NW2d 1 (1985), as well as prior Commission orders, including the Commission's June 7, 2012 order in Case No. U-16794.

In its January 31, 2017 order in Case No. U-18014, the Commission rejected DTE's claim that it should prevail on an issue if it has presented 'substantial evidence'. In an effort to resolve this issue expeditiously, the Commission's lengthy discussion is quoted in full:

> The ALJ addressed this issue, finding that the Attorney General's analysis was correct and that DTE Electric had confused the burden of proof in an administrative proceeding with the standard of review for an appellate court:
>
> > [T]he Commission must apply what has been labeled the "preponderance" standard. If the Commission does this, then reviewing courts will not substitute their judgment for the Commission's judgment, but will defer to the Commission's findings of fact if those findings are supported by "substantial evidence." The judicial review for "substantial evidence" is a called a deferential standard of review because the reviewing court does not itself weigh conflicting evidence, and has explained that a finding of fact by the Commission will be upheld if it is supported by any competent evidence that is "more than a scintilla". * * * It is understandable that persons or parties not familiar with the basic principles of administrative law would find this distinction confusing. But because it is fundamental to an appreciation of the different roles of the Commission and reviewing courts, and because DTE has advanced this same argument in other proceedings, this PFD recommends that the Commission take the time and effort to clarify this important distinction. There is no legal presumption that findings of fact should be made in the utility's favor if there is conflicting evidence. If the Commission were to accept DTE's invitation to rule in the utility's favor whenever substantial evidence supports the utility's position, the Commission would not be performing the legally-required weighing and sifting of evidence and would be committing legal error.
>
> PFD, pp. 43; 44-45
>
> In its exceptions, DTE Electric took issue with the ALJ's analysis, contending that the PFD "is generally accurate in the abstract, but then the PFD misconstrues DTE Electric's position[.]" DTE Electric's exceptions, p. 2. DTE Electric explains:

> DTE Electric instead takes exception to the PFD's implicit presumption that the Company's requests for relief should be denied unless the Company overcomes some initial, unstated (and unlawful) hurdle of evidentiary weight. Instead, if DTE Electric supports its positions with substantial evidence, and there is no contrary evidence, then there is nothing for the Commission to weigh, and a decision by the Commission based on DTE Electric's evidence would satisfy the applicable standard of appellate review.

Id. (citations omitted). According to DTE Electric, the PFD exhibits a "pattern . . . of attempting to increase DTE Electric's evidentiary burden, and improperly recommending that DTE Electric's recovery should be denied or reduced because DTE Electric allegedly did not carry that inflated burden." *Id.*, pp. 2-3. DTE Electric specifically alleges that the PFD "suggests, for the first time, *and in the absence of contrary evidence or argument by a party,* that DTE Electric's evidentiary presentation is somehow insufficient based on questions or concerns that were not raised by the parties to the proceeding." *Id*., p. 3 (emphasis in the original). DTE Electric adds that it has overall concerns that there are recommendations in the PFD to adopt what it deems "other parties' conclusory suggestions (e.g., recommendations to default to any other suggestion on an issue, no matter how ill conceived, due to DTE Electric allegedly not carrying some heightened evidentiary burden)." *Id*., p. 3.

In their replies to exceptions, both the Staff and the Attorney General explain that DTE Electric is mistaken. According to the Staff:

> [I]t is incorrect to say that if the Company supports its position with substantial evidence, and no contrary evidence is submitted, then the Commission's hands are tied and it must approve the Company's request. Quasi-legislative decision-making is not so rigid, and the Commission may elevate its own regulatory judgement above that of any expert witness, so long as the Commission does not exceed its statutory authority or abuse its discretion. *In re Rovas Compl*, 482 Mich [90] at 100-101.
>
> Second, the Company misunderstands the ALJ's analysis. The ALJ is not imposing a higher burden. Rather, the ALJ is making a determination of: (a) whether the record contains substantial evidence to support a position sufficiently to allow the Commission to make a determination, and (b) whether the ALJ is persuaded that the Company's position is correct. Just because no other party challenges something the Company requests, does not mean that the ALJ may not ask her own questions, or raise her misgivings about

> a particular request. Not only may the ALJ do so, but the ALJ should do so, in every case.

Staff's replies to exceptions, p. 3.

Similarly, the Attorney General asserts:

> DTE argues that if it presents substantial evidence on the record to support an issue and there is no contrary evidence then the issue will survive on appellate review. . . . There are a number of problems with this argument. First, DTE bears the burden of proving that its rate increase request is prudent and reasonable – irrespective of what any other intervenor files in this case. As noted above, the MPSC may disbelieve even uncontradicted evidence. Second, DTE again conflates appellate review with the standard of evidence on which the Commission may rule. If DTE presents substantial evidence on an issue, that alone does not require the Commission to rule in DTE's favor. DTE must still demonstrate that the issue is reasonable and prudent and the trier of fact can disbelieve or not find credible the evidence put forward by DTE even without contrary evidence. Once the Commission determines that DTE presented substantial evidence on an issue and it is reasonable and prudent, then on appeal the substantial evidence test (competent, material, and substantial evidence) applies on the factual issue.

Attorney General's replies to exceptions, pp. 2-3.

The Commission finds that the ALJ's analysis is correct and that DTE Electric's misconceptions about the burden of proof and standards of review were thoroughly addressed by the PFD and the Staff's and Attorney General's replies to exceptions. Contrary to the claim in DTE Electric's exceptions, the ALJ accurately quoted and did not in any way "misconstrue" the company's statement that "[T]he applicable standard of proof for purposes of determining whether the Company's proposals or recommendations are reasonable and prudent is the 'substantial evidence' standard[.]" As was pointed out by the ALJ, the Attorney General, and the Staff, this is patently wrong. The fact that the company has presented "substantial evidence" (i.e., "more than a mere scintilla") on a particular proposal does not make the reasonableness and prudence of that proposal a forgone conclusion, as DTE Electric would have it, whether or not any other parties weigh in.[9]

[9] See January 31, 2017 order, pages 5-8.

Consistent with the law and the Commission's prior decisions, including the decision quoted above, this PFD applies a preponderance of the evidence standard in evaluating DTE's application. DTE's recitation of clearly wrong and previously rejected legal arguments also merits some additional censure from the Commission, as it serves only to distract the other parties, the ALJ, and the Commission from legitimate issues that must be resolved in a compressed schedule.

In its brief, DTE also argues that "the Commission has an obligation to facilitate DTE Electric's financial health for the benefit of its electric customers and shareholders."[10] In support of this statement, DTE cites *Smith v Illinois Bell Telephone Co*, 270 US 587, 591; 46 S Ct 408; 70 L Ed 747 (1926)*; Federal Power Comm v Hope Natural Gas Co*, 320 US 591, 602; 64 S Ct 281; 88 L Ed 333 (1944); *Michigan Bell Telephone Co v MPSC*, 332 Mich 7, 37 (1952); *Michigan Consolidated Gas Company v Public Service Comm*, 389 Mich 624, 633 (1973); *Michigan Bell Telephone Co v Engler*, 257 F3d 587, 594-96 (CA 6, 2001).[11] In her reply brief, the Attorney General also takes issue with DTE's assertion, characterizing it as a presumptuous statement:

> While it is well-established that a public utility is entitled to a reasonable return of and on its investments, the Commission's obligation is to facilitate an environment where that can happen. It is up to the Company to make sure that its business decisions are reasonable, prudent, and inure to the benefit of its customers and shareholders.[12]

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[10] See DTE brief, page 11.
[11] See DTE brief, page 11. That DTE has cut and pasted its argument from prior briefs is shown by its incorrect use of "supra" in its citation for two cases, *Federal Power Comm v Hope Natural Gas Co*, which had not previously been cited, and *Michigan Bell Telephone Co v MPSC*, which is not cited anywhere else in DTE's brief.
[12] See Attorney General reply, page 6.

As the Attorney General argues, the statutes and cases cited by DTE do not support its claim. Indeed, the key holdings from some of these cases highlight the Commission's obligation to balance shareholder and ratepayer interests and to provide only an opportunity for a utility to earn a reasonable return on its investment. For example, in *Federal Power Comm v Hope Natural Gas Co*, the Court addressed a challenge to a Federal Power Commission order reducing rates for Hope Natural Gas Co. The Court affirmed its earlier holding in *Federal Power Comm v Natural Gas Pipeline Co of America,*, 315 US 575, 62 S Ct 736; 86 L Ed 1037 (1942)*:*

> We held in *Federal Power Commission v. Natural Gas Pipeline Co . . .* that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' And when the Commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the Act. Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences.[13]

The Court then held, in oft quoted language:

> The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates

[13] Id., 320 US at 602.

> are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.

In *Federal Power Comm v Natural Gas Pipeline Co of America*, 315 US 575, 62 S Ct 736; 86 L Ed 1037 (1942), the United States Supreme Court addressed the applicable standards under the Natural Gas Act:

> By long standing usage in the field of rate regulation the 'lowest reasonable rate' is one which is not confiscatory in the constitutional sense. . .Assuming that there is a zone of reasonableness within which the Commission is free to fix a rate varying in amount and higher than a confiscatory rate . . . the Commission is also free under s 5(a) to decrease any rate which is not the 'lowest reasonable rate'. It follows that the Congressional standard prescribed by this statute coincides with that of the Constitution, and that the courts are without authority under the statute to set aside as too low any 'reasonable rate' adopted by the Commission which is consistent with constitutional requirements.[14]

In *Michigan Bell Telephone Co v MPSC*, the Court rejected the contention that the rate of return the Commission set was confiscatory. The Court cited *Federal Power Comm v Hope Natural Gas Co,* quoted above. The Court also cited *Bluefield Co v Public Service Comm*, 262 US 679, 692-293, for the standard:

> A public utility is entitled to such rates as will *permit* it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same

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[14] *Id*., 315 US at 585-586 (citations omitted).

> general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, *under efficient and economical management*, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[15]

It is unclear why DTE cited two other cases. In *Smith v Illinois Bell Telephone Co*, the Court was concerned that after holding hearings on a rate application in 1920, and again in 1922 following a court order, the Illinois commission had no intention of proceeding further with the case:

> It thus appears that, following the decree of the state court reversing the permanent order in respect of the second schedule and directing further proceedings, the commission for a period of two years remained practically dormant, and nothing in the circumstances suggests that it had any intention of going further with the matter. For this apparent neglect on the part of the commission, no reason or excuse has been given; and it is just to say that, without explanation, its conduct evinces an entire lack of that acute appreciation of justice which should characterize a tribunal charged with the delicate and important duty of regulating the rates of a public utility with fairness to its patrons, but with a hand quick to preserve it from confiscation. Property may be as effectively taken by long-continued and unreasonable delay in putting an end to confiscatory rates as by an express affirmance of them; and where, in that respect, such a state of facts is disclosed as we have here, the injured public service company is not required indefinitely to await a decision of the rate-making tribunal before applying to a federal court for equitable relief.[16]

In the *Michigan Consolidated Gas Company* case, the Michigan Supreme Court upheld a Circuit Court injunction granting the utility a rate increase above the rate increase granted by the Commission, providing that if the rate increase should ultimately be

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[15] Id., 332 Mich at 38 (emphasis added).
[16] *Id*., 270 US at 591-592.

disallowed, a refund would be made to the company's customers. Reviewing the provisions of MCL 462.26, the Michigan Supreme Court held that the judicial review provided for Commission decisions is in the nature of certiorari and does not contemplate the judiciary setting rates, but does permit equitable relief to prevent the confiscation of property. In *Michigan Bell Telephone Co v Engler*, the federal court addressed provisions of state law regulating telecommunications services, including a rate freeze and a statutory rate standard referred to as the "total service long run incremental cost" or TSLRIC. Nonetheless, the Court clearly recognized the standards of *Federal Power Comm v Hope Natural Gas Co*, quoted above:

> [T]he Ninth Circuit in *Guaranty National Insurance Co. v. Gates,* 916 F.2d 508 (1990), addressed the constitutionality of a Nevada insurance statute similar to MTA § 304(1) in its definition of an "inadequate" rate. Section 686B.050(3) of the Nevada Revised Statutes stated, "[r]ates are inadequate if they are clearly insufficient, together with the income from investments attributable to them, to sustain projected losses and expenses in the class of business of which they apply." *Id.* at 515. The Nevada statute essentially preserved insurance companies' ability to recoup the costs of their services. The Ninth Circuit held that although the Nevada statute guaranteed that insurers would "break even... it does not guarantee the constitutionally required 'fair and reasonable return.' " *Id.* (*citing Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591, 603, 64 S.Ct. 281, 88 L.Ed. 333 (1944) ("[T]he fixing of 'just and reasonable' rates, involves a balancing of the investor and consumer interests.... [T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include the service of the debt and the dividends on the stock")). Pursuant to the reasoning set forth in *Guaranty National, supra,* the MTA's definition of a "just and reasonable rate" does not guarantee the constitutionally-required fair and reasonable rate of return.

In upholding a preliminary injunction against this statute, the Court of Appeals determined that the statutory scheme at issue did not provide for any return. If DTE intends its reference to this case to mean that it is guaranteed a fair return, rather than the opportunity to earn a fair return, it is clearly misreading the case.

IV.

TEST YEAR

A test year is the starting point for establishing just and reasonable rates for both the regulated utility and its customers. The Commission has explained that the selection of an appropriate test year has two components:

> First, a decision must be made regarding a 12-month period to be used for setting the utility's rates. A second determination must then be made regarding how the Commission should establish values for the various revenue, expense, rate base, and capital structure components used in the rate-setting formula. The Commission may use different methods in establishing values for these components, provided that the end result is a determination of just and reasonable rates for the company and its customers.[17]

In developing its rates for this proceeding, DTE relied on a projected test year from May 1, 2020 through April 20, 2021, explaining that, in determining test year amounts, it began with the 2018 historical year, normalized and adjusted for known and measurable changes.[18] Several parties addressed DTE's reliance on a test year beginning 16 months after the historical period used as the starting point.

Only the RCG expressly recommended reliance exclusively on a historical test year. The RCG argues that the projected test year proposed by DTE extends beyond the projection period permitted by statute and is also unreasonable, arguing that an historical test year is the most accurate basis on which to set rates.[19] The RCG relies on the

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[17] See January 11, 2010 order, Case No. U-15678, page 9.
[18] See Crozier, 4 Tr 465.
[19] See RCG brief, pages 1-13.

testimony of Mr. Crandall, who considers DTE's projected test year outside the parameters of MCL 460.6a(1), and additionally expressed other concerns:

> DTE's requested reliance on its proposed projected test year unduly exaggerates the purported need for rate relief based on its forecasted revenue deficiency estimates. Using this approach, rates would not be based upon the available actual cost and revenue data including information for known capital expenditures, operation and maintenance expenses, and other cost and revenue elements included in the ratemaking formula. The Commission is required to issue Orders and process dockets within a 10-month time limit pursuant to Statute. Given these dynamics and the availability of actual cost and revenue data, the overall operational situation lends credence to the better approach being reliance by the Commission and DTE on a historical test year perspective (adjusted for known changes). This has the distinct benefit of providing a check upon whether or not the continual reliance on a projected test year perspective with its forecasted, estimated (best guesses/not actual) costs and revenues is merited. This would be an opportune time for the Commission to true up and modify the test period to reflect actual values. It is unnecessary to base DTE's electric customers rates repeatedly (case after case) on theoretical costs and revenues that comprise the projected test year perspective. The Commission has the authority and the duty to ensure that DTE's customer rates are just and reasonable and determining the appropriate test year perspective is an essential element of doing so.[20]

He recommended that the Commission use the historical test year projected revenue deficiency presented in DTE's Exhibit A-1, page 1 "with adjustments for known changes for purposes of setting rates in this proceeding."[21]

ABATE expressed significant concern with the level of rate increases it attributes to the use of projected test years to set rates, and recommended that the Commission review the use of projected test years in a generic proceeding, relying on Mr. Dauphinais's testimony.[22] Mr. Dauphinais reviewed DTE's historical and projected test year

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[20] 9 Tr 2813-2814.
[21] See 9 Tr 2815.
[22] See ABATE brief, pages 2-9.

calculations for this case and its three prior rate cases, presenting a chart comparing the revenue deficiency or sufficiency DTE calculated for the historical test year to its projected test year revenue deficiency to show the extent to which DTE's rate case revenue deficiency projections are driven by projected costs it has not yet incurred.[23] He testified that this has had adverse impacts on customers:

> First, it has caused and continues to cause customers to experience rate increases sooner than they would under the use of a historical test year.
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> Second, it has eliminated and continues to eliminate the incentive for DTE to contain costs that would otherwise exist due to the regulatory lag effect associated with the use of a historical test year.
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> Third, it has allowed and continues to allow DTE to fill its projections with proposed capital expenditures and expenses that either DTE has not irrevocably committed to making or otherwise can avoid if it finds it advantageous to do so to improve its realized rate of return for its shareholders. This can allow DTE to collect revenue from its customers for capital expenditures or expenses it does not ultimately incur or has not yet incurred when rates are placed into effect. This unreasonably benefits DTE's shareholders at the expense of DTE's customers to the extent the Commission Staff and intervenors are unable to uncover and bring to the Commission's attention such problematic projected costs before they are incorporated into DTE's base rates.
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> Fourth, use of a protected test year has allowed and continues to allow DTE to fill its projections with capital expenditures that are not truly necessary to provide reliable electric service at lowest reasonable cost. Once again, to the extent the Commission Staff and intervenors are unable to uncover and bring to the Commission's attention such problematic projected costs before they are incorporated into DTE's base rates, this provides a way for DTE to unreasonably increase the total return earned for its shareholders at the expense of its customers.
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> Finally, the use of a projected test year greatly handicaps the Commission Staff and intervenors in reviewing DTE's rate filings to ensure the projected capital expenditures and expenses are reasonable because they are not actual capital expenditures and expenses reflected on the DTE's books, but

[23] see 7 Tr 1742.

> rather projections developed over many separate cost subaccounts and revenue categories. This requires much more time and greater resources than are necessary in a rate proceeding that utilizes a historical test year all while the rate case timing has been compressed down to a ten-month time frame. As a result, while some inappropriate cost projections by DTE may be identified and successfully disallowed as a result of Commission Staff and intervenor review of DTE's projections, many other inappropriate cost projections may be missed and inappropriately included in DTE's rates at the expense of its customers as I have outlined above.[24]

Mr. Dauphinais expressly disagreed with DTE's characterization of its rate development as based on historical data "adjusted for known and measurable changes," providing examples.[25] He also presented a chart in his testimony and Exhibit AB-2 to show that DTE has "more often than not" over the last five years been able to earn a return in excess of that which is authorized.[26]

Mr. Dauphinais recommended that the Commission "continue to be vigilant with respect to ensuring the expenses and investments being projected by DTE for its projected test year are truly expenses and investments that are necessary to provide reliable electric service at lowest reasonable cost," "ensure that DTE is irrevocably committed to incur them or otherwise cannot avoid them," and "ensure that these projected investments and expenses are precisely quantified by DTE with respect to both amount and the specific quarter in which DTE will incur these investments and expenses."[27] Mr. Dauphinais also recommended that the Commission initiate a generic proceeding to review experience to date in Michigan with the utilities' use of projected test years:

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[24] See 7 Tr 1643-1644.
[25] See 7 Tr 1644-1645.
[26] See 7 Tr 1646-1647.
[27] See 7 Tr 1649-1650.

> This should include consideration of both the benefits and detriments to customers that have resulted from the use of a projected test year by Michigan utilities. It should also examine such issues as: (i) the conditions under which the Commission would reject the use of a projected test year; (ii) the types of projected costs and investments that should be excluded from a projected test year; (iii) the minimum criteria that needs to be met to reasonably demonstrate that the utility is sufficiently committed to actually incur the projected expense or investment; (iv) the length of time allowed between the end of the utility's historical test year and the beginning of the utility's proposed projected test year; and (v) whether the use of a projected test year should be a factor in determining the authorized return on equity of a utility.[28]

In her brief, the Attorney General agreed with ABATE's recommendations.[29] Citing Mr. Dauphinais's testimony, the Attorney General argued that DTE and other utilities have disproportionately benefitted from the use of the projected test year. The Attorney General also cited the period of time over which projections are made in each rate case:

> For example, in the instant case, DTE Electric historical test year ended December 31, 2018, and the Company proposed a future test year beginning on May 1, 2020 and ending April 30, 2021. As a result of the extended forecasted test year, the Company also forecasted capital expenditures for the period from January 1, 2019 to April 30, 2020. Therefore, in total the rate case required 28 months of projected capital expenditures from January 1, 2019 to April 2021. The problem with long forecasted period is not limited to capital expenditures. It is also more difficult and less accurate to project revenues and operations and maintenance expenses that will occur nearly two years down the road.[30]

In his testimony, Mr. Coppola noted that DTE's filing projects $4.6 billion in capital expenditures from January 2019 through April 2021. He reviewed the increase in DTE capital expenditures in recent years relative to prior years, characterizing it as dramatic, with charts showing annual capital expenditures and rate base growth from 2009

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[28] See 7 Tr 1650.
[29] See Attorney General brief, pages 23-25.
[30] See Attorney General brief, pages 24-25.

forward.[31] In her brief, the Attorney General offers the following list of items that could be considered in a generic proceeding:

> 1. The conditions under which the Commission would reject the use of a projected test year;
>
> 2. The types of projected costs and investments that should be excluded from a projected test year;
>
> 3. The minimum criteria that needs to be met to reasonably demonstrate that the utility will actually incur the projected expense or investment;
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> 4. The length of time allowed between the end of the utility's historical test year and the beginning of the utility's proposed projected test year with the objective of shortening this "bridge period" to less than six months; and
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> 5. How the use of a projected test year reduces regulatory risk and should be included as a factor in determining the authorized return on equity of a utility.[32]

In its reply brief, Soulardarity agreed with ABATE's and the Attorney General's recommendation.[33] Soulardarity expresses a concern that rates that cover earnings above and beyond the return on equity authorized by the Commission particularly harms low-income customers. Further, Soulardairty endorses Mr. Dauphinais's concern with the length of the projection period, arguing that the 28-month projection period in this case, from the December 31, 2018 end of the historical test year to the April 30, 2021 end of the projected test year, lends itself to inaccuracies and problems. It concludes: "The AG's proposed review process would lend itself to a better balancing between the interests of DTE and the ensuring benefits and detriments to customers, particularly

[31] See 9 Tr 2964-2966.
[32] See Attorney General brief, page 25.
[33] See Soulardarity reply, pages 15-17.

vulnerable low-income customers whose unique interests might otherwise be overlooked or disregarded."[34]

Walmart argues that the utility's use of a future test year with a projected rate base is a factor to be considered in evaluating the return on equity to authorize in this case.[35] Mr. Chriss cited the Commission's October 20, 2011 order in Case No. U-16472 as recognizing this as a factor to be considered.[36]

Ms. Crozier addressed only Mr. Crandall's recommendation in her rebuttal testimony, citing prior Commission approval of the company's current test year methodology and characterizing Mr. Crandall's recommendation as illogical since rates are set for a future twelve-month period.[37] In its brief, DTE also argues that the RCG's proposal violates fundamental due process.[38] Although not addressing the testimony of Mr. Dauphinais in its brief, DTE argues in its reply brief that the Commission has no alternatives to consider in a generic proceeding:

> There would only be two possible results from such a proceeding: (1) the Commission could decide to follow the law, as it has done and it is required to do, or (2) the Commission could decide to stop following the law, which would be illegal and reversible on appeal - perhaps by the utility industry as a whole. Either way, the proceeding would be a waste of valuable time and scarce resources for the Commission and all other parties involved.[39]

DTE also argues that its use of a projected test year is already considered in setting its authorized return on equity.

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[34] See Soulardarity brief, pages 16-17.
[35] See Walmart brief, page 10; 9 Tr 2663.
[36] See 9 Tr 2667.
[37] See 4 Tr 504.
[38] See DTE brief, pages 12-13.
[39] See DTE reply, page 8.

In its May 2, 2019 order in Case No. U-20162, the Commission rejected the RCG's legal analysis:

> MCL 460.6a(1) provides that "A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges." The statute contains no limitation on the future consecutive 12-month period and no requirement to use an historical test year. The test year may be in the future, and the 12 months must be consecutive; those are the requirements of the statute. RCG offers no evidence whatsoever to demonstrate any relationship between the date of the rate case filing and the test year used by the applicant and the Commission can find none in the language of MCL 460.6a(1). In this case, the test year commenced one day before the issuance of this order and five days before the statutory deadline. MCL 460.6a(5). The Commission finds that the proposed test year complies with the requirements of MCL 460.6a(1) and should be adopted.[40]

Based on the Commission's analysis and conclusion, this PFD finds that DTE's projected test year complies with the requirements of MCL 460.6a(1) governing the choice of test year.

Turning to the recommendations that the Commission conduct a generic proceeding to evaluate the use of projected test years in utility ratemaking, the ALJ finds merit in the parties' concerns as documented in Mr. Dauphinais's testimony. In unrebutted testimony, he did establish that DTE's revenue requirements calculations are in large part driven by projected expenses that have not yet been incurred. Additionally, as the review of the disputed cost items in subsequent sections of this PFD shows, DTE has departed from the "known and measurable" standard it purports to adopt, has frequently failed to provide supporting evidence for its projections, has failed to undertake certain analyses called for by the Commission, and has attempted to provide additional

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[40] See May 2, 2019 order, Case No. U-20162, page 4.

support for disputed cost elements in its rebuttal filing. Additionally, DTE views its established rates, including projected rate base items for specific capital projects, as a budget within which it is free to "reprioritize" in part to protect its earnings level.

To put some additional context to Mr. Dauphinais's concern that costs cannot be adequately reviewed, the filing itself presents informative statistics. DTE's 2018 capital expenditures, which could not have been audited in the last rate case, totaled $1.7 billion as shown in Exhibit A-12, Schedule B5; additional projected capital expenditures through the end of the test year total $4.6 billion, for a total of $6.3 billion. Together, these capital expenditures in theory subject to review in this case, constitute approximately 1/3 of DTE's total projected rate base. Another way to view the filing, the enumerated projects for DTE's non-nuclear generation capital expense (which excludes projects under $1 million) total 151 as shown in Schedule B5.1 of Exhibit A-12; for its distribution system, DTE's filing enumerates 143 projections over the same time period as shown in Schedule B5.4, pages 5, 7, 8, and 9; and the listed IT projects in Schedules B.5.7.1 through B.5.7.8 that include spending from January 2019 through the end of the projected test year total 138, and exclude projects expected to cost less than $250,000 each. These projects alone total 432. The current rate case schedules provide 120 days from the date of filing for the parties to review DTE's application, including its 2018 capital spending and projected capital costs, as well as the myriad other elements including the cost of capital, sales projections, O&M spending, pilot projects, cost allocations, rate design, and proposed changes to the terms and conditions of service. Looking at the capital costs alone, that is approximately $52 million per day including 2018 capital expenditures, $38 million of projected spending per day, or 3.6 projects per day.

A recommendation that the Commission initiate a generic proceeding is clearly addressed to the Commission's discretion. As Mr. Dauphinais testified, a generic proceeding may provide the Commission with the opportunity to further articulate filing requirements and expectations that projected test year funding will be spent as projected. Nonetheless, it is unclear to this ALJ what a generic proceeding could accomplish to help the Commission, its Staff, and the parties reasonably evaluate the company's cost projections within the statutory timeframe that the Commission is unable to accomplish through rate case proceedings.

In order to address concerns of the nature raised by Mr. Dauphinais, in the series of rate cases following the enactment of 2008 PA 296, the Commission has acknowledged that it is not obligated to accept utility "projections," and has further insisted that utilities bear the burden to establish the reasonableness of their projections. In the first rate case for DTE following the enactment of 2008 PA 286, the Commission made clear that where a utility decides to base its filing on a fully projected test year, it bears the burden to substantiate its projections:

> As the Commission discussed in its November 2, 2009 order in Case No. U-15645, p. 8, Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility "may use projected costs and revenues for a future consecutive 12-month period" to develop its requested rates and charges. The Commission added that the Staff and intervenors should direct their focus "upon the strengths and weaknesses of the evidentiary presentations of the parties regarding specific expense and revenue projections." 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.[41]

[41] See January 11, 2010 order, Case No. U-15678, page 9.

The Commission further explained:

> 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.[42]

In that case, the Commission also distinguished DTE's (then Detroit Edison's) approach to the test year, recognizing its reliance on a "known and measurable" approach in contrast to a "fully projected test year" approach:

> In developing its projections, Detroit Edison opted not to use a fully projected test year and instead used actual financial results from the 12 months ending June 30, 2008 and then normalized and adjusted those results for inflation and other known and measurable changes to arrive at its projected electric revenue deficiency for the test year ending June 30, 2010.[43]

DTE purports to use the same method in this case, but as noted above and as Mr. Dauphinais explained, its adjustments to historical test year data are not strictly "known and measurable."

In subsequent orders, the Commission has further articulated its expectations for test year projections. The Commission has repeatedly rejected the contention that it is obligated to accept projections. In Case No. U-18014, the Commission held:

> In a related concern, DTE Electric repeatedly asserts that the ALJ's rejection of the company's position on certain costs violates MCL 460.6a(1), which provides that "A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and

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[42] See January 11, 2010 order, Case No. U-15678, pages 9-10.
[43] See January 11, 2010 order, Case No. U-15678, page 10.

charges." According to DTE Electric, any failure to approve costs projected by the company not only violates Section 6a(1) but also invades the company's constitutionally protected right against takings. The Commission has rejected this argument in the past:

> 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 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.

June 12, 2012 order in Case No. U-16794, p. 13.

Moreover, in the case where the company seeks approval for a projected cost, the company must not only provide sufficient evidence to demonstrate to the Commission that both the specific project and its cost are reasonable and prudent, but it must also show by a preponderance of the evidence that the cost will in fact be incurred before the end of the test period.[44]

In that same order, the Commission made clear that DTE may not include amounts in its projections as a "placeholder," waiting to decide how the money will be spent or justification for the expenditure until rebuttal. Citing its holding in Case No. U-15768, quoted above, the Commission stated: "The Commission agrees with the ALJ that

[44] See January 31, 2017 order, pages 8-9.

including "placeholder" amounts in the company's initial filing, and then attempting to justify these amounts later is unreasonable."[45]

This rate case provides the Commission with the opportunity to enforce its earlier pronouncements and provide further direction to DTE. Of course, as Walmart and ABATE argue and as DTE concedes,[46] the Commission may consider the utility's ability to use a projected test year, without regulatory lag between the test years used from rate case to rate case, in determining DTE's authorized return on equity. A generic proceeding, even if commenced at the same time as the Commission's order in this docket, would not be completed before the expected date of DTE's next rate case, if it continues its established pattern of filings within a couple of months of its most recent rate case order, and may not be completed before the rate case it files after that one. Additionally, the ALJ notes that the Commission has broad authority to investigate utility costs and management decisions outside the context of a rate case.

V.

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 projected a total electric rate base of approximately $18.25 billion, which it revised to $18.17 billion in its initial brief. In its direct case, Staff recommended a $131 million reduction to DTE's filed rate base, which it revised to a $127 million reduction in

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[45] See January 31, 2017 order, page 30.
[46] See DTE reply, page 8.

its initial brief. The Attorney General recommended a $421 million reduction to rate base. ABATE recommended a $105 million reduction to rate base. Although not computing a revised rate base, the MEC Coalition recommended adjustments to DTE's projected rate base value.[47] The ELPC Group and Soulardarity also expressed concerns with elements of DTE's projected capital spending, without recommending reductions in rate base projections. In addition to its recommendation that the Commission use historical rate base values, as discussed above, the RCG supported Staff's recommendations regarding certain rate base elements.

In the discussion that follows, disputes regarding DTE's projected net plant are discussed in section A, and disputes regarding DTE's projected working capital are discussed in section B, with a summary in section C.

A. <u>Net Plant</u>

Net plant is the primary component of rate base, and its key elements are total utility plant – plant in service, plant held for future use, and construction work in progress (CWIP) – less the depreciation reserve, which includes accumulated depreciation, amortization and depletion. In evaluating the arguments of the parties, the ALJ takes note of the standards the Commission has articulated, as discussed in section IV above.

1. Contingency

Although the Commission has repeatedly rejected DTE's inclusion of contingency amounts in projected capital spending, DTE included $17.7 million in contingency

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[47] And, as noted above in section III, the RCG recommended that the Commission use DTE's historical 2018 rate base value of $16,323,401 as stated in Exhibit A-1, Schedule A1.

amounts in its capital expense projections in this case. Staff witness DeCooman, Attorney General witness Coppola, and ABATE witness York recommended that the contingency amounts be excluded from projected plant balances consistent with prior Commission orders. In its initial brief, DTE agreed to reduce its projected net plant and rate base to exclude the $17.7 million contingency amounts. There is thus no dispute that the projected contingency expenses should be removed.

2. Capitalized Incentive Compensation Costs

As with contingency amounts, the Commission has been consistent in recent DTE rate cases, as well as in rate cases for other utilities, that incentive compensation payments DTE makes to employees for meeting financial targets are not a recoverable expense. In his testimony and Exhibit AG-1.40, Mr. Coppola explained that nonetheless, DTE has been including such incentive compensation payments when it capitalizes labor costs. He identified a total of $44.4 million of such costs included in or projected to be included in rate base from 2018 through 2021.[48] The Attorney General recommends that the Commission adopt Mr. Coppola's adjustment.[49]

Ms. Crozier provided rebuttal testimony for DTE opposing Mr. Coppola's proposed reduction.[50] She disputed that the Commission had excluded these amounts from rate base, contending the Commission had only excluded these amounts from O&M. She testified: "Mr. Coppola's recommendation should be rejected because it is a significant departure from past rate-making treatment and will result in a plant balance that does not

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[48] See 9 Tr 3072-3073.
[49] See Attorney General brief, pages 58-61.
[50] See 4 Tr 504-505.

reflect the full cost incurred by DTE."[51] She also requested that any change to DTE's capitalization of these costs be made prospective only, on the date rates become effective following a Commission order in this case: "The use of that effective date will also avoid a significant write off related to costs that had previously been incurred and approved for inclusion in rates as reasonable and prudent by the Commission."[52]

In its brief and reply brief, DTE reiterates Ms. Crozier's rebuttal testimony.[53] DTE also continues to argue that it should recover incentive compensation associated with financial measures, as discussed below in section VII (Adjusted Net Operating Income). The Attorney General addressed Ms. Crozier's rebuttal testimony in her brief, citing cross-examination of Ms. Crosier at 4 Tr 509-514, and arguing that Ms. Crozier has no training or experience in regulatory accounting, and did not know whether DTE disclosed in Case No. U-20162 that it was including incentive compensation in rate base.[54]

This PFD finds no merit in DTE's claim that it was entitled to treat incentive compensation for financial measures as a recoverable capital cost, and recommends that the adjustment proposed by the Attorney General be adopted. Neither Ms. Crozier in her rebuttal nor DTE in its briefs disputed the figures in Exhibit AG-1.40, which DTE provided. Staff's brief cataloged the numerous cases in which the Commission has refused to allow DTE to recover incentive compensation expenses associated with financial measures. DTE has cited nothing to show the Commission affirmatively approved this alternative method for it to recover disallowed incentive compensation expenses.

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[51] See 5 Tr 505.
[52] See 4 Tr 505.
[53] See DTE brief, page 151; see DTE reply brief, page 88.
[54] See Attorney General brief, pages 60-61.

Mr. Coppola's Exhibit AG-1.40 shows that for 2018, DTE capitalized short term and long-term incentive compensation attributable to financial measures despite the Commission's orders. DTE's 2019 – 2021 capital expense projections also include long term and short-term incentive compensation amounts as shown on that exhibit. Also troubling, it appears DTE excepted O&M expense recovery of approximately $20 million for target-level performance associated with non-financial measures under the short-term incentive plans and then capitalized a significant portion of these expenses to rate base, approximately $5.1 million as estimated by Mr. Coppola.[55] Looking at the total O&M expense and expense capitalizations reported on page 2 of Exhibit AG-1.40, DTE's 2018 O&M expense includes an approximately $29 million expense for target-level performance for all measures under the short term incentive compensation plans, and additionally includes capitalized expenses of approximately $12 million also for target level performance, a total well above DTE's total target-level payout of approximately $29 million for all measures under its short term incentive plans as shown at 5 Tr 938. DTE's projected test year O&M expense includes incentive compensation expense of $30.8 million for target-level performance on all measures, which matches the amount shown in Mr. Cooper's chart at 5 Tr 938, plus an additional amount of $12.8 million capitalized to rate base, which is clearly duplicative of the O&M expense level.[56] Similarly, for long-term incentive compensation, DTE's test year O&M expense projections include long-term incentive compensation of $20.5 million (equivalent to the amount shown at 5 Tr 938

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[55] See Exhibit AG-1.40, page 2.
[56] See Exhibit A-1.40, page 4.

prior to Mr. Cooper's correction) and an additional $5.7 million capitalized to rate base.[57] Mr. Cooper's testimony shows that the projected expenditures in his chart at 5 Tr 938 were intended to reflect the total company incentive compensation plan, not merely a part of it. The total expense levels shown there are the same levels he purported to justify with a benefit cost analysis in Exhibit A-21, Schedule K8.

For these reasons, this PFD finds as a first step the Commission should adopt Mr. Coppola's recommended adjustments to rate base. Second, in view of the information in Exhibit AG-1.40, the Commission should direct DTE to immediately provide the Commission with a report in this docket identifying the amount of incentive compensation attributable to financial measures DTE has included in rate base at least over the last five years, and direct DTE to clearly exclude such amounts from rate base in its next rate application. The Commission may also want to initiate an investigation to determine what faulty managerial or other decision-making process led DTE to flagrantly ignore the Commission's numerous decisions on this expense category. Third, the Commission should also insist that DTE explain the apparent double-recovery of allowed incentive compensation costs through its capitalization of expenses funded through O&M in rates.

DTE's arguments that it should be allowed to recover projected test year incentive compensation expenses are discussed in section VII below.

3. Production Plant (Exhibit A-12, Schedule B5, lines 2-4; Schedule B5.1)

As shown in Schedule B5.1 of Exhibit A-12, lines 2-4, DTE projects capital spending for its steam, hydro, and other non-nuclear production plant of $993 million for

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[57] See Exhibit AG-1.40, page 5.

the "bridge" period from January 1, 2019 through the May 1, 2020 start of the projected test year, and $520 million during the test year. Mr. Morren provided the principal testimony in support of DTE's projections, with additional testimony from Ms. Leslie and Mr. Burgdorf. The MEC Coalition, Attorney General, and ABATE took issue with elements of DTE's projected expenses.

In the discussion that follows, capital funding for River Rouge unit 3 is addressed in section a, and the Attorney General and ABATE arguments regarding other routine and non-routine capital expense projections are addressed in sections b and c. The MEC Coalition's request that the Commission require DTE to provide a more detailed accounting for its Coal Combustion Residual (CCR) costs is addressed in section d, and its request that the Commission require DTE to undertake additional analyses of the retirement date for the Belle River plant is addressed in section e.

a. River Rouge Unit 3 Past and Projected Capital Expenditures

The issue of the retirement of River Rouge unit 3 has been a recurring subject of the Commission's rate case orders. In its May 2, 2019 order in Case No. U-20162, the Commission summarized the history of its decisions to that date:

> In the December 11, 2015 order in Case No. U-17767, p. 14, the Commission disallowed capital costs associated with environmental retrofits for Unit 3 because they were not shown to be cost effective. In the January 31, 2017 order in Case No. U-18014, p. 17, the Commission again disallowed capital costs for Unit 3. In that order, the Commission found that the utility had decided to permanently shut down River Rouge Unit 2 but had not updated any of the assumptions in the NPVRR for Unit 3, despite knowing that Units 2 and 3 shared many costs; thus, again failing to show that the capital expenditure was cost effective (the Commission allowed O&M costs). In the 2018 orders, the Commission again disallowed capital costs for Unit 3 based on the continued failure of the utility to update the NPVRR and its entire analysis of Unit 3 with a showing of clear cost

effectiveness, but allowed O&M costs. April 2018 order, p. 8, and June 2018 order, p. 5.

After evaluating DTE's argument that it should be allowed to include the previously -disallowed capital costs and additional projected capital costs through the test year in that case, as well as O&M costs, based on DTE's analysis that the unit should not retire until May 2020, the Commission rejected the utility's request:

> The Commission sees no reason on this record to deviate from its prior determinations. The Commission continues to agree with DTE Electric that while the unit is in use, reasonable and prudent O&M costs should be approved to ensure safe operation and a smooth transition to retirement. However, the updated NPVRR provided on this record does not persuade the Commission to award the 2017-2018 capital costs to DTE Electric nor the future capital expense, because the evidence is simply not conclusive on the issue of reasonableness and prudence. The NPVRR does not make a convincing case that the 2017-2018 capital expense amounts were prudent in comparison to shutting Unit 3 down in 2016, nor does it make a convincing case that the bridge period and test year amounts make sense in comparison to shutting the unit down earlier than 2020. The company made a decision to continue to run Unit 3 and the unit must be run safely and in compliance with all applicable environmental laws; thus, the Commission has continued to approve O&M costs. But the decision to make capital investments in Unit 3 has not been adequately supported from the beginning. The Commission denies the requested $8.45 million in past capital expense and $1.87 million in future capital expense, and approves $17.65 million in O&M costs.[58]

Citing its February 2019 decision to retire St. Clair unit 1, DTE now proposes that it will operate River Rouge unit 3 until 2022, using a combination of industrial gas and natural gas.[59] In support of its plan, DTE presented the testimony of Mr. Morren, Ms. Leslie, and Mr. Burgdorf. DTE argued that its economic analysis justifies its plan as

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[58] See order, pages 11-12.
[59] See DTE brief, pages 19-22, 28-32; DTE reply brief, pages 18-24.

beneficial to ratepayers, and that additional factors including grid reliability and local community and environmental benefits also weigh in favor of the program.

The MEC Coalition objected to DTE's proposal.[60] MEC argued that DTE's economic analysis suffers from multiple flaws that when corrected, shows that fully retiring the plant May 2020 would be the lower cost option for ratepayers. MEC further disputed DTE's contention that grid reliability, local community interests, and environmental factors justify the continued operation of the plant.

As the testimony in this case reflects, DTE's request was also presented as part of its Integrated Resource Plan (IRP) in Case No. U-20471, on basically the same record. In its February 20, 2020 order in Case No. U-20471, the Commission agreed that a decision on this matter should be left to the rate case.

For the reasons discussed below, this PFD finds DTE has not supported its plan to extend the retirement date of unit 3 and MEC's recommendation to exclude from rate base those capital costs associated with extending operations beyond May 2020 should be adopted. In the discussion that follows, DTE's economic analysis and Dr. Lentedre's critique are discussed in section i), followed by a discussion of grid reliability, environmental factors, and community impact in sections ii) through iv).

i. Economics

Ms. Leslie presented a net present value revenue requirement (NPVRR) analysis for River Rouge unit 3 to compare the economics of a 2020 versus 2022 retirement for the unit. She obtained a range of results for the analysis based on four different capacity

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[60] See MEC brief, pages 5-37.

price assumptions or “sensitivities.” A comparison of the NPVRR results for each of the capacity price “sensitivities” is in Schedule B6.2 of Exhibit A-12. She characterized these results as follows:

> The results of the NPVRR analysis of operating RR3 on recycled industrial and natural gases until May 2022 show a range from $14 million in favor of continuing to operate the plant through May 2022 to $1 million in favor of retiring the unit in May 2020.[61]

Dr. Letendre took issue with the assumptions underlying Ms. Leslie’s analysis. He critiqued the capacity price assumptions and the fuel cost forecasts used in the analysis, identified errors in DTE’s capital and O&M cost assumptions, and testified that DTE had not included the previously-disallowed $10.3 million of capital expenditures for River Rouge unit 3 in its analysis. DTE provided rebuttal testimony addressing the assumptions underlying its analysis. The points of dispute are discussed in subsections a through e below.

a. capital and O&M cost assumptions

Citing testimony from DTE’s IRP case, Dr. Letendre testified that DTE omitted two years of post-retirement O&M costs from its modeling of the 2022 retirement scenario in this case, and also omitted capital costs required to reroute water streams for operations after October 2020.[62] The omitted O&M costs total $1.5 million per year, while DTE provided an estimate of under $1 million for the water routing. In her rebuttal testimony, Ms. Leslie acknowledged that DTE had not included these costs in its analysis. Regarding the capital costs, she testified that the costs were not known at the time of

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[61] See 5 Tr 792.
[62] See 9 Tr 3765.

DTE's NPVRR analysis, and further, that DTE is in the process of designing this rerouting project.[63]

Dr. Letendre testified that the omitted costs add $2.39 million in present value to the NPVRR results for the 2022 retirement.

b. fuel assumptions

DTE plans to operate the unit using 20% natural gas, 50% coke oven gas (COG), and 30% blast furnace gas (BFG), and based its analysis on the assumption that the industrial gas fuels will cost 30% of the cost of natural gas. Dr. Letendre objected to DTE's assumption that it could obtain industrial gas at 30% of the cost of natural gas, noting DTE's acknowledgment that it does not have contracts in place for industrial gas during that timeframe.[64] Citing confidential Exhibit MEC-44, he testified that the company did not forecast fuel cost but instead determined the fuel cost price point that would make the utility's plan appear economic:

> DTE modeled industrial gas at the price the Company contends it would need in order to ensure that operations of the unit provide economic value to customers. In other words, DTE modeled the price it needs for the unit to make money, not the price it actually has a contract for. We have no information on whether that price is high enough to cover delivery and handling costs and make it profitable for the current industrial suppliers to continue providing the gas to DTE. Additionally, there is no guarantee that the current industrial gas suppliers will agree to the assumed price or will not find an alternative use for the gas or buyer willing to pay a higher price.[65]

He testified that DTE's cost for industrial gas has historically been 40-50% of the price of natural gas,[66] and noted that currently-low gas prices have been volatile historically. Dr.

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[63] See 5 Tr 776.
[64] See 9 Tr 3768-3769, Exhibits MEC-44 and MEC-45.
[65] See 9 Tr 3769.
[66] See 9 Tr 3769, also citing to the record in Case No. U-20471.

Letendre also questioned DTE's assumption that a significantly higher volume of industrial gas would be available for the plant. Dr. Letendre also objected that DTE had not modeled any price sensitivities around its assumed fuel prices.[67]

Mr. Morren testified in rebuttal in defense of DTE's price claims:

> Witness Letendre made an inappropriate deviation from the Company's analysis by assuming the Company will continue to pay historic price levels for industrial gases even though the Company has indicated the contract requires renegotiation. The Company is forecasting a reduced price for industrial gases, as included in the Company's NPVRR analysis.[68]

He also testified that DTE is currently in negotiations with the supplier "and expects pricing similar to what was modeled in the Company's NPVRR analysis in this case."[69] Ms. Leslie echoed Mr. Morren's testimony.[70] In cross-examination, Mr. Morren acknowledged that DTE's fuel cost estimate was based on the cost it determined would be necessary to make the economics of continuing to operate the plant positive.[71]

At the end of the hearing, MEC introduced Exhibit MEC-130 to show that U.S. Steel, DTE's source of industrial gas via its affiliate, would be curtailing production. In this discovery response, while asserting that the closures will "not impact DTE Electric's current plan to cease burning coal at River Rouge Unit 3 in May of 2020," DTE acknowledged: "DTE Electric has not determined how this development affects the plan to power the unit solely on recycled industrial gases and natural gas after May 2020." Despite that acknowledgement, DTE disputed that U.S. Steel's announcement as

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[67] See 9 Tr 3771.
[68] See 5 Tr 658.
[69] See 5 Tr 659.
[70] See 5 Tr 777.
[71] See Morren, 7 Tr 700.

reflected in exhibit MEC-130 casts doubt on the utility's plans to acquire industrial gasses to operate the unit:

> First, the U.S. Steel announcement has nothing to do with the reasonableness and prudence of DTE Electric's prior expenditures of $10.3 million in necessary maintenance capital expenditures to continue to operate River Rouge Unit 3 safely and in compliance with environmental regulations. Those expenditures were simply necessary to run the plant in the intervening period prior to retirement – which was and is a reasonable and prudent thing to do for the reasons explained throughout this section. Furthermore, the U.S. Steel announcement primarily affects the potential supply of blast furnace gas, which represents the smallest portion of recycled industrial gas anticipated to be consumed on River Rouge Unit 3.[72]

DTE cited Exhibit MEC-46 in support of this contention, which shows the quantities of each fuel type DTE expected to use. In its reply brief, citing Exhibit MEC-44, the MEC Coalition argued that DTE does depend on U.S. Steel for both types of industrial gas:

> DTE's proposal to continue operating River Rouge 3 past May 2020 was based on the assumption that blast furnace gas ("BFG") and coke oven gas ("COG") would provide the vast majority of the unit's fuel. These industrial waste gases were to be provided, either directly (for BFG) or indirectly (for COG), by the nearby U.S. Steel facilities. U.S. Steel's December 2019 announcement that it will indefinitely idle operations at these facilities thus undercuts a central premise of DTE's proposal. Because there is too much uncertainty regarding DTE's plan to continue operating River Rouge 3 past May 2020, the Commission should not approve rate recovery of any capital or O&M expenditures associated with that plan.[73]

c. capacity price assumptions

DTE's analysis included a range of capacity price assumptions for replacement capacity for River Rouge from May 2020 through May 2022 ranging from $0 to $88.80

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[72] See DTE reply, page 19.
[73] See MEC reply, page 7; MEC argues that the coke oven gas supplier is also dependent on U.S. Steel indirectly, citing the "whereas" clauses in the contract beginning on page 26 of Exhibit MEC-44, as well as information included in the contract beginning on page 6 of Exhibit MEC-44. Also see Exhibit MEC-44, page 5.

per kW-year. Included in this range, in addition to the zero value, DTE used the Cost of New Entry (CONE), 50% of CONE, and a November 2018 PACE forecast as shown in Schedule B6.2 of Exhibit A-12.[74] Other than the zero value, the lowest capacity price forecast DTE used in its analysis was the 50% CONE value of $44.40 per kW-year.

Dr. Letendre testified that the non-zero values in DTE's analysis were overstated, and recommended that DTE should have included lower capacity price forecasts for more realistic modeling:

> Two of the prices are based on the Cost of New Entry (CONE) set by MISO for planning year 2019/2020, one was based on a forecast developed by PACE, and the last one tested a $0 capacity price. All of these prices, with the exception of the $0 sensitivity, represent the high end of potential capacity prices.[75]

Dr. Letendre first explained that the PACE forecast compares the peak capacity forecast for Zone 7 to the forecast local clearing requirement (LCR) plus a 150 MW buffer. If the peak capacity exceeds the LCR plus the buffer, the PACE forecast assigns the zone the same forecast as the rest of MISO. But if the peak capacity is less than the LCR plus the buffer, PACE calculates a zone-specific price that approaches the net cost of new entry (NET CONE, or the operating margin that a new resource would need to earn in the capacity market after netting out energy and ancillary service revenues) for a combustion turbine as the regional reserve margin is reached.

Dr. Letendre objected to reliance on the PACE model forecast because it assumes that there are insufficient local capacity resources available within Zone 7 between 2019

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[74] See 5 Tr 762.
[75] See 9 Tr 3752.

and 2023. As a result of this assumption, he testified that the PACE capacity cost forecast increases from $3.18 per kW-year in 2018 to over $50 per kW-year from 2019 through 2023.[76] Dr. Letendre provided several reasons why he rejected this result, testifying that the PACE forecast does not consider MISO market power mitigation considerations, incorrectly models the Capacity Import Limit (CIL) for Zone 7 and thus overstates the LCR, and is out of date and was updated in a biased manner.

Specifically addressing the treatment of CIL in the PACE forecast, Dr. Letendre explained that the PACE model calculates the Local Clearing Requirement by subtracting CIL from the Local Reliability Requirement: "A higher CIL reduces the LCR and allows more of the Zone's capacity needs to be met by resource outside the Zone. A higher CIL also makes it more likely that Zone 7 will have excess local capacity above the amount required by the LCR, which in turn will make Zone 7 less likely to diverge from the MISO-wide capacity price."[77] Referencing testimony in Case No. U-20471, he explained that the PACE forecast mixes Local Reliability Requirements (LRR) in units of installed capacity (ICAP) with a CIL that is calculated relative to units of unforced capacity (UCAP), which is ICAP minus the forced outage rate.[78]

Dr. Letendre testified that if the deficiencies he identified in the PACE model are corrected and updated for the 2020-2021 Loss of Load Expectation (LOLE) Study report, Exhibit MEC-42, then the peak capacity forecast for Zone 7 would be above the LCR plus

[76] See 9 Tr 3754.
[77] See 9 Tr 3756.
[78] See 9 Tr 3756-3757. Put another way, because the LCR = LRR – CIL, and MISO measures both LCR and LRR in UCAP units, to mix CIL with LCR and LRR values measured in ICAP units is improper.

150 MW cushion, and the PACE prediction for Zone 7 would equal the MISO-wide forecast of $1.50 per kW-year.[79] He testified:

> DTE did not include a sensitivity that set the capacity price for Zone 7 at the MISO wide capacity price of $1.50 per kW-year. Given how sensitive the model is to a small change in capacity, and how large an impact these changes have on the final capacity price, and the level of uncertainty, it is surprising that DTE did not consider this an important price sensitivity to include or discuss. This omission is especially concerning given that this sensitivity represents a reasonably possible future outcome for Zone 7's capacity price.[80]

Dr. Letendre also discussed the capacity price forecast included in DTE's most recent PSCR plan filing, which assumes that the Zone 7 capacity price is the MISO-wide capacity price for 2021/2022, but significantly higher for the 2020/2021 and 2022/2023 planning years.[81]

In her rebuttal, Ms. Leslie defended DTE's capacity price forecasts, characterizing the 100% CONE sensitivity as an upper boundary, and further cited Mr. Burgdorf's testimony to show this value "is a real possibility." She described the 50% CONE alternate assumption as "a very reasonable middle range price," and noted that DTE used a $0 price as the lower-end sensitivity. She also defended DTE's use of the PACE forecast as the most recent available forecast at the time of the company's filing. She also testified that actual prices DTE paid in the reverse auction in 2017 "closely compare to 50% CONE."[82]

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[79] See 9 Tr 3761.
[80] See 9 Tr 3762.
[81] See 9 Tr 3763.
[82] See 5 Tr 773.

In his direct testimony, Mr. Burgdorf presented an analysis of the expected Zone 7 resources relative to the Local Clearing Requirement (LCR) for planning years 2019/2020, 2020/2021, and 2021/2022 in his Table 4 at 5 Tr 816, based in part on an April 2019 Loss of Load Expectation (LOLE) study report issued by the MISO Loss of Load Expectation Working Group. He explained:

> Table 4 shows that Zone 7 was only 251 MW long to its LCR in Planning Year 2019/20 and the forecasted Zone 7 capacity length to the LCR remains very tight at less than 2% of LCR in Planning Years 2020/21 and 2021/22. The near-term forecast also indicates there is a chance Zone 7 may be short to the LCR in PY 2021/22. This forecasted situation of little excess Zone 7 resources compared to the LCR presents a near-term reliability concern that Zone 7 may not have enough resources to meet its LCR. Earlier than expected retirement of any of the more than 1,600 MW that comprise DTE Electric's remaining Tier 2 electric generating fleet prior to the planned retirement date of 2022 would exacerbate this issue and likely result in Zone 7 being short of capacity. If Zone 7 were short of capacity and thus the LCR not met, the MISO auction clearing price for Zone 7 would be set at CONE and the probability of a loss of load event (an event in which available capacity is insufficient to serve demand) would exceed the federal reliability standards that govern the resource adequacy planning process.[83]

In his rebuttal testimony in support of DTE's capacity cost assumptions, Mr. Burgdorf cited the November 2019 LOLE study, summarizing the results in his Table 1 at 5 Tr 822-823. He testified the "updated values" show a "probable shortage" in Zone 7:

> MISO updated values for the Local Reliability Requirement (LRR), CIL, Zone 7 Peak Demand, and Zone 7 resources for PY 2020/21 in their most recent LOLE study. The updated values significantly reduce the forecasted LCR Position shown in Table 4 of my Direct Testimony, indicating a probable shortage to LCR in both PYs 2020/21 and 2021/22 if River Rouge Unit 3 retires on May 31, 2020.[84]

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[83] See 5 Tr 817.
[84] See 5 Tr 822.

He further testified:

> As discussed in my direct testimony, if Zone 7 does not meet the LCR, the MISO auction clearing price for Zone 7 would be set at CONE and the probability of a loss of load event would exceed the federal reliability standards that govern the resource adequacy planning process.[85]

Mr. Burgdorf presented two sets of values for Zone 7 resources in each of these tables, as discussed in more detail below.

Mr. Burgdorf also presented an email as Exhibit A-32, Schedule W2 intended to refute Dr. Letendre's testimony regarding the PACE forecast. The email is from someone at MISO and states merely: "As a follow-up, yesterday you inquired if MISO's Capacity Import Limit/Capacity Export Limits (CIL/CEL), used in the calculation of local resource adequacy requirements, are based on UCAP or ICAP. The CIL/CEL calculations are based on the transmission system's ability to transfer power and are not reflective [sic] generator performance (i.e. the CIL/CEL values are "unitless" and the UCAP/ICAP designation is not applicable)." He did not specifically address the footnote in Dr. Letendre's testimony at 9 Tr 3757 intended to show the mathematical inequality that results from failing to adjust the CIL value when using it with ICAP resource values.

d. modeling results

In his analysis, Dr. Letendre incorporated the assumption that industrial gas costs remain at current levels of 50% of natural gas costs, corrected the capital and post-retirement O&M costs, and incorporated DTE's 2020 PSCR plan capacity price forecast along with DTE's capacity price forecasts. The six different capacity price sensitivities

[85] See 5 Tr 823.

Dr. Letendre used are shown in Table 2 of his testimony at 9 Tr 3763, and include the four forecasts used by DTE ($0, 50% of CONE, 100% CONE, and the PACE forecast), the MISO-wide regional price based on his revision to the PACE forecast, and DTE's 2020 PSCR plan forecast. The results of his analysis are shown in Figure 4 of his testimony at 9 Tr 3772, and reflect savings to ratepayers from 2020 retirement under all capacity price scenarios except 100% CONE. The savings figures range from $8.24 million to $0.26 million as the capacity price increases, and the cost to ratepayers at a 100% CONE price is $6.54 million.

DTE did not adjust its results even to correct the capital and O&M cost assumptions that it made no effort to dispute, continuing to assert in its brief:

> [T]he Company's NPVRR analysis showed a range of results from $14 million in favor of continuing to operate the plant through May 2022, to $1 million in favor of retiring the unit in May 2020, depending on the capacity price sensitivity selected (5T 761-62, 775- 76; NPVRR results at Exhibit A-12, Schedule B6.2, page 2). Even assuming that Dr. Letendre's adjustments to the Company's NPVRR are appropriate (which they are not), they still yielded a mixed range of outcomes.[86]

e. omission of previously-disallowed costs

Dr. Letendre also testified that DTE has included in its test year rate base in this case the $10.3 million in capital costs the Commission disallowed in Case No. U-20162. DTE acknowledged this in a discovery response, Exhibit MEC-104, which it quotes in its reply brief, noting it has appealed the Commission's decision in Case No. U-20162.[87] In Exhibit MEC-104, DTE stated:

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[86] DTE brief, pages 31-32; also see DTE reply brief, page 24. .
[87] See DTE reply, page 18.

> Yes, the Company is requesting rate recovery for capital expenditures on River Rouge that were disallowed in one or more of the past three rate cases. The capital expenditures for River Rouge Unit 3 are maintenance-related asset replacements required for the safe and reliable operation of the unit. The Commission has not deferred or disallowed any major maintenance O&M expenditures in the final orders associated with any of the last three rate cases. Please see the attachment for details of the $10.3M capital expenditure disallowance in MPSC Case No. U-20162.[88]

In cross-examination, Mr. Morren made clear that the disallowed capital had not been included in DTE's NPVRR analysis, characterizing the NPVRR analysis as forward-looking.[89]

In this case, given the Commission's prior disallowance, the actual net present value revenue requirement for ratepayers from DTE's proposal would include the additional $10.3 million in capital costs. That is, the real cost to ratepayers of DTE's proposal is at least an additional $10.3 million in addition to what is captured by the NPVRR analysis.

f. summary

This PDF concludes that DTE did not perform an objective analysis of the net present value to ratepayers of continuing to operate River Rouge unit 3 on non-coal fuel through 2020. DTE's analysis clearly omitted $2.4 million in capital and O&M costs, with no explanation for continuing to cite uncorrected figures.

Even before the U.S. Steel announcement, DTE failed to justify its fuel price forecast. Dr. Letendre's analysis is persuasive that DTE did not objectively model projected fuel costs and did not evaluate the risks associated with its fuel blend in relying

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[88] See DTE reply, page 19 at n18.
[89] See 7 Tr 719.

only on a single fuel-cost assumption in its analysis. The MEC Coalition also correctly concluded that the U.S. Steel plant closures cast additional doubt on DTE's ability to obtain industrial gas supplies. While DTE characterizes MEC's argument as "speculation,"[90] it was DTE that proffered a speculative fuel price in the first place, with no sound basis for the forecast, claiming only that its contract was going to be renegotiated so it was not bound by the current contract's coal-based price indexing.[91] Exhibit MEC-45 contains DTE's discovery response regarding its fuel cost assumptions from Case No. U-20471:

> [Q] Given that coal consumption is expected to cease at River Rouge in May 2020, explain the basis for your projected costs of COG and BFG from June 2020 through May 2022 for River Rouge assumed in the NPVRR analysis set forth in Ex. A-17.2.
>
> [A] The Company assumed COG and BFG costs to be 30% of River Rouge natural gas pricing from June 2020 through May 2022 in the NPVRR analysis set forth in Exhibit A-17.2.

Nowhere did DTE provide a more firm or comprehensible basis for its fuel price assumptions in this docket.

Turning to the capacity price forecasts, Dr. Letendre's testimony is persuasive that DTE failed to reflect a reasonable range of capacity price forecasts. Although a zero-cost assumption will define one end of the range, it does not adequately capture the full panoply of outcomes below 50% CONE. Nor is reasonable to conclude that a capacity price of 100% of CONE is a likely outcome. While MISO did update its LOLE study as shown in Exhibit A-32, Mr. Burgdorf's evaluation of that report and his conclusion

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[90] See DTE reply, page 19.
[91] See Exhibit MEC-44, pages 1 and 2, Exhibit MEC-45.

regarding the likelihood of a capacity price equal to CONE do not seem objective or reliable. The November 2019 LOLE study states:

> The actual effective PRM Requirement (PRMR) will be determined after the updated LRZ Peak Demand forecasts are submitted by November 1, 2019, for the 2020-2021 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2020 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings since completion of the LOLE.[92]

Mr. Burgdorf seemed to believe adjustments should be made to the LOLE study report, but did not himself have a very clear understanding of what was already reflected in that study. As noted above, one of his adjustments was to subtract the St. Clair unit 1 capacity, without knowing whether it was already reflected, and adjusted it further in some unspecified way ostensibly to reflect the Staff report in Case No. U-20154. That is, Mr. Burgdorf's rebuttal testimony, Table 1, would show only a 59 MW shortfall without Mr. Burgdorf's undetailed adjustments, which amount to a 13 MW increase for planning year 2020/21 net of his additional reduction for St. Clair unit 1 of 151 MW,[93] and a 407 MW reduction for planning year 2021/22.

Mr. Burgdorf initially acknowledged the LOLE study used PRA information available as of March 2019,[94] and initially acknowledged that MISO would have known of the retirement of St. Clair unit 1 by March 2019 because DTE's Attachment Y was submitted in February 2019.[95] Then he testified:

> I don't think the resources for MISO are from the PRA as a starting point. I know they do different forecasting with these numbers, and they're not the same. I'd have to confirm in the LOLE report here what they would be. But

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[92] See Exhibit A-32, Schedule W1, pages 7-8.
[93] See Morren, 5 Tr 576, for St. Clair unit 1 capacity.
[94] See 5 Tr 873.
[95] See 5 Tr 874.

> the LOLE report was published here in November, so I'm assuming they had updated information around their forecast.[96]

Thus, Mr. Burgdorf acknowledged that he did not have an understanding of where the MISO LOLE numbers came from and what would have been included in them. He also acknowledged that his adjustments were not based on a consideration of resources additions by other utilities because "we don't really have the knowledge behind other people's resources."[97] A comparison of the values in Table 1 of Mr. Burgdorf's rebuttal to the values in Table 4 of his direct testimony, however, shows that his adjustments to the Zone 7 resources in Table 1 merely reproduce the exact same local resource values produced by his adjustments to the Zone 7 resources in Table 4 of his direct testimony. In each case, as a result of his adjustments, the Zone 7 resources are restated to 22,124 MW for planning year 2020/21 and to 21,704 MW for planning year 2021/22, thus discarding any new information regarding Zone 7 resources that may have been reflected in the November 2019 LOLE study relative to the earlier version.

Since Mr. Burgdorf could not establish that the November 2019 LOLE study reflected the most current information regarding Zone 7 resources, however, including DTE's February 2019 Attachment Y filing for St. Clair unit 1 in addition to information provided in the Commission's capacity demonstration docket, Case No. U-20154, it is not reasonable to conclude that it shows a capacity price of 100% CONE is "highly probable."[98] Indeed, because he could not accurately date the information included in the November 2019 LOLE study, this PFD concludes that the PSCR forecast DTE filed

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[96] See 5 Tr 874.
[97] See 5 Tr 880.
[98] See Burgdorf, 5 Tr 822.

in September 2019 in Case No. U-20527 the most current forecast on this record. Note that DTE's September 30, 2019 filing in that docket was made well after the Commission's August 8, 2019 order in Case No. U-20154. Ms. Leslie, who identified four capacity price scenarios for her NPVRR analysis, acknowledged that she did not even review DTE's PSCR forecast in preparing her rebuttal testimony or in preparing for cross-examination.[99]

Because the results of the NPVRR analysis as appropriately revised by Dr. Letendre show clear benefits to ratepayers from a 2020 retirement in all scenarios other than a capacity price equal to CONE, it is not necessary to fully discuss his critique of the PACE forecast. Nonetheless, his testimony is also persuasive that the November 2018 PACE forecast is both stale and contains an error in mixing local reliability requirements and local clearing requirements measured in units of installed capacity with an unadjusted CIL that clearly reflects the difference between local reliability requirements and local clearing requirements measured in units of unforced capacity.[100]

In revising DTE's NPVRR analysis to include additional capacity scenarios, corrected capital and O&M assumptions, and a reasonable fuel cost forecast, Dr. Letendre showed an economic benefit to ratepayers from continuing to operate River Rouge unit 3 only under a 100% CONE capacity cost scenario. The economic benefit he calculated was $6.54 million. Subtracting the additional $10.3 million DTE intends to charge ratepayers if its proposal is adopted shows that even at a capacity cost of 100% of CONE, DTE ratepayers would be worse off (by $3.7 million) if the plant continues to

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[99] See Leslie, 5 Tr 784-785, 788.
[100] Mr. Burgdorf's reliance on the MISO employee's email in Exhibit A-32 is particularly unenlightening because Mr. Burgdorf did not himself analyze its use in the forecast. On cross-examination, he made clear that he did not consider the context. See 5 Tr 847-848.

operate. And this does not consider the risk that DTE may incur significantly higher costs to run the plant on a greater supply of natural gas, given the U.S. Steel announcement.

ii. Grid Reliability

Related to DTE's claim that it should continue to operate River Rouge unit 3 until 2022 is its contention that the unit is needed for capacity. As noted above, Mr. Morren explained that DTE filed an Attachment Y with MISO related to the retirement of all its Tier 2 units in January 2018. He testified that only Trenton Channel Unit 9 was deemed a system support resource (SSR).[101] Mr. Morren then testified:

> These studies conclude that reliability issues identified related to the suspension of the River Rouge and St. Clair units would not require the units to be designated as SSR units. However, the reports do indicate that retirement or suspension of these units may create thermal and voltage issues that could require the Company to shed load to firm customers 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 the River Rouge and St. Clair Power Plants until their planned retirement dates will provide time to identify and implement alternative solutions that can ensure continued reliable electric service for its customers.[102]

Dr. Letendre took issue with DTE's contention that continuing to operate River Rouge unit 3 provides reliability benefits to MISO Zone 7, challenging its reliance on the MISO Attachment Y study to justify continuing to operate the unit:

> DTE provides no support to demonstrate any need to actually load-shed at any point during the period 2020-2022, if River Rouge 3 were to be retired in May of 2020. Mr. Morren's testimony includes a single question and answer, referencing an Attachment Y study from March 2018, with no indication of whether its results for 2020 are still valid. No evidence is

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[101] See 5 Tr 623-624.
[102] See 5 Tr 624.

> provided that indicates forecasted conditions in 2020 would be such that firm load shed would be required to maintain reliability.[103]

Further, he challenged Mr. Morren's testimony that the unit's capacity would be needed in the event other Tier 2 units are forced to retire earlier than planned:

> DTE suggests that the capacity is needed in case other units that the Company plans to retire in the next few years are forced to retire earlier than the currently planned retirement dates, but provides no evidence to indicate that this is reasonably likely, especially given that planning reserve margins are purposely set higher than peak load in part to allow for forced outages. DTE's assertion is akin to opining that the MISO-developed reserve requirement is too low; DTE provides no evidence that this is the case.[104]

In rebuttal testimony, Mr. Morren relied on Mr. Burgdorf's analysis regarding the risk of firm load shed if River Rouge unit 3 does not operate, based on the November 2019 LOLE study.[105] In addition to the November 2019 LOLE study, discussed above, Mr. Burgdorf presented a letter from this Commission as his Exhibit A-32, Schedule W3. This letter is dated November 7, 2019, and acknowledges the LOLE Study: "As you know, Michigan is experiencing a significant number of power plan retirements and has the potential to be short of meeting the LCR in MISO's upcoming MISO Planning Resource Auction (PRA) based on MISO's loss of load expectation study." The letter asks MISO's assistance in understanding the effects of increasing the CIL and CEL into and out of Zone 7:

> Our first request is for MISO to analyze increasing the CIL and CEL in the near term at smaller increments such as 500 MW and 1,500 MW. The goal is to determine the infrastructure needed to accommodate cost-effective increases in the near term, with corresponding costs and benefits to Zone 7 and other Zones as applicable. Second, we seek to understand what

[103] See 9 Tr 3775.
[104] See 9 Tr 3775-3776.
[105] See 5 Tr 656.

> types of projects could facilitate an increase in the CIL and CEL in Zone 7 by larger increments over the next decade to accommodate additional renewable energy and other changes in the generation mix. . . .We would also like to understand how the costs of any projects proposed to increase the CIL and CEL would be allocated under the current MISO tariff, as well as explore other cost allocation methodologies that could be beneficial to furthering the development of transmission projects to increase the CIL and CEL for Zone 7.[106]

In its brief, the MEC Coalition argues:

> On cross exam, Mr. Burgdorf acknowledged at least some uncertainty concerning his updated projections. While Mr. Burgdorf adjusted his Zone 7 capacity resource total downward to account for the retirement of St. Clair Unit 1, he did not make any upward adjustments for potential resource additions in Zone 7 since December 2018 or March 2019 when the data he relied on was submitted to Commission Staff and MISO. Mr. Burgdorf did not know whether the Commission's recent approval of the River Fork solar project between Consumers and Ranger Power should be added. Nor did he know whether the October 7, 2019 approval of Consumers' Crescent Wind park should be added. Because his update was one-sided, making a large downward adjustment but no upward adjustments, it is not clear that his table should be relied on for the claim he makes that Zone 7's capacity position is so tight that River Rouge 3 could be the difference maker.[107]

DTE responded in its reply brief, contending that "'potential' projects involving other parties" are beyond the company's control.[108]

In light of this PFD's findings regarding DTE's economic analysis, this PFD finds that grid reliability does not support continuing the uneconomic operation of River Rouge unit 3 as DTE proposes. The Commission's May 2, 2019 order in Case No. U-20162 was one in a series of orders faulting DTE for an erroneous economic analysis. The potential load shedding was a factor DTE raised in that case, in consideration of which the PFD explained:

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[106] See Exhibit A-32, Schedule W3.
[107] See MEC brief, page 33.
[108] See DTE reply, page 23.

> 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 years to devise a solution for this potential problem, and it failed to do so.[109]

It should also be noted that the November 2019 letter DTE included in Exhibit A-32 was written well after the Commission issued its decision in Case No. U-20162, that is, well after the Commission disallowed DTE's projected capital expenses for the continued operation of River Rouge unit 3. It is also worth noting that in its recent capacity demonstration case order in Case No. U-20154, the Commission explained that the resources for Zone 7 may look tighter than they really are:

> The Staff notes that its findings show that LRZ 7 would fall short of meeting its LCR by 232 zonal resource credits (ZRCs) in 2019, but explains that this occurs when only demonstrated resources are considered. LRZ 7 meets its LCR when including known resources within the zone that were excluded from capacity demonstration filings. Id., pp. 8-9. The Staff notes that several capacity requirement and resource changes are taking place in 2019, including an increased local reliability requirement, an increased LCR, and an increase in demand response (DR) programs.[110]

This PFD does not find grid reliability justifies the continued uneconomic operation of the unit.

iii. Environment

The parties also disagree on the potential environmental impact of DTE's proposal. Citing Mr. Morren's testimony, DTE argues that burning industrial gas that would otherwise be flared benefits the environment.

Dr. Letendre disagreed with DTE's assertion.[111] Noting that DTE's own modeling shows that it will run the plant on natural gas 20% of the time, Dr. Letendre testified that

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[109] See PFD, Case No. U-20162, pages 47-48.
[110] See August 8, 2019 order, page 3.
[111] See 9 Tr 3777-3778.

natural gas would not otherwise be flared and will produce additional CO_2 and other emissions. Dr. Letendre further disputed that the industrial gas would indeed be flared, characterizing DTE's evidence as "weak, based on Company reported 'visible observations' and data points that the gas is currently flared when River Rouge is on outage."[112] He testified that the industrial gas has a higher sulfur content than the coal the plant is currently burning, resulting in higher SO_2 emissions by DTE's own analysis.

In his rebuttal testimony, Mr. Morren cited testimony from a DTE witness in Case No. U-20471 asserting that operation of River Rouge Unit 3 on gasses will emit significantly less from an overall emissions standpoint than burning coal.[113] He also reiterated the testimony he gave on direct that burning the industrial gasses is preferable to flaring them. He further explained:

> The byproduct industrial gases must be consumed in one of two places—either by the facilities and flares on Zug Island or by River Rouge Unit 3. The industrial gases being used as a fuel by River Rouge Unit 3 are a byproduct of the coke and steel making process. The byproduct industrial gases must be consumed in one of two places—either by the facilities and flares on Zug Island or by River Rouge Unit 3. The production and consumption of industrial gases will take place regardless of River Rouge Unit 3's operation. By recycling the industrial gases as fuel for River Rouge Unit 3, energy in the fuel can be recaptured instead of being wasted to the atmosphere through flaring. Furthermore, the recycling of the industrial gases eliminates the need to burn fuel at another location to produce the electrical energy that River Rouge Unit 3 is forecasted to produce.[114]

As noted above, at the conclusion of the hearing, U.S. Steel announced that it would close several plants, which calls into question the amount of industrial gas DTE

[112] See 9 Tr 3777-3778, citing DTE discovery responses.
[113] See 5 Tr 657.
[114] See 5 Tr 658.

would actually be able to burn. DTE's discovery response in Exhibit MEC-130 is quoted above.

This PFD finds DTE has not established a net environmental benefit to its proposal.

iv. Community Impact

In addressing DTE's argument that the community impact, including impact on the local tax revenues, justify a later retirement date, Dr. Lentendre testified that DTE could consider other forms of community support such as "payment in lieu of taxes" or PILT:

> While DTE can and should consider community impacts when shutting down a plant, these potential tax impacts do not justify continued operation of an uneconomic plant at the expense of ratepayers. DTE should consider the impact that reduced operations and then retirement has on the tax base and evaluate alternative options to support the community.[115]

In rebuttal, Mr. Morren testified that community impact was just one of many considerations underlying DTE's decision, and further testified: "Paying amounts that are not authorized or required by law would impose an unfair and unauthorized burden on our customers."[116] He did not explain why operating a unit uneconomically for the benefit of the community would not be an equivalent or greater burden on customers. Indeed, DTE's response to Dr. Letendre's discussion of community impacts and the opportunity for payments in lieu of taxes undermines its argument that community impacts should be considered in addition to economic arguments.

This PFD finds that DTE has not established a community impact that would justify the extended uneconomic operation of River Rouge unit 3. First, there has been no

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[115] See 9 Tr 3776.
[116] See 5 Tr 657.

showing that the Commission did not adequately consider community impacts in its earlier determination. Second, where, as here, the economics do not support the project, DTE's own argument against a payment in lieu of taxes indicates that it would not be appropriate to continue operation of the plant to mitigate community impacts.

b. Routine Projects

In discussing DTE's fossil generation capital planning process, Mr. Morren explained the steps involved from the initial request form and the required information, further project development, prioritization using an internal rate of return analysis, and presentation for management review and approval.[117] He testified that projects are approved "if they are justified by an economic evaluation or required to meet safety and/or environmental regulations."[118] Projects costing more than $250,000 but less than $10 million are reviewed by the Capital Governance Board, which includes plant directors, the Director of Engineering, and the Senior Vice President of Fossil Generation. Projects costing more than $10 million require senior corporate executive approval or approval by the Finance Committee of DTE's Board of Directors.[119]

The Attorney General took issue with several of the projects DTE categorized as routine in Schedule B5.1 of Exhibit A-12.[120] In his analysis, Mr. Coppola considered the projects planned within each calendar year, 2019, 2020, and the first four months of 2021. Also see Exhibits AG-1.8, AG-1.9, and AG-1.10. Mr. Coppola addressed 20 projects of the more than 150 projects listed in that schedule (101 for 2019 through the first 4 months

[117] See 5 Tr 586-589.
[118] See 5 Tr 587.
[119] See 5 Tr 588-589.
[120] See Attorney General brief, pages 72-74.

of 2021), taking issue with projected expenditures totaling $43.0 million relative to DTE's total projected capital expenditures of $429 million for routine steam generation projects. He reviewed the project documentation, including the Project Authorization Template (PAT) Review Request Forms.[121] ABATE also objected to the capital expenditures associated with three of those projects, based on Ms. York's testimony.[122]

In the discussion that follows, the projects are discussed in the order presented by Mr. Coppola, beginning with projects planned for 2019 followed by projects planned for 2020, in subsections i) through xiii). He considered the projects planned for the first four months of 2021 collectively, so they are addressed collectively in subsection xiv).

At a general level, in his rebuttal testimony, Mr. Morren objected to Mr. Coppola's reliance on the company's PAT forms, contending that those forms need not be updated until the funds are spend, and thus do not reflect the company's latest forecasts for its future capital project expenditures. Thus, he testified:

> Development of the projected (forecasted) yearly capital expenditures in this case requires the Company to rely on forecasts. Fossil Generation updates its forecasts for all its capital projects monthly. These monthly project forecasts will change based on new information as the project details are finalized and project execution moves forward. On the other hand, the PAT forms authorize the initiation of the project, including acceptance of project charges, and are updated to approve specific project execution phases, including initiation of engineering, long lead material procurement, and finally construction. Capital expenditure forecasts are performed monthly while project approval document updates occur as needed. Therefore, a proposed disallowance based merely on a comparison between annual amounts included in project approval documents and annual expenditures in the rate case forecast is without merit.[123]

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[121] See 9 Tr 2986, 2989, 2994.
[122] See ABATE brief, pages 22-23.
[123] See 5 Tr 645.

And further:

> The Company is cognizant of the need to provide the best available forecasts for its future capital project expenditures. As such, it relies on the latest project forecasts and not the PAT approval documents. In some cases, project approval documents do not yet contain the most recent information, nor are they required to by Company policy. Company policy requires project approval documents to be updated and approved before the funds are spent, not before they are forecasted for a future time frame expenditure. Proposed disallowances based on a comparison between annual amounts included in project approval documents and annual expenditures in the rate case forecast are not warranted because the projects have management approval and the values provided in the rate case exhibits contain the best information available at the time of the rate case filing.[124]

He also testified: “The Company’s management reviews and approves the rate case testimony and capital requests shown on the routine capital expenditure Exhibit A-12, Schedule B5.1, pages 5 to 7 prior to filing.”[125] And he disputed that any project could be considered “premature for inclusion in the rate case,” because the cost estimates have been reviewed and received approval by the Fossil Generation Capital Governance Board during their monthly review meetings.[126] In its brief, DTE asserts “the Fossil Generation Capital Governance Board (CGB, which consists of plant directors, the Director of Engineering, and the Senior Vice President of Fossil Generation) reviewed and approved the funding allocations shown in exhibit A-12, Schedule B5.1,” citing Mr. Morren’s rebuttal testimony 5 Tr 644-646.[127]

As a review of Exhibits AG-1.8 through AG-1.10 shows, the information contained in the PAT documents DTE has presented in support of its projections contain minimal

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[124] See 5 Tr 645-646.
[125] See 5 Tr 646.
[126] See 5 Tr 646.
[127] See DTE brief, page 23.

information. They generally include engineering, procurement, and installation in one cost estimate, with no separation as to timing or cost. DTE's argument that other cost reviews take place, with no documentation regarding either the approved costs or the date and nature of the review, and that these reviews are a reliable part of a "rigorous" process of cost review, is wholly unsupported by the record in this case. Predominantly, the documents cited by Mr. Coppola and Ms. York are the only documents offered for this record regarding the costs at issue. The Commission has expressed a preference for documented and approved expense projections. It is difficult to conceive of any cost review taking place in the absence of documentation with at least the minimal detail included in this PAT forms, or that it could be considered in any way burdensome for the minimal information contained on those documents to be updated, should a review take place. For these reasons, in the event of an unexplained inconsistency between the PAT forms and the projections in DTE's schedules as discussed below, this PFD generally finds that the minimally-documented projections should be adopted in lieu of undocumented ones.

i. Belle River Unit #1 Turbine Steam Path Replacement

Mr. Morren testified that DTE will spend $7.2 million in 2019 to engineer and procure a replacement HP turbine for Belle River unit 1.[128] Mr. Coppola testified that the February 27, 2018 PAT form for this project stated the project would start in March of 2021 and the installation would be made in May 2021, while a subsequent February 20, 2019 PAT form changed the start and installation dates to February 6, 2019 and June 10,

[128] See 5 Tr 605.

2019 respectively. He testified that the second PAT form proposed spending $3.3 million in 2018 and $8.5 million in 2019, but no 2018 spending occurred. Citing Exhibit AG-1.8, he testified:

> Given the lack of spending in 2018 and the uncertain dates when this project will begin and end, it is my conclusion that the requested capital spending on this project will not likely occur within the projected periods. Therefore, I recommend that the entire amount of $7,212,002 forecasted by the Company for 2019 be removed.[129]

In his rebuttal testimony, Mr. Morren asserted that $2.8 million was spent in 2018 on this unit, citing page 4, line 1 of Schedule B5.1, and that the project was completed during the spring 2019 periodic outage for the unit.[130] In its brief, DTE contends that "Mr. Coppola apparently ignored or misread the Company's testimony, exhibits and discovery response," and relies on Mr. Morren's testimony.[131] DTE's reply brief repeats the statements in its initial brief, also taking issue with what it characterizes as a "lack of specificity" in the Attorney General's brief.[132]

This PFD accepts Mr. Morren's testimony that the project was completed in 2019, and notes the 2018 and 2019 expenditures on lines 1 and 52 of Schedule B5.1, pages 4 and 5. This PFD also notes, however, discrepancies between the project costs included in Schedule B5.1 and the PAT forms. As shown in Exhibit AG-1.8, page 3, as of February 2019, DTE's total projected costs were $12.25 million for 2018 and 2019, not including contingency. DTE's total reported costs for this completed project is $9.95 million, making

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[129] See 9 Tr 2987.
[130] See 5 Tr 643.
[131] See DTE brief, page 23.
[132] See DTE reply, pages 12-13.

its February cost estimate for spring 2019 installation significantly overstated. The February PAT form overstated not only 2019 costs but also 2018 costs.

ii. Monroe Power Plant Unit #3 SCR Catalyst Layers

In his direct testimony, discussing 2018 expenditures, Mr. Morren testified that: "For Monroe Unit 3, $3.5 million was spent to procure SCR Catalyst Layers 1, 2, 3, and 4 for upcoming periodic outage work to comply with air permit emissions limits for NOx and ammonia slip guidelines."[133] Mr. Morren then specifically referenced the 2019 work in his testimony at 5 Tr 607: "$6.8 million will be spent on replacing SCR Catalyst layers 2, 3, and 4 to comply with air permit emissions limits for NOx and ammonia slip guidelines."

Mr. Coppola recommended a $346,871 reduction to the 2019 cost projection on line 65 of Schedule B5.1, page 5, of $6,819,992 because the cost projection excluding contingency included in the PAT form for the project was only $6,473,121.[134] The PAT form he relied on is page 4 of Exhibit AG-1.8.

In his rebuttal testimony, Mr. Morren addressed DTE's projected spending for 2021 for Monroe unit 3, stating:

> The Monroe Unit 3 SCR catalyst project also represents work the Company routinely completes, *and a similar project was completed in 2019*. The forecast shown for this project is reasonable based on the Company's past experience, thus the disallowance of this forecast is not warranted.[135]

He did not address this project spending specifically. In its brief, DTE relies on Mr. Morren's testimony.

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[133] See 5 Tr 601.
[134] See 9 Tr 2987-2988.
[135] See 5 Tr 648 (emphasis added).

Because Mr. Morren had the opportunity to address the 2019 cost estimate for the Monroe unit 3 SCR work and did not, and because Mr. Coppola correctly identified a discrepancy between the rate filing cost estimate and the PAT form that DTE did not justify, this PFD finds that Mr. Coppola's adjustment should be adopted. This PFD further notes that Mr. Morren's testimony that DTE spent $3.5 million on this project in 2018 also does not match either the May 2019 PAT form showing $2,344,633 in spending for 2018, or the 2018 spending DTE reported on line 13 of Schedule B5.1, page 4.

iii. Monroe Unit #3 Expansion Joint Replacement

Mr. Morren stated in his direct testimony:

> Boiler combustion control and unit reliability require that various expansion joints be replaced for $5.1 million. The boiler flue gas system has over 100 expansion joints on each unit and these expansion joints have a finite life requiring a continuing replacement program. These replacements are part of that continuing program.[136]

Again concluding that the company's 2019 expense projection for this item, $5,100,423 on line 66 of Schedule B5.1, page 5, did not match the May 2019 PAT form estimate of $4,060,603 as shown on page 5 of Exhibit AG-1.8, Mr. Coppola recommended a $1,060,200 reduction to the 2019 rate case expense to match the May 2019 PAT form cost estimate.[137]

This PFD finds the Attorney General's adjustment appropriate. DTE did not explain the basis for the higher projection in its rate case filing when only a few weeks

[136] See 5 Tr 607.
[137] See 9 Tr 2988.

before, DTE's filing projected a lower cost. Note that in its discovery response in Exhibit AG-8, page 1, DTE directed the Attorney General to this documentation.

iv. Belle River Unit 13-1 Major Overhaul

For this project, Mr. Morren testified that DTE would spend $7.5 million in 2019 for turbine combustion cans and hot gas path overhaul on the Belle River 13-1 peaking unit "require based on unit running hours and the number of unit startups."[138] Mr. Coppola identified a $578,903 discrepancy between the company's projected capital expenditure of $7.5 million for 2019, included on line 90 of Schedule B5.1, page 5, and the March 2019 PAT form estimate of $6,921,097, excluding contingency amounts, shown on page 6 of Exhibit AG-1.8.[139] In the absence of any alternative documentation supporting DTE's higher rate case estimate, this PFD finds that Mr. Coppola's adjustment should be adopted.

v. Delray Gas Compressors Replacement

Mr. Morren identified a 2019 expenditure of $4 million "to engineer and procure a gas compressor at the Delray Peakers."[140] He also included a $2.5 million projected expenditure for 2020 to "execute the installation of a new gas compressor at Delray."[141] Mr. Coppola recommended that the Commission exclude the company's $4 million projected capital expenditure for this project on the ground that the cost projection is speculative. Citing the project approved PAT form at page 7 of Exhibit AG-1.8, Mr. Coppola testified:

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[138] See 5 Tr 615.
[139] See 9 Tr 2988.
[140] See 5 Tr 615.
[141] See 6 Tr 616.

> The project PAT form dated March 27, 2019 describes the project summary scope as follows: "Vendor to prepare a gas compressor technology assessment to assist DTE in selecting new compressors. Once compressors technology is chosen by DTE, vendor will provide a formal bid spec." This description indicates that the project is in the early stages of development with no decisions made as to how to proceed with the project. The forecast appears to be a "ballpark" amount as a placeholder for the purpose of preparing a rate case forecast. The project and cost estimate are premature for inclusion in this rate case. Therefore, I recommend that the entire $4 million be removed from the forecasted capital expenditures for 2019.

Mr. Morren's direct testimony merely asserted that the $4 million would be spent in 2019 to engineer and procure the compressor, with $2.5 million slated for 2020 to install the gas compressor.[142] He did not specifically address this Delray project in his rebuttal testimony, and DTE did not specifically address it in its brief, beyond its general objection to reliance on the PAT forms.

This PFD finds that DTE did not support the reasonableness of this proposed expenditure, in the absence of the referenced assessment and vendor bidding, it is premature to estimate costs for this project. Again, this PFD notes that DTE was specifically asked in discovery for information why this project would be completed as proposed and did not provide any response other than a reference to the planned outage schedule and the PAT form documentation.

vi. Belle River Unit #2 LP Turbine Blade Replacement

Turning to projected 2020 capital expenditures, Mr. Morren testified at 5 Tr 609 that DTE would replace all blades for the LP turbine due to erosion. The projected rate

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[142] See 5 Tr 615, 616.

case expenditures for 2020 are shown on line 103 of Schedule B5.1, page 6. Mr. Coppola took issue with the projected spending for this project:

> The capital expenditures amount included in the Company's forecast for 2020 is $7,448,100. The approved amount on the project PAT form dated January 1, 2019 is $6,200,707 for Future Years, excluding the contingency amount (Calculated Risk). The difference is $1,247,393. Although, it is not clear if Future Years is only 2020, or may include subsequent years, the rate case forecast is not supported by the project approval document. Therefore, I recommend that at least $1,247,393 be removed for the rate case forecast for 2020. A case could be made that the entire amount of $7,448,100 should be removed given that there is no specific approval for spending this amount on the project in 2020.[143]

The January 2019 PAT form he cited is page 1 of Exhibit AG-1.9.

Ms. York did recommend that the entire projected expense be rejected, testifying that DTE has not provided information showing that it will indeed incur the costs to engineer and procure the replacement blades before the end of the test year, noting, however, that ABATE had issued further discovery on this topic and was awaiting an answer.[144]

In his rebuttal testimony, Mr. Morren responded that information on the project timing associated with periodic outages for the units was provided in discovery, which he included in Schedule DD2 of Exhibit A-39. Specific to Belle River unit 2, he testified that its periodic outage is scheduled from January to May 2020, and asserted that the disallowances proposed are not justified based on the evidence provided by the company.[145]

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[143] See 9 Tr 2990.
[144] See 7 Tr 1943.
[145] See 5 Tr 642-643; also see DTE brief, pages 22-23.

This PDF finds that Mr. Coppola's adjustment should be adopted. This PFD further notes that the PAT form indicates that four replacement blades will be ordered, but two may not be needed. While this is inconsistent with Mr. Morren's testimony, it does indicate some work is required.

vii. Belle River Unit #2 IP Turbine Blade Replacement

Mr. Morren also testified that DTE's 2020 capital expenses include projected expenditures of $4.9 million for IP blade replacement, as shown on line 105 of Schedule B5.1, page 6, due to erosion damage.[146] Citing Exhibit AG-1.9, page 3, Mr. Coppola recommended a $3.5 million reduction in the company's forecast 2020 capital expenditure for the Belle River unit 2 IP turbine blade replacement project, based a discrepancy between the rate case forecast of $4,884,000 and the May 2019 PAT form approved amount of $1,362,402 for 2020, excluding the contingency amount.[147] Although asserting that $4.9 million would be spent in 2020 in his direct testimony,[148] Mr. Morren did not provide any cost detail regarding this project in his rebuttal testimony, so there is nothing in this record that purports to explain the additional $3.5 million projected expenditure. Thus, this PFD finds that DTE has failed to establish it will spend the projected amount in 2020 and recommends that Mr. Coppola's adjustment be adopted.

viii. Greenwood Unit #1 Main Unit Transformer Replacement

Mr. Morren testified that in preparation for a future periodic outage at Greenwood Energy Center, DTE will spend $1.2 million in 2019 and $8.0 million in 2020 to engineer

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[146] See 5 Tr 609.
[147] See 9 Tr 2990.
[148] See 5 Tr 609.

and procure a Main Unit Transformer.[149] He explained: “The existing Main Unit Transformer is gassing (a sign of degradation) and has reliability concerns.”[150]

Mr. Coppola recommended an adjustment to the 2020 expense projection to reflect the $400,000 lower projection on DTE’s PAT form for this project, as shown in Exhibit AG-1.9, page 4. Ms. York recommended rejecting both the 2019 and 2020 projected expenditures on Greenwood unit 1. She testified that DTE had failed to provide information showing that it will indeed incur the costs during the bridge period or test year. She again indicated that ABATE had issued further discovery and was awaiting a response.[151]

This PFD accepts Mr. Morren’s testimony that the work will be performed, but in the absence of additional specific cost detail, finds that Mr. Coppola’s adjustment should be adopted.

ix. Monroe Unit #4 Secondary Superheat Inlet Pendant Replacement

In his direct testimony, Mr. Morren identified a $12.3 million expenditure “for the SSH inlet pendant project which replaces the 53 SSH inlet pendant assemblies that are 45 years old.”[152] Mr. Morren’s direct testimony also indicated that $1.7 million had been spent in 2018 to procure SSH pendant materials in preparation for a periodic outage at

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[149] See 5 Tr 606, 610.
[150] See 5 Tr 610.
[151] See 7 Tr 1944.
[152] See 5 Tr 611.

the unit,[153] and that a $3 million expenditure is planned for 2019 to replace 53 inlet pendant assemblies,[154] with an additional $12.3 million for 2020.[155]

Mr. Coppola's recommended $585,000 reduction to DTE's 2020 projection for this project is based on the discrepancy between the approved amount of $11.7 million "for future years" in the March 2019 PAT form and the company's rate case projection of $12.3 million.

Mr. Morren did not specifically address this project in his rebuttal testimony. Since DTE provided no other supporting documentation for its cost estimate, this PFD finds that Mr. Coppola's adjustment should be adopted.

x. Monroe Unit #4 Generator Stator Rewind

Mr. Morren testified that DTE plans to spend $5.8 million in 2019 for "engineering and procurement to support future generator stator outage work," and $8.4 million in 2020 because "the generator stator is approaching 45 years of age and needs to be rewound."[156] He further testified that "the generator is experiencing vibration caused by deteriorated retaining springs leading to insulation breakdown as well as stator cooling water system brazed joint leakage caused by corrosion allowing additional loss of insulation integrity leading to electrical failures."[157]

Both Mr. Coppola and Ms. York recommended adjustments to the projected expenditures for this project. Mr. Coppola's recommendation that "at least $288,663" be

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[153] See 5 Tr 602.
[154] See 5 Tr 608.
[155] See 5 Tr 611.
[156] See 5 Tr 608, 611.
[157] See 5 Tr 611.

removed from the 2020 projection is based on a discrepancy between the company's projection and its PAT form, Exhibit AG-1.9, page 5, which also was not specific as to the "future years" in which the projected expenditures would take place.[158] Ms. York recommended that the $5.8 million proposed for engineering and procurement in 2019 be rejected, again expressing her opinion that DTE had not established that it will indeed incur these costs, and again referencing outstanding discovery on this issue.[159]

As noted above, in his rebuttal, Mr. Morren referred to the project timing information provided to the parties in discovery as shown in Exhibit A-39, Schedule DD2, which lists a Monroe unit 4 periodic outage scheduled for September through December 2020, but did not specifically address the project in any detail. This PFD accepts Mr. Morren's testimony that work will be performed at the periodic outage, but finds that Mr. Coppola's adjustment should be adopted.

xi. Monroe Turbine & Boiler House Roof Vent Fan Replacement

Mr. Morren described this project for 2020 spending for this project on Monroe common plant as "$3.0 million will be spent to procure and install Turbine and Boiler Vent Fans."[160] The projected expense is included on line 135 of Schedule B5.1, page 6. Mr. Coppola characterized DTE's 2020 projected expenditure for turbine and boiler house roof fan replacement at Monroe as a "ballpark" amount:

> The project PAT form dated December 5, 2018 describes the reason for project submittal as follows: "At this time, this project is below the line for 2019. It is understood that the funding approved with this request is limited to support the development of an equipment specification and the work to support the bid event for the new fans. Any further engineering or

[158] See 9 Tr 2992; Exhibit AG-1.9, page 6.
[159] See 7 Tr 1944.
[160] See 5 Tr 612.

> procurement is not allowed until a funding path is established for execution." This description indicates that the project is in the early stages of development with no decisions made as to how to proceed with the project. The forecast appears to be a "ballpark" amount as a placeholder for purpose of preparing a rate case forecast. The Commission has previously rejected such placeholder amounts. The project and cost estimate are premature for inclusion in this rate case.[161]

In the absence of additional documentation supporting that this project will occur in view of the statements in the PAT form, this PFD finds that Mr. Coppola's recommendation to exclude the projected spending for this project is reasonable and should be adopted.

xii. Hancock 11-4 Peaker Hot Gas Path Overhaul

Mr. Morren described this project for 2020 as "$4.0 million to conduct a hot gas path inspection at Hancock 11-4."[162] The projected expense is shown on line 145 of Schedule B5.11, page 6. Mr. Coppola objected to the projected $4 million expenditure for this Hancock peaker project, based on a lack of supporting documentation:

> The project PAT form provided to support the capital expenditure is neither dated nor signed. The forecast appears to be a "ballpark" amount as a placeholder for purpose of preparing a rate case forecast. The Commission has previously rejected such placeholder amounts. The project and cost estimate are premature for inclusion in this rate case. Therefore, I recommend that the entire $4 million be removed from the forecast capital expenditures for 2020.[163]

The unsigned form he cited is page 8 of Exhibit AG-1.9. While asserting in his direct testimony that DTE would spend $4 million to conduct a hot gas path inspection at Hancock 11-4, he did not further address this project in his rebuttal testimony.

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[161] See 9 Tr 2992.
[162] See 6 Tr 616.
[163] See 9 Tr 2993.

The PAT form cited by Mr. Coppola also states: “Based on the run hours and number of starts Hancock 11-4 Peaker has experienced, it is expected that the hot gas path components will need to be replaced in 2020.” The cost estimate includes $1.8 million in materials as well as labor, and thus appears to include more than “inspection” costs, but to actually estimate the cost of replacement, in advance of an actual inspection. This PFD finds that in the absence of more detailed documentation, Mr. Coppola’s adjustment should be adopted.

xiii. Renaissance Unit #1 Peaker Turbine Combustion Cans and Hot Gas Path Replacement

Mr. Morren described the projected 2020 expenditure for this line item as “$4.0 million to engineer and procure material 5 for a Renaissance Peaker Major Overhaul.”[164] Similarly to the foregoing, Mr. Coppola objected to a $4 million projected expense for hot gas path replacement for Renaissance unit 1:

> The capital expenditures amount included in the Company’s forecast for 2020 is $4,000,000. The project PAT form provided to support the capital expenditure is neither dated nor signed. The forecast appears to be a “ballpark” amount as a placeholder for purpose of preparing a rate case forecast. The Commission has previously rejected such placeholder amounts. The project and cost estimate are premature for inclusion in this rate case.[165]

The unsigned PAT form for this project that Mr. Coppola cited is page 9 of Exhibit AG-1.9. Its problem description states: “Based on the number of starts Renaissance Unit 1 has experienced, it is expected that the combustion, hot gas, and compressor components will need to be replaced in 2021.” Noting that the unsigned form includes $0

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[164] See 5 Tr 616.
[165] See 9 Tr 2993.

for 2020, and that the $4 million for 2021 is primarily for materials, this PFD finds that Mr. Coppola has correctly identified the company's 2020 rate case projection for this item as premature and merely a place holder.

xiv. 2021 Projects

Addressing a total of 7 projections with projected 2021 expenditures totaling $12.8 million, reflected on Schedule B5.1, page 7, Mr. Coppola recommended that the projected expenses be rejected as placeholder amounts:

> On page 7 of Exhibit A-12, Schedule B5.1, the Company listed 7 projects with expenditures above $1 million during the four months ending April 2021. The Total amount of forecasted capital spending for these projects during the 4-month period is $12.8 million. After reviewing the project PAT Request forms for most of these projects, the projects do not have dated or approved PAT forms or have forms with no designated and approved capital spending for 2021. [166]

As noted above, in rebuttal, Mr. Morren asserted that the lack of signed documentation or cost estimates should be ignored because all projects were reviewed by "the Company's management," as part of its review and approval of the rate case testimony prior to filing.[167] He further characterized the projects as "not placeholders," but "specific projects mainly associated with the Greenwood period outage which will be completed between March and May of 2021."[168] Mr. Morren did provide rebuttal testimony specifically identifying the projects, primarily focusing on the company's experience estimating the cost of types of work:

> The Greenwood main unit transformer project is a multiyear project initially started in 2018 with its completion scheduled coincident with the Spring 2021 Greenwood periodic outage. This project has a total approval of $12.9

[166] See 9 Tr 2994.
[167] See 5 Tr 646.
[168] See 5 Tr 647.

> million of which the majority is expected to be spent prior to 2021. The recommended disallowance has no merit.
>
> The Greenwood Condenser Air Removal Tubes project is a well-known type of routine work. The Company has re-tubed many condensers in the last ten years and is very familiar with the work and the cost to complete the work. The forecast shown for this project is reasonable based on the Company's past experience, thus the disallowance of this forecast is not warranted.
>
> The boiler feed pump turbine blade replacement projects are also well-known in that the Company has completed at least 10 projects on nearly identical GE boiler feed pump turbines in the last 5 years. The forecast shown for this project is reasonable based on the Company's past experience, thus the disallowance of this forecast is not warranted.
>
> The Company also has a lot of experience with turbine valve work and completes projects similar to that forecasted for Greenwood in 2021 on a nearly annual basis. The forecast shown for this project is reasonable based on the Company's past experience, thus the disallowance of this forecast is not warranted.
>
> The Monroe Unit 3 SCR catalyst project also represents work the Company routinely completes, and a similar project was completed in 2019. The forecast shown for this project is reasonable based on the Company's past experience, thus the disallowance of this forecast is not warranted.
>
> The final project being disputed by Witness Coppola is associated with upgrades to the Monroe Power Plant Unit 1 control system. The forecast shown for these projects is associated with routine work planned mainly for a scheduled periodic outage and is reasonable based on the Company's past experience.[169]

This PFD finds that Mr. Coppola's recommended adjustment is consistent with the documentation provided by DTE and should be adopted. As shown in Exhibit AG-1.10, DTE was asked specifically to establish that the projected amounts would be spent within the projected test year, and provided only the documentation in Exhibit AG-1.10. Mr.

[169] See 5 Tr 647-648.

Morren's testimony acknowledges that the Greenwood outage may be within the test year, or may not be until May 2021. While Mr. Morren cites costs expected to be incurred in 2020 for the Greenwood transformer project, the 2020 spending projections are not covered by this adjustment, but are discussed in section viii) above. Note that if DTE follows its recent pattern of rate case filings and files its next rate case in July 2020, and can demonstrate actual capital expenditures planned for March-May 2021, it should be able to begin recovering those costs as soon as May 2021.

c. Non-Routine Projects (Monroe Coal Ash)

Mr. Morren testified regarding DTE's plans to meet EPA Coal Combustion Residual (CCR) requirements at the Monroe power plant.

In its May 2, 2019 order in Case No. U-20162, the Commission addressed DTE's request in that case to include $34.1 million in rate base to comply with U.S. EPA effluent limits. The Commission explained the objections to the funding:

> Though supportive of the goals as a whole, the Staff proposed disallowance of approximately $34.1 million in proposed costs for the four-month bridge period and the test year combined, based on the fact that DTE Electric has not received full internal approval for all of the projects and has not executed an engineering, procurement, and construction (EPC) contract yet. The Staff also indicated that it had inadequate information regarding the net present value revenue requirement (NPVRR) of the projects. The Attorney General recommended disallowance of $90.9 million. MEC/NRDC/SC supported the Staff.[170]

The Commission summarized DTE's argument:

> In exceptions, DTE Electric notes that the Staff found value in the DFA project for ratepayers and the environment. 8 Tr 4191. The utility contends that the project will lower power supply cost recovery (PSCR) costs and reduce solid waste. DTE Electric states that it "has received internal project

[170] See May 2, 2019 order, pages 6-7.

approval and has completed benchmarking and conceptual design of the project." DTE Electric's exceptions, p. 4; 4 Tr 600.[171]

The Commission then adopted the findings and recommendations of the ALJ, excluding the projected expenditures from rate base:

> The Commission adopts the findings and recommendations of the ALJ. DTE Electric failed to show full internal budgetary approval for this project. 4 Tr 600. Like the Staff, the Commission is supportive of the goals of the DFA project, but the Staff's proposed disallowance is reasonable in light of the fact that the company failed to provide sufficient information to the Staff to allow for a thorough analysis of the NPVRR, and could not demonstrate corporate approval for the expense.[172]

Against this backdrop, the Attorney General and ABATE take issue with DTE's projections in this case. The projected costs for the Monroe coal ash basin closure are discussed in subsection i), while the projected costs for the Monroe fly ash conversion project are discussed in subsection ii).

i. Monroe Coal Ash Basin Closure

DTE's Schedule B5.1, page 2, line 13, reports 2018 capital spending of $1.6 million and projects capital expenditures to clean close the Monroe Ash Basin of $19.9 million in the bridge period and $20.9 million in the test year. In his direct testimony, Mr. Morren provided the following explanation:

> Line 13 (Monroe Bottom Ash Basin Closure (CCR)) represents a project to remove all bottom ash from the inactive bottom ash basin at Monroe Power Plant to meet the EPA's CCR requirement. This project includes engineering, road and bridge upgrades, and associated trucking to support transporting approximately 2 million cubic yards of bottom ash from the Monroe inactive bottom ash basin to Sibley Quarry.[173]

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[171] See May 2, 2019 order, page 7.
[172] See May 2, 2019 order, pages 8.
[173] See 5 Tr 595.

Mr. Coppola recommended that the Commission reject DTE's proposed expenditures for the Monroe Bottom Ash Basin closure, characterizing them as premature in light of recent regulatory changes:

> The CCR requirements emanate from the Resource Conservation Recovery Act (RCRA). However, with the enactment of the Water Infrastructure Improvements for the Nation (WIIN) Act of 2016, utilities can develop alternative CCR compliance programs working with state agencies. According to a discovery response from the Company on this matter, the Company stated that the Michigan Department of Environment, Great Lakes and Energy (EGLE) is working with Michigan utilities and other stakeholders to develop of a state program. Although there may be some similarities between the EPA compliance rules and the rules promulgated by EGLE, it is premature to spend over $40 million over the next two years and four months for a program that still may change and has no definitive rules set by the state agency.[174]

Mr. Coppola also cited Consumers Energy testimony from Case No. U-20134.

Ms. York objected to the proposed expenditures for the basin closure and also the dry fly ash conversion project. Regarding the basin closure project, she recommended that all projected expenses be rejected, and in the alternative, that only $4.13 million for the bridge period and $7.77 million for the test year be included in projected rate base.[175] She based her review in part on DTE's response to a Staff audit request included in her Exhibit AB-8, which she refers to as PMP documents from the project numbering system used. From this response, she determined that although DTE estimated a total cost of $80 million to remove the CCR material from the Monroe bottom ash basin and test and certify it is clear of CCR material, DTE's Board of Directors had not approved the project, with September 2019 as the targeted date for such approval:

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[174] See 9 Tr 2995.
[175] See 7 Tr 1938-1939.

> As shown in the PMP documents provided by DTE in support of this project, DTE was targeting September 2019 for full BOD approval. However, as of the filing date of this testimony, DTE has not provided any updates, via supplementary audit responses, or otherwise, on the status of full BOD approval of its anticipated capital expenditures associated with this project. If the BOD has not approved DTE's requested capital expenditures for this project, then I recommend disallowing it in this case.[176]

Explaining her alternative recommendation to include partial funding, she testified that the PMP documents in Exhibit AB-8 identify 2019 expenditures totaling $2.8 million, and 2020 expenditures of $4 million, with the remaining $74 million of projected costs assigned to "future years."[177] Her Table 4 compares these amounts to the amounts included on page 2 of DTE's Exhibit A-12, Schedule B5.1. In formulating her alternative recommendation, Ms. York calculated total bridge period capital expenditures using the 2019 value of $2.8 million, plus one-fourth of the 2020 value of $ 4 million to get bridge period capital expenditures of $4.13 million. She calculated her recommended test year capital spending of $7.77 million by prorating the remaining $74 million estimated for the project over the 58-month time period for DTE to complete closure, according to its documentation, plus the remaining three-quarters of the 2020 spending.[178]

In his rebuttal testimony, Mr. Morren responded to Mr. Coppola by citing a discovery response DTE provided, now Exhibit A-39, Schedule DD3, stating that State permitting requirements must be as stringent as federal requirements. He also testified that a draft rule released in November 2019 by the EPA would require closure activities to be initiated by August 2020 rather than October 2020.[179]

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[176] See 7 Tr 1940.
[177] See 7 Tr 1941.
[178] See 7 Tr 1942, and footnotes 32 and 33.
[179] See 5 Tr 649-650.

Additionally, Mr. Morren acknowledged that Board of Directors approval had not yet been received, but testified it is expected on December 4, 2019. He also objected that Ms. York's adjustments overlooked what he characterized as 2 "complimentary projects" included in line 13 of Schedule B5.1. He cited PMP 11932 as an example.[180] He also reiterated his rebuttal testimony, discussed above, that "project approval documents do not necessarily reflect the Company's latest forecast," and "[t]he Company's management team reviews and approves the rate case testimony and capital requests, which reflect the most up-to-date forecast at the time."[181]

In her brief, the Attorney General cites Mr. Coppola's testimony and argues:

> As noted, the AG's concern is that the program may change and that there are no definitive rules set by the state agency. Until EGLE issues new compliance rules that have been approved by the EPA, the AG feels that it is premature to spend millions of dollars on this project. Therefore, the AG recommends that the Commission remove the projected capital expenditures of $40,785,000 for this project for 2019 and through the end of April 2021 from this rate case.[182]

In its brief, ABATE relies on Ms. York's testimony. In its reply brief, citing Exhibit AB-8, page 19, ABATE argues that closure need only be initiated in 2020, but need not be completed until October 31, 2025, with extensions available under certain circumstances.[183] ABATE notes that the project approval documents show $74 million are expected to occur in years beyond 2020, and these documents do not specify exactly which years: "As the project is not required to be completed until October 2025, and it is uncertain whether DTE has received all internal project approvals, it is premature,

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[180] See 5 Tr 651-652.
[181] See 5 Tr 652.
[182] See Attorney General brief, page 74.
[183] See ABATE reply, page 21.

unreasonable, and imprudent to include the $40.785 million capital expenditure in rates at this time."[184] ABATE cites the Commission's order in Case No. U-20162 in support of its argument that the Commission has historically disallowed projected expenditures that have not yet received all internal budget approvals.[185]

ABATE also responded to Mr. Morren's rebuttal testimony addressing ABATE's alternate recommendation that the Commission approve only a portion of the projected spending, noting Mr. Morren's rebuttal assertion that Ms. York overlooked complementary projects:

> Of the five complementary projects identified by DTE, however, only two had project approval documents that specifically showed projected capital expenditures occurring during the bridge period and test year in this case. (7 Tr 1941, Table 4; Exhibit AB-8 at 12-15, 19- 21.) As such, these were the only two projects which could reasonably be considered "complimentary." ABATE included those two projects in its analysis and alternative recommendation.[186]

For the reasons explained by the Attorney General and ABATE, this PFD agrees that DTE has not established that it will make the projected expenditures according to the timing reported in Schedule B5.1 of Exhibit A-12. Mr. Morren acknowledged on cross that closure does not need to be completed in 2020, either using the October date in the current rules or the August date in recently-filed proposed rules, but is required to be completed by 2025, with extensions available under certain circumstances.[187]

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[184] See ABATE reply, page 22. ABATE also suggests that DTE could have provided a statement regarding the expected formal approval of the project in its brief in this matter, see ABATE reply, page 21, but the ALJ considers that for DTE to present factual information not included in the record in this case would be improper, without a motion to reopen the record.
[185] See ABATE reply, page 21.
[186] See ABATE reply, page 22.
[187] See 5 Tr 749; also see Exhibit AB-8, page 12.

The unsigned PAT at page 19 of Exhibit AB-8 projects a total project expenditure of exactly $80 million. Under the Brief Project Scope Summary, it recites the following tasks: "1. Perform geotechnical analysis and engineering for closure by removal. 2 Excavate and dredge CCR material. 3. Test and certify that the basis is clear of CCR material." There is no cost breakdown for each of these significant undertakings, and no timeline. The $80 million project cost has only $2 million allocated to 2019, $4 million allocated to 2020, and the remaining $74 million allocated to "future years," as Mr. Coppola and Ms. York testified. In the limited cost detail, the line item for "contract labor" recites a total of $59.4 million, yet DTE presented no contract to account for these costs.

A related project document in Exhibit AB-8 Mr. Morren seemed to be referring to in his rebuttal testimony shows that DTE was planning to spend $800,000 in 2019 for an evaluation of the Area 15 CCR impoundment, confirming the preliminary nature of DTE's proposed spending. That project document, page 12 of Exhibit AB-8, states "Based on recommendations by Fossil Generation and EM&R, the Risk Management Committee (RMC) made the decision to pursue closure by removal, with trucking being the choice of transportation, and disposal of CCR material at Sibley Quarry." Under "problem statement," this document states: "The volume of CCR material and depth of ground contamination is not currently known. In addition, logistics requirements have not been determined, and whether the current on-site road and bridge infrastructure can sustain." Among the tasks listed in the Summary of Scope for this project: "Determine Rough Order of Magnitude (ROM) project cost to perform closure by removal for Area 15." While the second page of this form, page 20 of Exhibit AB-8, indicates that the timeline for seeking

Board approval is targeted for September 2019, Mr. Morren's testimony as discussed above shows that timeline was not met.

Thus, this PFD recommends that the projected costs be excluded from rate base, with the exception of the $800,000 projected engineering expenditure. As discussed below, this PFD also recommends that the Commission follow Dr. Letendre's recommendations to begin tracking and planning for CCR closure costs, either through rate cases as he recommended or outside the context of a rate case, as part of a comprehensive effort to monitor what are predicted to be substantial environmental compliance costs over the next couple of decades, as discussed in subsection d below.

ii. Monroe Dry Fly Ash Conversion

DTE's Exhibit A-12, Schedule B5.1, page 2, line 4, reports capital spending of $1.4 million in 2018, and projected spending of $18.4 million in the bridge period and $55 million in the test year for the Monroe Dry Fly Ash Conversion project. Mr. Morren provided the following explanation in his direct testimony:

> The EPA's fly ash Effluent Limitation Guidelines (ELG) rule promulgated in 2015 no longer permits liquid discharge from fly ash wastewater systems effective December 31, 2023. Conversion to a dry fly ash transport system will require installation of new systems to pneumatically transport ash from each generating unit's precipitator to new storage silos.[188]

Ms. York also recommended that the Commission exclude projected expenditures for DTE to convert the existing wet fly ash transport system to a dry system to meet federal

[188] See 5 Tr 593.

EPA effluence limits.[189] She based her recommendations on her review of supporting documentation DTE provided in response to a Staff audit request, pages 7 and 8 of her Exhibit AB-8. She testified that these documents indicate construction is not expected to begin until after the projected test year in this case, also citing Exhibit AB-9, a confidential exhibit. On this basis, she testified that the project will not be used or useful in the test period and all capital expenditures should be disallowed.[190] She also testified that the documents show DTE is still awaiting Board of Directors approval for the project.

As an alternative recommendation, if the Commission determines it is appropriate to include some level of capital expenditure for this project in rate base at this time, she recommended that a bridge period capital expense amount of $11.47 million and a test year capital expense amount of $34.8 million. She explained that these figures are based on the annual cost projections in DTE's project documents: $4.14 million in 2019; $22 million in 2020, $60.4 million in 2021, with an additional $62.46 million to be spent "in future years." She presented a comparison of these amounts to the amounts included in DTE's projected rate base in Table 3 of her testimony.[191] Her alternative recommended bridge period amount of $11.47 million includes $4.14 million for 2019, plus one-third of $22 million (four months of spending) or $7.33 million for 2020. Her alternative test year amount of $34.8 million includes the remaining two-thirds of the 2020 value, plus one-third of the 2021 value of $60.4 million (four months of spending) or $34.8 million.[192]

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[189] See 7 Tr 1933-1938.
[190] See 7 Tr 1934.
[191] See 7 Tr 1936.
[192] See 7 Tr 1937 and footnotes 24 and 25.

In his rebuttal testimony, to address Ms. York's testimony that the construction would not be used and useful in the projected test year, Mr. Morren cited Ms. Uzenksi's direct testimony in explaining that Construction Work in Progress (CWIP) is included in utility plant for ratemaking purposes, and that the expenditures required to design, engineer, and procure materials during the projected period of this rate case will be recorded to CWIP until the project is placed in service.[193] He also testified that Ms. York's alternative recommendations overlooked 2 "complimentary projects" included in line 4 of Schedule B5.1 and in the company's response to Staff's audit request, Exhibit AB-8. Again, he repeated his contention that the supporting documents do not reflect the most up-to-date forecasts which are presented to the management team as part of its rate case review.[194] DTE's brief argues that Mr. Morren's projected expenditure should be adopted.

In its brief, ABATE relied on Ms. York's testimony. In its reply brief, it further addressed Mr. Morren's rebuttal testimony in response to DTE's brief, arguing that DTE did not establish it received internal approval for the expenditures, and has not claimed that the project will be used and useful within the projected test year.[195] As above, ABATE argues that projects that have not received internal approval should be disallowed consistent with the Commission's decision in Case No. U-20162. And ABATE notes that its alternative recommendation is based on the spending amounts contained in the project approval documents for two related projects, taking issue with Mr. Morren's assertion that it ignored complementary projects.[196]

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[193] See 5 Tr 653.
[194] See 5 Tr 654.
[195] See ABATE brief, pages 23-24.
[196] See ABATE brief, page 24.

This PDF finds that DTE has failed to establish a reasonable and prudent spending plan for the dry ash conversion system at Monroe. A shown in Exhibit AB-8, DTE has an unsigned PAT form for this project with an projected expense total of exactly $149 million, with spending assigned to 2019, 2020, and 2021 of $4.1 million, $22 million, and $60.4 million respectively, and the remainder to reach the $149 million total assigned to "future years."[197] The costs are not broken down into any components or schedule for engineering, procurement, or construction. Exhibit AB-8, page 11, under the heading "included in scope" states: "Engineer, procure and construct a complete and independent dry fly ash collection system." The total project cost estimate reports $103.7 million attributable to "contract labor," but DTE has presented no contract to support this. While the information DTE provided in Exhibit AB-8 stated that Board approval to proceed is expected by December 2019, and "Construction is assumed to start mid-2020," there is nothing to suggest that DTE's planning has progressed to the point where construction beginning mid-2020 would be feasible. While Mr. Morren testified that "related projects" were included in Exhibit AB-8, the only projects in addition to the closure documents discussed above are for a groundwater mitigation plan with spending of $244,000 for 2018 only, and investigatory work for the closure activities with spending of $800,000 in 2019, as discussed above.[198]

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[197] See Exhibit AB-3, page 9.
[198] See Exhibit AB-8, pages 15-18.

d. Future CCR Costs

MEC argues that the Commission should require DTE to provide a full accounting of its current and expected future costs associated with CCR in its next rate case filing.[199] After identifying CCR as one of the largest sources of industrial waste generated in the United States, known to contain toxic materials including mercury, cadmium, and arsenic, Dr. Letendre testified that DTE currently owns and operates 10 CCR impoundments and landfills that it will eventually be required to close.[200] Citing discovery responses from this case and from DTE's IRP case, Case No. U-20471, many of which are included in Exhibits MEC 47 through MEC-54, Dr. Letendre testified that although DTE has provided initial planning estimates of the cost to close some of its active sites, as well as the inactive Monroe Fly Ash Basin, DTE does not know yet what closure activities are required, has not yet provided cost estimates for active landfills at Range Road, Sibley Quarry, or Monroe, and has not developed cost estimates of closure obligations for any of the sites.[201] Citing DTE's statement that it cannot determine the amounts collected from ratepayers for CCR site closure because it uses a compound depreciation rate by plant,[202] Dr. Letendre expressed the concern that by failing to account for money collected from ratepayers toward CCR site closure costs, DTE risks overcharging ratepayers:

> DTE has stated that its depreciation rates currently cover a portion of CCR closure costs, but the Company claims it does not know how much it has collected. This means that when the impoundments close DTE will have no accounting of how much ratepayers already contributed and how much remains to be recovered through rate base, an environmental rider, or other mechanism (if recovery is allowed). The risk here is that the entire project

[199] See MEC brief, pages 44-47.
[200] See 9 Tr 3789-3790.
[201] See 9 Tr 3789-3792.
[202] See Exhibit MEC-54.

> cost will again be passed on to the ratepayers, even though ratepayers have already been paying for the CCR project as part of the depreciation expense in their rates.[203]

He recommended that the Commission require DTE to present a full accounting of its current and projected CCR costs in its next rate case filing, along with a description of how the company plans to cover these costs in future years. The accounting details he identified include: historical and projected test rear CCR costs (both capital and O&M); projected O&M, closure, and post-closure costs for each CCR facility, along with a projected timeline of when such costs will be incurred; and funds collected to date that have been earmarked for CCR-related costs.[204]

DTE opposes the MEC Coalition's recommendation. In his rebuttal testimony, Mr. Morren identified uncertainty in the current CCR environmental requirements:

> Under the Resource Conservation and Recovery Act (RCRA), the EPA published the CCR rule in April 2015 with an effective date of October 19, 2015. The EPA also revised the CCR rule in October 2016. On July 17, 2018, the EPA issued a new rule that provided provisions allowing State-approved programs flexibility in groundwater monitoring requirements, among other things. State programs must be approved by the EPA and must be as stringent as the federal rule. Although much of the original rule remains unchanged and in place, a 2018 court decision addressed issues raised by both Industry and Environmental petitioners and required the EPA to revisit elements of the CCR rule. EPA issued a pre-publication draft rule in response to this decision in November 2019. The draft rule is expected to be published in the Federal Register soon and is not expected to become final for several months. The rule may change during the EPA's review of public comment and finalization of the rule. EPA is also expected to propose additional CCR rules in the near future.[205]

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[203] See 9 Tr 3793.
[204] See 9 Tr 3793.
[205] See 5 Tr 660.

He presented a link to website to show that DTE is providing information on the company's plans publicly, but acknowledged that due to uncertainties in the CCR regulations, it is not fully known what will be required. He stated that DTE would request approval of projected expenditures in rate cases, and characterized Dr. Letendre's recommendations as premature:

> The Commission should find Witness Letendre's recommendation is premature. Without the CCR regulations being completely final, the Company does not fully know the requirements that need to be satisfied nor the complete expenditures associated with meeting the uncertain requirements, so any relevance to the Company's rates is indeterminate.[206]

This PFD recommends that the Commission adopt Dr. Letendre's recommendation. The costs DTE presented in this case are a case in point. DTE proposes capital expenditures of at least $225 million to address CCR issues at Monroe alone, as shown by the preliminary estimates in Exhibit AB-8, yet did not in its direct testimony present any comprehensive overview of the projects or total project costs, only identifying the yearly spending through the projected test year in this case with minimal explanation. No timelines or cost breakdowns were presented that would indicate separately the timing and cost of engineering studies, the projected costs of construction, the required environmental approval processes, etc. In addition, a note on the closure documents for Monroe indicates that "engineering or construction pertaining to the process waste water (chem ditch) project" is excluded from the closure project scope, and is "to be addressed under a separate project."[207] Since ratepayers will be asked to foot

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[206] See 5 Tr 661.
[207] See Exhibit AB-8, page 21.

the bill for substantial costs over the years to come, with some costs presumptively included in the cost of removal used to set depreciation rates, it is reasonable and appropriate for the Commission to begin monitoring the current and potential costs.

e. Belle River Retirement Analysis

The MEC Coalition also asks the Commission to require DTE to perform an updated retirement analysis for Belle River, comparing retirement dates in 2025/26 to 2029/2030. Dr. Letendre testified that DTE's projected routine capital costs for the bridge and test year total $103.5 million, which he calculated to be three times the spending level from the historical test year.[208] Citing DTE's recent IRP, Case No. U-20471, he testified that DTE's recent analysis found only a $39 million NPVRR from continuing to operate the plant through 2029-2030. After further reviewing the issues in the IRP, he recommended that the Commission require DTE to provide a thorough analysis of capital spending plans for Belle River units 1 and 2 under a 2025-2026 retirement scenario as well as under a 2029-2030 retirement scenario, with an evaluation of the most economic retirement date(s) for the units.[209]

DTE objects to the MEC Coalition's recommendation. Ms. Crozier testified that DTE objects to performing this analysis. She testified that the underlying planning principles are part of DTE's IRP planning process, and further opined that DTE demonstrated in its IRP case that continuing to operate Belle River until 2029/2030 is favorable to customers. Characterizing the analysis as "not a reasonable diversion" in a

[208] See 9 Tr 3784.
[209] See 9 Tr 3788.

rate case,[210] she believes retirement scenarios should continue to be addressed in IRP proceedings

> The IRP is a complex, extensive and heavily litigated process that considers the Company's overall generation portfolio. In recommending the Company present an updated Belle River retirement analysis, Witness Letendre is attempting to litigate the Company's IRP in a rate case forum. Witness Letendre is also attempting to move the future rate case into a scenario analysis event. The Company's rate cases are about normalized historical costs adjusted for known and measurable changes to arrive at a one-year projected test period. If the Company were to file a rate case in 2020, the Company would be providing expenditure information for planned retirements 9-10 years in the future to meet Witness Letendre's request, which would be well beyond the forecasted test period in that case.[211]

She further expressed a concern that granting this request would lead to multiple requests from other parties.

DTE did not directly address Dr. Letendre's recommendation in its brief. In its reply brief, characterizing the MEC Coalition's argument that the Commission should adopt this recommendation as a suggestion, DTE objects to providing a retirement evaluation for the reasons stated in Ms. Crozier's rebuttal testimony, focusing on the existence of the IRP process and the use in rate cases of a 12-month projected test year.[212]

This PFD finds that the MEC Coalition's request is reasonable and should be adopted. While DTE is obligated to file Integrated Resource Plans every 5 years, it is also obligated to establish the reasonableness and prudence of expenditures it seeks to recover in annual rate case filings. MEC's requested analysis of a 2025/2026 retirement date would fall within a five-year time frame of the expected filing of DTE's next rate case,

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[210] See 4 Tr 508.
[211] See 4 Tr 507-508.
[212] See DTE reply, pages 16-17.

which might be expected to use a test year ending in 2022. A five-year planning period for a rate case is not extraordinary. DTE has to present a five-year plan in PSCR proceedings, and in Case No. U-18014, the Commission required DTE to prepare a five-year distribution plan. DTE recovers its capital investments over a period years, using depreciation rates established periodically in depreciation cases. It is not unreasonable to expect DTE to justify any major capital investments in a plant as economical over the remaining expected life of the investment. Put another way, should conditions change following an IRP plan, DTE may not simply stick its head in the sand in reliance on a determination made in that case, without further considering ratepayers interests in light of current conditions. In its February 20, 2020 order in Case No. U-20471, the Commission addressed the retirement analysis DTE presented in that case:

> The Commission agrees with the intervenors and the ALJ that the retirement analysis for Belle River provided with the company's filing is inadequate and fails to demonstrate that the 2029/2030 retirement scenario is reasonable and prudent. As such, the Commission directs DTE Electric to provide additional retirement information pursuant to Section 6t(5)(k) and (m) as part of its next IRP filing. This information would take into account any changes in environmental laws or formally proposed changes to environmental laws which have occurred in the interim, particularly with respect to effluent limitations guidelines and environmental retrofits. This information shall also include NPVRR analyses, with and without the environmental capital expense and operations and maintenance (O&M) costs discussed in this proceeding and in several rate cases, in order to provide the Commission with additional information on the reasonableness and prudence of planned investments, in several different proposed retirement years including 2024/2025. In the meantime, the Commission will continue to carefully scrutinize near-term capital expense and O&M costs as part of the economic analysis necessary to making these investment and cost recovery decisions in rate cases. The Commission stresses the urgency of this issue given the timeline for environmental expenditures. Exhibit A-13; 5 Tr 1123, 1159-1161. As the Commission has not found the proposed 2029/2030 retirement date to be reasonable and prudent, there is

> explicitly no presumption of reasonableness and prudence involving additional expenditures needed to keep the plant running.[213]

In order to properly evaluate projected capital and O&M spending in future rate cases, DTE is clearly going to have provide an economic analysis supporting continued operation of the unit, i.e. the retirement analysis requested by the MEC Coalition.

4. Distribution Plant (Exhibit A-12, Schedule B5, line 7; Schedule B5.4)

As shown on line 7 of Schedule B5 in Exhibit A-12, DTE projects bridge period distribution spending of $1.13 billion and projected test year spending of $854 million, for a total of approximately $2 billion. DTE categorized its costs first into two program types, base and strategic, and then into subcategories within those program types as shown in page 1 of Schedule B5.4 of Exhibit A-12. As also shown in that schedule, the Commission has authorized the creation of a regulatory asset for Advanced Distribution Management System (ADMS) costs.

Mr. Bruzzano presented testimony in support of DTE's capital spending, while Ms. Robinson also testified in support of DTE's projected AMI-related spending. These figures do not include projected O&M spending, or the surge spending approved in Case No. U-20162, which are discussed in section VII below.

a. Background

As background, the Commission established a requirement that DTE submit five-year distribution system plans in its January 31, 2017 order in case No. U-18014. In that case, the Commission explained its concerns:

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[213] See February 20, 2020 order, pages 37-38.

While the Commission declines to adopt the Staff's general disallowance, the record in this case indicates: (1) DTE Electric is in fact spending in excess of the amounts allocated for distribution; and (2) despite this investment, there is little or no improvement in the company's reliability metrics. See, 3 Tr 287-288. And although the company insists that it intends to address company-wide reliability issues proactively, as the ALJ pointed out, the reliability programs that the company chose to highlight are also ones where spending is not projected to increase or may decrease. PFD, p. 87, discussing Exhibit AG-17. *The Commission agrees with DTE Electric's goals to proactively engage in increasing system resiliency and replace aging equipment but observes a disconnect in how funds are allocated and presented for cost recovery purposes. As measured* **by** *dollars spent, DTE Electric's actual investment priorities are new business, load growth, and reactive equipment replacement in response to outages. As was highlighted in the PFD, pp. 102-103:*

> *A key concern raised by DTE's evidentiary presentation in this case is that DTE finds it acceptable to displace spending on reliability projects for which it received ratepayer funding with spending for new business and load growth as well emergency repair. Also, a review of Mr. Whitman's Schedule R2 of Exhibit A-28 shows that although DTE's 2015 actual distribution capital spending was $10 million more in 2015 than it projected in Case No. U-17767, the spending for the "system strengthening and reliability" line items were $30 million below the rate case projection while "new business" spending was $30 million more than projected. Mr. Whitman's schedule M8 of Exhibit A-21 also shows DTE's view that its ratepayer funding for distribution operations is fungible, essentially stating that DTE will spend all distribution operations capital amounts included in rates in this case on load growth and new business before spending it on reliability programs.*

The Commission observes that DTE Electric's evidentiary presentation included a high-level overview of distribution capital drivers and needs with examples and anecdotes about the age and condition of certain system components (e.g., breakers), infrastructure costs by category (new business, emergency repairs, major equipment, etc.), and summary results of localized pilots. 3 Tr 355. While not a holistic and detailed presentation of near- and longer-term distribution system conditions and upgrade needs, this evidence provides the Commission a glimpse into the potential need for significant investments in the coming years just to avoid further decline in system performance and to keep in check the associated spending on reactive repairs and O&M expense of managing aging infrastructure. As DTE Electric pointed out, as its system continues to age, the cost to simply maintain the status quo are projected to go up and there is increased

> potential for equipment failure that could affect reliability and the safety of employees and the public at large. DTE Electric's initial brief, pp. 45-46.[214]

Expressing its support for the authorization of necessary investments to ensure the utility's distribution system is safe, reliable, and resilient, the Commission determined that "the rate case process would benefit from the company providing a more comprehensive, forward-looking capital investment and operations plan." It thus required DTE to submit a five-year distribution investment and maintenance plan:

> 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.[215]

The Commission further explained its rationale for requiring this plan:

> 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.
>
> Given the additional information that the Commission anticipates will be provided through the distribution plan and related review, the Commission finds that it would be premature to adopt the ALJ's recommendations to

[214] See January 31, 2017 order, pages 39-40 (emphasis added).
[215] See January 31, 2017 order, pages 40-41.

implement a tracker or open a proceeding to investigate the potential for improving DTE Electric's distribution system.[216]

As the discussion that follows will show, the record in this case reflects a repetition of the same pattern that led to the Commission's decision as quoted and highlighted above, except that the prefunded amounts that DTE did not spend on system reliability in 2018 were significantly greater than the amounts discussed in Case No. U-18014.

DTE witnesses Bruzzano and Robinson presented primary testimony for DTE in support of its projected distribution system capital expenditures. In his testimony in support of DTE's historic test year and projected capital expenses, Mr. Bruzzano explained the organization of DTE's Distribution Operations into 10 organizations, and he provided overview statistics regarding DTE's distribution system, by component, age, and geographic distribution. He also provided statistics assessing DTE's system performance, including System Average Interruption Duration Index (SAIDI) statistics, both including and excluding Major Event Days (MEDs). He provided the following explanation why DTE's SAIDI measure has been in the fourth quartile for the last several years:

> It is because of a combination of factors the Company seeks to address though the Investment & Maintenance plan presented in this case. These factors include the tree trimming backlog that must be addressed to achieve a five-year cycle, the aging infrastructure which leads to equipment failures, the need for additional capacity to address overloaded substations and circuits and to provide redundancy in the event of failures, and gaps in technologies that allow grid monitoring and remote operations for improved restoration.[217]

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[216] See January 31, 2017 order, page 41.
[217] See 4 Tr 129.

Mr. Bruzzano also explained DTE's cost categories for distribution system expenditures and explained both generally and more specifically why actual capital spending varies from forecast amounts. At a general level, he testified:

> Variation can be expected from forecasted amounts for a variety of reasons. The most significant variations are driven by weather, as the Company's projections for Emergent Replacements are based on a five-year average. The Company does not have discretion in responding to weather events that cause power outages or damage to the electrical system. Other reasons can include permitting and right-of-way delays, changes in customer requests for service, shifts in the expected timing and location of development, and changes to labor and material costs in response to regional, national and global economic trends.[218]

At a more specific level, he presented Table 6 at 4 Tr 132 to compare 2018 actual capital expenditures to DTE's 2018 forecast in Case No. U-20162. He testified that overall, DTE invested $22.3 million more than what was forecasted in the prior rate case, which he attributed mostly to higher than projected emergent replacements.[219] He testified that partly in response to the overspending in emergent replacements, there was a reduction in spending for Strategic Capital Programs, "though it is important to note that there were other factors that contributed to the underspending in this category."[220]

Mr. Bruzzano also specifically discussed DTE's grid modernization efforts, explaining that DTE engaged the Electric Power Research Institute (EPRI) to assess the investment plan in this case and in its current five-year plan, presenting EPRI's report in Schedule M9 of Exhibit A-23. He testified that the five-year plan included in this case is an evolution of the detailed plan DTE submitted in January 2018 in Case No. U-20147.

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[218] See 4 Tr 130.
[219] See 4 Tr 131.
[220] See 4Tr 132-133, also citing Schedule M1 of Exhibit A-23.

Mr. Bruzzano also testified that DTE's next five-year plan is due in June 2020, citing the Commission's order in Case No. U-20147, but in his rebuttal testimony, seemed to acknowledge that the correct date is June 2021.

Several witnesses expressed concerns with DTE's proposed spending, with not all the parties' concerns tied to specific rate case expense projections. Staff generally supported the company's projections, but took issue with AMI-related spending in the technology and automation category. The general concerns raised by the parties are explained in subsection b below, while issues involving specific cost projections are addressed in subsection c, followed by a discussion of other requests for specific Commission actions, including performance-based ratemaking and reporting requirements.

b. General Concerns

ELPC raised concerns with DTE's distribution system planning and projected spending, but did not recommend any specific adjustments. ELPC witness Villareal began his testimony by noting DTE's plans to spend $2 billion over the bridge period and test year in this case. He also noted that he had provided testimony in DTE's last rate case, testifying to his view that DTE's distribution system plan still remains too focused on short-term capital costs, does not adequate plan for distributed energy resources (DER), and does not adequately consider non-wires alternatives (NWA) to meet reliability needs and customer demand. After reviewing the distribution system planning process initiated by the Commission in Case No. U-20147, and reviewing key findings of the Staff's report in that docket, Mr. Villareal testified that DTE's plan lacks several of the components Staff specifically requested in its reports.[221] He expressly disputed Mr. Bruzzano's testimony that DTE's investments reflect guidance from the Commission's November 2018 order in that docket, and provided examples including the absence of a description of how it uses dynamic system load forecasting, the lack of a model cost-benefit analysis framework, the lack of explanation for replacement/upgrade criteria, and the lack of details related to a workforce adequacy plan.[222] Mr. Villareal also expressed a concern that DTE has not met the need Staff recognized for more transparency and stakeholder outreach.[223]

Mr. Villareal highlighted the rationale for attention to the distribution system, testifying that the investments the utility will make in this proceeding will be in place for years to decades. In his view, DTE's proposed investments in this docket "remain unmoored to a longer-term vision," and "follow largely the same script they have been following for years –focusing on immediate capital projects without a clear identification of how those investments support a longer-term vision for integrating DER."[224]

Mr. Villareal expressed a concern that DTE may not spend the funding it requests in this case as proposed:

> Mr. Bruzzano notes in his testimony that DTE retains flexibility to use funding for other projects, including those identified in the "Emergent Replacements." The Emergent Replacement program covers costs related to storm and emergency events and other unplanned costs. In 2018, for instance, DTE spent only 70% of its projected spending on strategic capital programs, while its spending on emergent replacements was higher than forecasted. DTE's use of funds approved for strategic capital programs on Emergent Replacements needs shows that DTE could do a better job

[221] See 9 Tr 2694.
[222] See 9 Tr 2694-2695.
[223] See 9 Tr 2695.
[224] See 9 Tr 2697.

> budgeting, but also that funding can be taken away from the strategic capital spend and used on other projects. Another concern relates to DTE's identification of tree trimming, yet again, as the number one project to come out of DTE's Global Prioritization Model. No doubt that tree trimming is important and is part and parcel of basic utility functions, but in the context of a distribution system planning process, such as the one I have previously identified, I believe tree trimming misses the point regarding planning for the future electricity system. The Commission should be wary of continually funding this project at increasing levels of funding and surges absent a showing from DTE that it is using funds allocated for tree trimming on actual tree trimming.[225]

Mr. Villareal recommended that the Commission adopt measures to ensure that tree trimming funding is used on tree trimming, suggesting the use of a performance-based metric.

Mr. Villareal complimented DTE for its use of the DSPx framework for planning organization, and for bringing in EPRI as an outside consultant, but expressed a concern that DTE is not using those resources effectively.[226] He agreed with EPRI's and DTE's assessment that it is currently at Stage 1 of a transition to a more modern grid, and expressed a concern that DTE is not adequately considering coordinating the component pieces, such as its communications network:

> In DTE's context, Witness Robinson describes the transition from a 3G network to 4G, and includes a statement that "other grid sensing devices could take advantage of this network," yet provides no examples of a plan for making that happen or whether they are actively testing such capabilities. The examples that are provided by Mr. Robinson focus far more on better utilization of data rather than the broader utilization of the 4G network. Mr. Bruzzano also does not describe how DTE intends to leverage this communications network.[227]

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[225] See 9 Tr 2702-2703.
[226] See 9 Tr 2703-2704.
[227] See 9 Tr 2705.

In recommending that the Commission give no weight to the EPRI report, he explained his concern that the plan "confirms that DTE's plan is consistent with DTE's own objectives," and does not compare DTE's plan to any other utilities.[228]

Mr. Villareal also discussed the concept of interoperability testing at length, testifying that he is generally supportive of investments in SCADA and ADMS, but has concerns with DTE's proposed implementation of ADMS as described by Mr. Bruzzano because he does not believe DTE is adequately considering the value of interoperability testing. He explained interoperability testing with reference to the National Institute of Standards and Technology definition,[229] and more generally with reference to the value of open standards, rather than proprietary standards that may inhibit interoperability. He based his concern in part on a discovery response DTE provided, Exhibit ELPC-2, contending that DTE's understanding of interoperability only captures part of the concern, the ability to exchange information, testifying:

> Without interoperability, the utility risks higher costs via implementation of costly integration layers to allow the exchange of information and ability to understand and act on that information. Those costs ultimately will be borne by customers.[230]

As an example of his concern, he described DTE's plan to have two different teams work on its key pieces of the ADMS implementation.[231] He also provided as an example, DTE's reliance on vendor testing, which he calls first-party testing, and on its own testing of the

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[228] See 9 Tr 2703-2704.
[229] See 9 Tr 2706.
[230] See 9 Tr 2707.
[231] See 9 Tr 2710.

final products, which he calls second-party testing. He recommended independent third-party testing:

> First and second party testing is insufficient because the vendor and the utility have particular interests in their testing regimes, whereas an independent third party is focused on interoperability and conformance without any vested interest. Third party, independent testing and certification is vital to ensuring a neutral party is validating the claims of the vendor and the testing of the utility for compliance and conformance to a standard. Failure to do sufficient integration testing can result in increased costs as the solutions may not ultimately work as expected. If that happens, then the utility (or the vendor) will need to develop an integration layer between the two components and enable their communications.[232]

He explained guiding practices of third-party interoperability testing, and used DTE's Insight program as a counter-example of open standards, asserting that customer access to their usage information "appears to be built on a proprietary standard and model that requires customers to use, and only use, DTE's preferred method."[233]

As the last topic of his testimony, Mr. Villareal expressed a concern that DTE is insufficiently considering NWA, and insufficiently considering non-utility solutions. He discussed the example of New York utilities, which have a procurement process in place for NWA.

MEC Coalition witness Jester also focused on the significant distribution system capital spending proposed in DTE's filing. Noting Mr. Bruzzano's testimony acknowledging DTE's consistent fourth-quartile SAIDI performance, Mr. Jester presented as Exhibit MEC-61 a report he prepared for CUB, testifying that his report shows that

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[232] See 9 Tr 2710-2711.
[233] See 9 Tr 2713.

Michigan as a whole has among the worst reliability performance in the country.[234] He discussed the difficulty in examining DTE's distribution investments in a rate case:

> Distribution systems are made up of many geographical subdivisions and components, making it unworkable for the Commission or intervenors to examine individual investments in the way that investment decisions can be examined through integrated resource planning. Instead, it is necessary to examine policies, practices, and patterns. However, such examinations will still suffer insufficient information, making it particularly important that the utility be held accountable for results.[235]

He further recommended that the Commission consider performance-based ratemaking measures to hold DTE accountable for distribution system reliability, citing the Commission's recent report on performance-based ratemaking. He reviewed the Commission's efforts to examine the effectiveness of DTE's investments to improve reliability dating back to the Commission's order in Case No. U-18014 through its most recent order in Case No. U-20162.[236] While recommending that the Commission "be careful about the level of distribution system spending" authorized in this case, he did not make recommendations regarding any particular expenditures.[237] He did recommend that the Commission recognize the need for performance metrics and corresponding ratepayer protections, and put in place a process to implement them in DTE's next rate case, "as a condition for distribution system spending above base levels that provide maintenance, new connections, and relocations."[238] In particular, he testified:

> I recommend that the Commission order DTE Electric to file the distribution plan itself and a related proposal for "outcome and output-based performance metrics and corresponding ratepayer protections" within 6

[234] See 9 Tr 3809.
[235] See 9 Tr 3809.
[236] See 9 Tr 3810-3813.
[237] See 9 Tr 3813.
[238] See 9 Tr 3813.

> months after the Commission's Order in this case. That case should be filed as a contested case, enabling a searching examination of the results that might be expected from implementing the distribution plan and of the sufficiency of the corresponding ratepayer protections. The Commission should also encourage DTE Electric to engage stakeholders in the development of that proposal, prior to filing it.[239]

Soulardarity witness Koeppel testified to his concern that DTE investments in safety and reliability are inequitable, contending that customers in low-income communities have more dangerous and less reliable service, and that DTE is not allocating proportionally more toward remedying the inequality. Citing a Staff report from Case No. U-20169, included in Exhibit SOU-1, he testified that 8 of 20 downed wire incidents DTE reported from June 2013 through June 2018 occurred in Detroit, and 5 of those resulted in fatal injuries.[240] He also expressed a concern that many low income and people of color communities are served by DTE's 4.8kV infrastructure, which he characterized as "antiquated and less reliable."[241] He also cited cross-examination of DTE's distribution witness Mr. Bruzzano from DTE's last rate case, Exhibit SOU-2, contending that DTE is obligated to provide the same level of safe and reliable service regardless of location. Noting the significant projected distribution system expenditures underlying DTE's proposed rate increases in this case, he testified:

> Safety and reliability are of special concern in this rate proceeding because DTE is once again disproportionately increasing rates on residential ratepayers and low-income ratepayers; rates for residential ratepayers are increasing by 9.1% in general, which is much higher than the proposed rate increases of 2.9% for primary ratepayers and 7.3% for secondary ratepayers. See DTE's U-20561 Rate Case Summary at 3. DTE's rate increases are especially troubling because, while these increases will hit low-income communities and communities of color the hardest, DTE is not

[239] See 9 Tr 3814.
[240] See 6 Tr 1406-1407.
[241] See 6 Tr 1407.

> allocating proportionally more toward addressing the disproportionate safety and reliability problems found in these communities.[242]

He made clear he was not concerned only with Detroit, and explained a research tool developed at the University of Michigan called "EJScreen," which he testified is a mapping tool to help visualize environmental justice impacts in Michigan. He presented several exhibits, including a paper describing the methodology and tool, and illustrative maps, in his Exhibits SOU-3 through SOU-6. He recommended the use of this or tools like this to ensure that infrastructure spending "takes into account the environmental burdens borne by communities, especially because so many of those burdens relate to the energy system, and does not leave these communities behind."[243]

Specifically regarding the 4.8kV infrastructure, Mr. Koepell reviewed Mr. Bruzzano's testimony on modernization versus hardening, concluding from his testimony that while half of the Detroit 4.8kV infrastructure will be hardened, and 25% will be modernized, 25% will receive nothing. He took issue with the calculus underlying DTE's decision-making, contending that DTE does not consider the full range of safety benefits but only reductions in maintenance costs in determining where improvements will be advantageous to customers.[244] In discussing the burdens to customers due to outages, he explained:

> Low-income ratepayers are likely to experience proportionally greater harms from outages than high-income ratepayers. For example, if a low-income ratepayer suffers a power outage and thereby loses a two-weeks' supply of food or medicine because the refrigerator stopped working, replacing that supply of food or medicine will be much harder or impossible for low-income ratepayers. If DTE does not incorporate the proportionally

[242] See 6 Tr 1407.
[243] See 6 Tr 1409.
[244] See 6 Tr 1411.

> higher costs of service and service failures to low-income ratepayers, inequality of service will only be exacerbated in the future.
>
> Additionally, low-income ratepayers spend a higher proportion of their income on energy. See Ex. SOU-9, NAACP Environmental and Climate Justice Program, Lights Out in the Cold: Reforming Utility Shut-off Policies as if Human Right Matter, March 2017, at 9. If these low-income ratepayers also do not receive as large an increase in benefits because of inequities in DTE's plan, then low-income ratepayers are paying for improvements they do not receive.[245]

Mr. Koeppel recommended that DTE allocate more resources in Detroit and other low-income communities and communities of people of color, recommending the use of a screening tool as discussed above, and testifying that basing system upgrades and system hardening on economic and load growth will leave these communities without desperately needed improvements.[246]

Kroger witness Bieber also expressed concerns with the reliability of DTE's service:

> In its filing DTE acknowledges its poor reliability performance. If fact, DTE has consistently been ranked in the fourth (worst) quartile in the industry, based on its System Average Interruption Duration Index (SAIDI) metrics. At the same time, DTE has already received $775 million in authorized rate increases since 2015, the second highest in the nation, and is requesting an additional $351 million rate increase in this case. Providing reliable service is a fundamental responsibility for a utility.[247]

He testified that in addition to high outage rates, Kroger has also experienced numerous single-phase outages, voltage fluctuations and power sag events, which can require equipment to be shut down to avoid the risk of significant and expensive damage.[248] He

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[245] See 6 Tr 1412.
[246] See 6 Tr 1414.
[247] See 8 Tr 2157.
[248] See 8 Tr 2159-2160.

concluded that DTE needs an effective mechanism to incentivize it to improve its reliability performance, and recommended a "Reliability Incentive Mechanism" (RIM) that would provide a credit from DTE to its customers until it achieves at least one year of average or better reliability performance.[249] He recommended that the RIM credit be set at a 10-basis-point differential in DTE's return on equity, which he calculated as $9.4 million based on DTE's projected revenue requirements.[250]

Mr. Bruzzano addressed these myriad concerns to some extent in his rebuttal testimony.

Addressing Mr. Jester's testimony, Mr. Bruzzano objected to his characterization of the Commission's denial of DTE's requested IRM in Case No. U-20162 as a reflection of the Commission's concern that DTE's distribution plan was insufficiently persuasive, quoting the Commission's order at page 20. He cited Mr. Jester's acknowledgement that he is not recommending any particular spending adjustments in this case, and objected to his recommendation that DTE file a revised distribution plan within 6 months of the Commission's order in this case, and include a consideration of performance-based ratemaking, noting that the Commission set a June 2021 date for DTE's next distribution plan filing.[251]

Addressing Mr. Koeppel's testimony, he asserted that DTE focuses its investments to upgrade infrastructure appropriately for safety and reliability, citing Schedule M7 of Exhibit A-23, and disputing that DTE's investments in Detroit are inadequate. He testified:

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[249] See 8 Tr 2160.
[250] See 8 Tr 2161-2162.
[251] See 4 Tr 272-273.

> While approximately 14% of the Company's customers are in the City of Detroit the Company is investing more than 25% of its 2019 strategic capital in the city to address aging infrastructure and improve the safety and reliability of its service, and these significant investments will continue in future years as well.[252]

He described key projects and objected to any alteration in the company's safety and reliability upgrade plan.[253] He testified that upgraded electric service would not drive economic activity.[254]

Addressing Mr. Villareal's recommendations, Mr. Bruzzano testified in support of the EPRI report, focusing on his concern that EPRI did not compare DTE to other utilities, and noting that each utility has a unique system and operating conditions.[255] He also reiterated his view of the value of the DSPx framework. He disputed Mr. Villareal's rejection of DTE's five-year plan, reviewing the history of the plan development and further asserting that the investment strategy and capital expenditures proposed in this case are supported in detail in his direct testimony and exhibits. [256] He also rejected Mr. Villareal's concern for interoperability testing, testifying that because the company is testing all the applications, third-party testing is unnecessary. He disputed that open standards are important, testifying that DTE has agreed to follow the NIST standard of interoperability, but the NIST definition of interoperability does not include "open standards."[257] And he cited his Schedule M6 of Exhibit A-23 to show that the systems included within ADMS are on a common software platform, "with the exception of NMS,"

[252] See 4 Tr 284.
[253] See 4 Tr 283-286.
[254] See 4 Tr 285.
[255] See 4 Tr 273-274.
[256] See 4 Tr 276-278.
[257] See 4 Tr 278-279, 280.

and testified they are fully integrated with the company's GIS and CIS.[258] Also regarding NMS, he testified in defense of a separate project team handling NMS: "Although the NMS project team is a stand-alone team, it is fully integrated with the ADMS project team, sharing resources and subject matter experts and having a fully integrated schedule to track dependencies and risks."[259] He also testified that DTE has plans to perform the full integration testing of AMI data from field devices, which he identified as one of the issues in Maine, and also has already adopted the Green Button solution within the DTE Insight program Mr. Villareal referred to in his testimony: "Currently, customers can access their hourly usage data via the Company's website. By year-end the customer will have the ability to delegate the authority of obtaining their hourly usage data to a third party."[260]

Addressing Mr. Bieber's recommendation, Mr. Bruzzano disputed that DTE needs an incentive to improve reliability, noting that he acknowledged the company's poor reliability performance in his testimony, and further noting that DTE's plan describes extensive plans to improve reliability.[261] He also characterized the RIM as punishing the company, and averred that DTE's June 2021 five-year distribution plan in Case No. U-20147 would contain an update to the company's forecast as to when it will reach average SAIDI excluding MEDs.[262]

In the discussion that follows, recommendations for specific cost adjustments are discussed first in section c, including MEC Coalition's recommendation to increase the

[258] See 4 Tr 279.
[259] See 4 Tr 280.
[260] See 4 Tr 281.
[261] See 4 Tr 281-282.
[262] See 4 Tr 282.

Contribution in Aid of Construction (CIAC), while recommendations for performance-based ratemaking mechanisms are discussed in section d and other recommendations for future rate cases are discussed in e.

c. Projected Costs

As noted above, DTE's projected capital expenditures are summarized in Schedule B5.4 of Exhibit A-12. Mr. Bruzzano testified in support of the projected expenditures. Staff witness Evans testified to Staff's conclusion that DTE's proposed spending is reasonable, with the exception of Staff's recommended adjustment to certain AMI-related costs as explained by Dr. Wang.

As the following discussion shows, Mr. Coppola's recommended adjustments to DTE's projected capital expenditures in the base capital program category primarily relate to the company's use of inflation, and he separately addresses projected spending for the Gordie Howe International Bridge. Within the strategic capital program category, Mr. Coppola's recommended adjustments are related to DTE's chronic underspending in this area, and Dr. Wang's recommended adjustments are related to the technology and automation line item. Also as discussed below, Mr. Jester recommended that the Commission modify the formula for CIAC, increasing the revenue obtained from these contributions.

i. Emergent Replacements

Mr. Bruzzano testified that significant weather events and equipment failures pushed DTE's spending in the emergent replacement category 40% above historical average levels.[263] DTE projected its costs for the three emergent replacements subcategories (storm, non-storm, and substation reactive) using a five-year historical average, in which year's capital spending was adjusted to 2018 levels using an inflation factor, with DTE's proposed inflation factors applied to the resulting average from 2018 through the projected test year.[264] The resulting expense projections are then reduced as shown on Schedule B5.4, page 1 by a $9.1 million savings amount attributed to "strategic spending." Mr. Bruzzano did not explain the full mechanics of this calculation or the savings in his testimony.[265]

The Attorney General took issue with DTE's use of inflation in its capital expense projections, both to "normalize" historical expense levels to 2018 dollars and to project costs through the projected test year. Mr. Coppola testified:

> Although, I understand the Commission decision to allow some adjustment for future inflation impact on costs, the responsibility should still be on the Company to demonstrate that in fact it has experienced inflationary cost increases, and will likely experience inflation cost increases in the future. However, there has been no such evidence presented by the Company in this case or prior rate cases. To the contrary, the Company boasts about having achieved actual operation and maintenance cost levels that are $222 million below the inflation adjusted amounts from 2009 to 2018. This is clear and convincing evidence that the Company has not experienced inflationary cost increases in the past and is not likely to experience them for 2019 and through the end of the projected test year.[266]

As an alternative to excluding all inflation, Mr. Coppola testified that if the Commission decides to use some inflationary cost increases, he recommends using a 2% rate of

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[263] See 4 Tr 133.
[264] See Schedule B5.4, page 3
[265] See 4 Tr 211, 219-220.
[266] See 9 Tr 2974.

inflation, but only for 2020 and the first 4 months of 2021. He presented the calculations for both alternatives in Exhibit AG-1.3.

Mr. Bruzzano took issue with Mr. Coppola's recommendation to exclude inflation in averaging prior year spending levels.

> This is not correct because to properly average these expenditures they must be brought to a constant dollar denomination (in this case they must be expressed in 2018 dollars to form the basis for future projections).[267]

He also presented historical information on CPI increases nationally, and cited Mr. Cooper's testimony on labor cost escalations in DTE's collective bargaining agreements.[268] He also presented a chart to show increases in material costs, and he presented Schedule V2 in Exhibit A-31 to show the CPI rates DTE used in its calculations. He also cited the Commission's recent decision in Case No. U-20162.[269] He reiterated this argument addressing Mr. Coppola's alternative projections for "emergent replacements, new customer connections and new business, and electric system equipment."[270]

The parties' briefs generally follow the testimony of their witnesses.[271]

This PFD finds that it is reasonable to adjust historical experience to a common year (2018) using inflation as the Commission has often done for distribution capital expense categories, and for purposes of this case, this PFD also finds that it is reasonable to project capital expenses in this category using an inflation factor, subject to the

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[267] See 4 Tr 244.
[268] See 4 Tr 246-247.
[269] See 4 Tr 247-248.
[270] See 4 Tr 249-251.
[271] See DTE brief, pages 36-37; Attorney General brief, page 64-66.

incorporation of the savings projected by DTE on line 6 of Schedule B5.4, as well as the recommendation in section VII of this PFD that the Commission require the parties to present either an analysis of actual DTE productivity gains or evidence regarding productivity factors that may be appropriate for use in ratemaking. Nonetheless, this PFD finds that Mr. Coppola's recommended inflation factors are more recent than DTE's and appropriately reflect the CPI-urban index rather than blending a CPI index with a labor rate.[272] As the Attorney General argues, the Commission has rejected the use of a blended rate of the sort DTE relies on in its analysis. However, excluding inflation for 2019 from the calculated values is inconsistent with the normalization approach, so this PFD recommends that inflation for 2019 should be added back to the Attorney General's calculations. Thus, this PFD recommends emergent replacing capital spending of $324,699,000 for the bridge period and $242,250,000 for the test year, which is a capital expense reduction of $3.6 million for the bridge period and $5.1 million for the test year.

ii. Customer Connections

The "customer connections, relocations, and other" subcategory of base capital programs includes five expense line items (connections and new load; relocations; electric system equipment; NRUC and improvement blankets; and general plant, tools and equipment and miscellaneous) as well as offsetting revenue line for CIAC.[273] Mr. Bruzzano presented Schedule M3 of Exhibit A-23 to support DTE's projected expenses for these line items, but regarding the forecast methodology, testified only that DTE use

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[272] As shown in Exhibit AG-1.30, the Attorney General's inflation factors are 1.9% for 2019, 2.1% for 2020, and 1.8% for 2021; the 2021 value should only be applied to the last four months of the projected test year.

[273] See 4 Tr 220.

"2018 actuals plus inflation at a subcategory level, except for the GHIB project, which is forecast based on the project's schedule." Putting aside the GHIB project, which is discussed in subsection iii below, Mr. Coppola again objected to DTE's use of inflation to project capital expenditures for the customer connections subcategories.[274] He testified:

> Although the 2018 capital spending level of New Connections represents the highest amount spent in the past five years by a wide margin, I understand that because of the expanding Michigan economy and the construction activity within the city of Detroit, demand for new customer connections has increased annually. Similarly, for new Business Projects, the 2018 capital spending amount is above the 5-year average but in line with the average amount for the most recent three years. Therefore, I find the 2018 capital spending levels to be reasonable, albeit somewhat high.
>
> As stated earlier, there is no basis for the Company to apply an inflation factor to the 2018 capital spending level to project capital spending over approximately the next two years. Therefore, I recommend that the Commission approve the same amount of capital expenditures incurred in 2018 for future periods, prorated accordingly for stub periods.[275]

Again, as an alternative, Mr. Coppola recommended the addition of a 2% inflation factor, but only beginning with 2020. He presented his calculations in Exhibit AG-1.4 for both alternatives. For reasons similar to the reasons discussed above, although DTE has not identified any savings for these programs as a result of any of its capital investments, this PFD recommends that the Commission include the standard inflationary adjustment for all years, using the Attorney General's projected inflation rates rather than the blended rate adopted by DTE, with the same proviso stated above and addressed further in section VII below. Revising the inflation factors for lines 9, 11, 13 and 15 on page 1 of

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[274] Mr. Coppola did not recommend an adjustment to the NRUC and improvement blankets category.
[275] See 9 Tr 2977-2978.

Schedule B5.4 results in a reduction of $2.4 million for the bridge period and $3.5 million for the test year.

iii. Gordie Howe International Bridge (GHIB)

As shown in line 15 of Schedule B5.4, page 4, DTE reported total capital spending of $10.9 million for the GHIB project in 2018, and additionally projects capital spending of $14.2 million in the bridge period and $3.7 million during the test year. Mr. Bruzzano testified that the project scope had changed since it was determined that DTE's equipment needs to be relocated benefit the from its current location under the road structure at the Point of Entry, to avoid damage due to the company's equipment that would be caused by soil compaction work required to support the new infrastructure.[276]

Mr. Coppola objected to the additional cost, recommending a $9 million reduction in the projected capital expenditures:

> In discovery, the Company was asked to explain why this project will require an additional $18.9 million in capital expenditures, on top of the $10.9 million spent in 2018. In several responses, the Company stated that the scope of the project changed, requiring a budget increase of $18.5 million, of which the Company will be responsible for half. The Company also stated that it originally proposed vacating its facilities from the Port of Entry (POE), but the Windsor Detroit Bridge Authority (WDBA) deemed the plans to be cost prohibitive. Therefore, the Company and the WDBA apparently proceeded with an alternative plan. However, now the parties are finding that soil conditions prevent the location of the DTEE facilities at the originally planned site and relocation to a different site is necessary. Exhibit AG-1.5 includes the Company's discovery responses.
>
> This relocation raises questions about the competency of the original work done and the decision to choose the original location. In addition, this is work specifically required to benefit the WDBA at an extraordinarily high cost, which is now nearly $29 million. The other customers of the Company do not benefit from these capital expenditures. Therefore, any additional

[276] See 4 Tr 161-162.

> costs to relocate the facilities should not be paid by the rest of DTEE's customers by including them in rate base. The entire incremental costs to complete the relocation should be paid by the WDBA. If the Company agreed to pay for half of the incremental costs, then it should absorb those costs and not burden its customers with higher costs.[277]

Mr. Bruzzano objected to the recommended $9 million disallowance. Presenting a picture of the Michigan Bridge Exchange and surrounding environs at 4 Tr 253, he testified that the Bridge authority wanted to reduce the costs of the project by requesting that DTE not relocate its existing equipment from the point of entry,[278] and DTE insisted on a high degree of confidence that its equipment would not be damaged and could be easily accessed. Mr. Bruzzano testified:

> AG Witness Coppola states that "now the parties are finding that the soil conditions prevent the location of the DTEE facilities at the originally planned site and relocation to a different site is necessary." It is important to understand that the Company did not choose an area in which to locate its infrastructure and subsequently changed it. As discussed in my direct testimony on page 45, lines 19-21, the Company evaluated the option of leaving its infrastructure ("facilities") in place underneath the future POE, but determined that they had to be relocated once it became known that its infrastructure would become damaged if it remained in place.[279]

Presenting Figure 3 at 4 Tr 254 to show the equipment that must be relocated, he testified

> The timing of when the need to relocate the infrastructure was identified did not impact the cost of the relocation. The decision to incur the additional cost is reasonable and prudent as it safeguards the integrity of the equipment.[280]

This Commission has already approved expenditures for the bridge relocation, with DTE's commitment that half the funding would come from the bridge authority. The

[277] See 9 Tr 2980-2981.
[278] He testified "by not requesting that the Company relocate its electrical system" at 4 Tr 252.
[279] See 4 Tr 253-254.
[280] See 4 Tr 255.

primary question presented is whether DTE was reasonable and prudent in its expenditures to date, prior to the determination that the plan it was pursuing would not work. Mr. Coppola's concern with the change in scope of work, while appropriate, does not actually answer the question whether DTE's prior expenditures were reasonable, including whether any of those expenditures could have been avoided had DTE known of the soil conditions, and if so, what expenditures. Rather than somewhat arbitrarily limiting DTE to the amount it has already spent, the Commission should demand a more rigorous accounting in DTE's next rate case of the previously spent funds in order to answer that question.

iv. Strategic Capital – Overall Spending

DTE's strategic capital programs cost category includes three line items: infrastructure resilience and hardening, infrastructure redesign, and technology and automation. As shown in Schedule B5.4, DTE spent a total of $280 million on these three line items in 2018, and projects an additional $912 million through the bridge period and test year in this case. Additional detail regarding DTE's projections for these categories are in pages 7-9 of Schedule B5.4 and Schedules M4 through M6 of Exhibit A-23. Mr. Bruazzano described the expenses in this category as follows:

> Strategic Capital programs include investments that are necessary to ensure the long term health of the electric distribution system and the continued ability to serve customers with a high level of reliability and power quality, particularly as economic activity continues to rebound in southeast Michigan and as the distribution system continues to evolve in response to higher levels of DER and EV penetration.[281]

[281] See 4 Tr 147.

DTE generally acknowledges that it underspent by $126 million what it projected in its last rate case it would spend on this category in 2018. DTE argues that the underspending was attributable to greater than average storm activity and other reasons. Mr. Bruzzano testified:

> In some cases, resources that would have been deployed to the Strategic Capital programs had to be diverted to address emergent work. For example, overhead linemen that might have been scheduled to work on circuit conversions would instead have been dispatched to repair broken poles and downed wires caused by high winds or ice damage. In addition, the Company's support for the hurricane restoration efforts in Puerto Rico impacted resource availability. Between December 2017 and May 2018, the Company had 277 employees work nearly 100,000 hours to support the restoration efforts in Puerto Rico. It is extremely important for the Company to support requests for mutual aid, as the Company relies on the support of other utilities during major storms, such as the March 2017 storm and the two catastrophic storms in 2018.[282]

Citing Schedule M1 of Exhibit A-23 as the source of a more comprehensive explanation, he identified additional factors responsible for the underspending:

> These factors included delays in permitting, changes in the timing of projected customer demand growth requiring new substations or substation upgrades, changes in customer need dates, and the need to manage aggregate Company expenditures, which is especially important in years of unusually high Emergent Replacement costs, as was the case in 2018.[283]

Mr. Bruzzano presented a project ranking at 4 Tr 149 and described generally how DTE expects these investments to reduce risk, improve reliability, and help the company manage its costs.[284] He explained DTE's approach to forecasting capital expenditures for this category:

> DTE Electric targets an approximate total level of capital expenditures for its distribution system as part of its prudent management of the Company's

[282] See 4 Tr 136.
[283] See 4 Tr 137.
[284] See 4 Tr 150-154.

> resources and workforce. Wide swings in aggregate expenditures from what is contemplated in the Company's plans could be challenging to manage, both operationally and financially. Therefore, the Company has adjusted its planned level of Strategic Capital to account for the projected increase in Base Capital. Should Base Capital expenditures during the forecast period run below the projection, the Company would accelerate the strategic investments that provide the greatest customer benefits.[285]

He then discussed some of the programs that make up the infrastructure resilience and hardening line item for this category, especially focusing on the system hardening that was a subject of the Commission's order in Case No. U-20162 as well as the focus of testimony by Mr. Koeppel as discussed above, and on pole top maintenance and cable replacement.[286] Within the infrastructure redesign line item, he specifically discussed the subtransmission redesign, City of Detroit infrastructure, and 4.8kV conversion and consolidation projections, the latter of which were also a focus of Soulardarity's concerns as discussed above.[287] For the technology and automation line item, he specifically discussed the ADMS program, SOC modernization, 13.2 kV telecommunications upgrades, distribution automation, and non-wires alternatives (NWA) pilots.[288]

The Attorney General recommended a 20% reduction in DTE's projected capital expenditures for this category: Mr. Coppola cited two DTE discovery responses in Exhibit AG-1.7 as shedding light on DTE's commitment to these programs. In the first, DTE characterized its planned spending for this category as a "goal," and further stated:

> The Company plans to make the investments forecasted in this case *unless unforeseen events, such as the severe weather that led to high levels of emergent replacements in 2018, require resources to be diverted on a*

[285] See 4 Tr 157-158.
[286] See 4 Tr 163-178.
[287] See 4 Tr 178-185.
[288] See 4 Tr 185-211.

> *temporary basis*. The Company expects to continue making progress in its strategic investments and has already done so.[289]

In the second, DTE acknowledged negative consequences arising from its failure to meet its projected strategic capital spending for 2018, while also disputing that ratepayers had "funded" the strategic capital spending:

> Question: Refer to page 38, lines 12-25, and page 39, line 1-2, of Mr. Bruzzano's direct testimony. Please explain if the same negative consequences occurred as a result of the Company reducing the Strategic Capital Investments in 2018 from the levels approved and funded by the Commission in Case No. U-20162.
>
> Answer: DTE Electric objects for the reason that the request is argumentative since the Commission approves rates and not funding levels for specific categories. In further answer, without waiving the objection, the answer is yes. For this reason, the Company plans to execute its full slate of strategic investments, even if unforeseen factors in any given year (such as large storms) cause these investments to be delayed.[290]

Mr. Coppola testified that he reviewed the capital spending for 2019 through September relative to forecast expenditures

> The result of that analysis is that the Company has again significantly underspent its forecasted capital expenditures during the first nine month of 2019 by approximately 21%, and in some categories, such as Technology and Automation, by as much as 32%. Exhibit AG-1.6 shows this comparison based on actual and forecasted capital expenditure information provided by the Company.[291]

Based on this analysis, Mr. Coppola concluded that DTE is not likely to reach the spending levels projected for the strategic capital programs as proposed. He testified:

> The commitment to spend the requested amounts is consistently reneged upon, once other programs require more funding. Weather events occur, to some degree or another, every year and will continue to do so in the future.

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[289] See 9 Tr 2984, emphasis added.
[290] See 9 Tr 2984.
[291] See 9 Tr 2984-2985.

> If the Company's commitment to spend on these programs is so highly dependent on weather events, then it is not a commitment at all.[292]

He recommended that the spending projected for this category be reduced by 20% for 2019 through the end of the projected year, a reduction in total spending of $182,341,000 as shown in Exhibit AG-1.6.

In his rebuttal, Mr. Bruzzano objected, asserting that DTE is committed to spending the forecast strategic capital amounts, quoting DTE's discovery response in AGDE-3.72 referenced by Mr. Coppola, including a chart omitted from the quotation below that shows DTE's 2018 strategic capital spending amounts of $171.8 million on infrastructure resilience & hardening, and $69.4 million for infrastructure redesign:

> AGDE-3.72a Question: Refer to page 16, lines 10-12, of Mr. Bruzzano's direct testimony. Please explain how the Company can make any progress in achieving infrastructure Resilience, Hardening and Redesign if it pulls capital spending away from these programs when other issues arise whether emergent or otherwise.
>
> Answer: It is the Company's goal to invest in Infrastructure Resilience & Hardening and Infrastructure Redesign as described in my testimony because these investments will benefit customers. The Company has already made significant investments in these categories, as shown in Table 6, page 16 of my direct testimony.
>
> * * *
>
> The Company plans to make the investments forecasted in this case unless unforeseen events, such as the severe weather that led to high levels of emergent replacements in 2018, require resources to be diverted to other priorities. The Company expects to continue making progress in its strategic investments and has already done so.[293]

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[292] See 9 Tr 2985.
[293] See 4 Tr 257-258.

He further asserted that strategic capital cannot be evaluated in isolation from other capital expenditures, testifying that DTE "has an obligation to allocate its resources in the best interest of its customers based on the operational circumstances that are occurring at any given time."[294] He expounded on this testimony:

> Overspending in one category could impact the timing of spending in another, leading to a period in which a specific category may be temporarily underspent vs. the forecast. For example, spending on Infrastructure Resilience and Hardening was below forecast because resources that would have otherwise been utilized on those projects and programs had to be dedicated to Emergent Replacements. For this reason, categories that are overspent and categories that are underspent must be looked at together when determining the level of capital expenditures the Company will incur in the provision of service.[295]

He then testified that 2019 emergent replacement spending exceeded forecast amounts by $114 million, as shown in Schedule V1 of his Exhibit A-31, and testified that DTE cannot defer emergent replacements in favor of strategic capital investments.[296] He stated that if emergent replacement expenditures were below forecast, DTE would be able to accelerate strategic capital programs, and provided his view of the consequences of disallowing 20% of DTE's strategic capital projection:

> The Company would not be able to implement many projects that are aimed at reducing risk, improving reliability and managing costs. As discussed on page 38 of my direct testimony, "There would be several negative consequences:
>
> • The system would continue to degrade and the volume of equipment failures would grow, with negative impacts on safety, reliability, and costs. An acceleration of equipment failures would cause a costly spiraling effect, in which greater and greater levels of capital expenditures are deployed to repairing, as opposed to preventing, failures.

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[294] See 4 Tr 258.
[295] See 4 Tr 258.
[296] See 4 Tr 259.

• It would become extremely challenging to support economic development and customer growth, as overloaded circuits would not be addressed (further damaging equipment) and needed capacity would not be added, making it uneconomical and unacceptably slow for new customers to connect to the grid.

• The system would be less resilient to intense weather events, putting the service territory at greater risk of prolonged outages.

• The system would not have the infrastructure or the technology to support further penetration of DER and EV."[297]

This PFD finds that Mr. Coppola has articulated a legitimate concern regarding the likelihood DTE will spend the projected capital amounts for this category. Mr. Villareal also noted that these funds may not be used for the programs identified.[298] In several rate cases over the past 5 years, DTE has reported underspending in this category. Contrary to DTE's assertions, the Commission has not treated projected capital expenditures as an overall budget, but has specified that DTE needs to show the specific spending reviewed in a rate case is not only reasonable and prudent, but also will occur. When DTE foregoes capital expenses that it has told the Commission are "necessary" because weather events require additional resources, DTE is essentially shifting weather-related risks to the ratepayers.[299] While other unforeseen events, such as permitting delays, can prevent DTE from meetings its strategic capital resource commitments, the utility should not expect to operate its system even in the face of extreme weather with a

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[297] See 4 Tr 260-261.
[298] See 9 Tr 2702.
[299] DTE may benefit from weather. For example, its actual 2018 adjusted net operating income was approximately $100 million more than its weather-normalized adjusted net operating income. See Exhibit A-3, Schedule C-1, line 21.

capital expense budget set on the basis of normalized weather, sacrificing other important spending priorities, but should raise the necessary capital.

Mr. Coppola's testimony is persuasive that at least for 2019, DTE will be unable to achieve the spending "goal" it set for itself, and that a 20% reduction in projected expenses is warranted. For 2020 and the last four months of the projected test year, this PFD recommends that in lieu of a further spending disallowance, the Commission provide more active oversight of DTE's efforts to meet its spending commitments in this area. This recommendation is also based on Mr. Bruzzano's discovery response, quoted more fully above, asserting: "[T]he Company plans to execute its full slate of strategic investments, even if unforeseen factors in any given year (such as large storms) cause these investments to be delayed."

Staff also recommended two relatively minor adjustments to the AMI-related projections in the tech and automation line of DTE's strategic capital spending. Those are discussed separately below. Because this PFD finds Staff's adjustments are warranted, this PFD recommends excluding those lines from the 20% adjustment to 2019 expenditures recommended above. Thus, this PFD recommends that the Commission reduce DTE's projected 2019 capital spending for strategic capital by $70.4 million, in addition to the adjustments recommended below. This represents 20% of the totals for 2019 on pages 7 and 8 of Schedule B5.4, and 20% of the totals excluding AMI (lines 609) of Schedule B5.4, page 9.

v. AMI-Related Tech and Automation

As shown in Schedule B5.4, page 9, DTE's technology and automation line item includes 4 project lines related to AMI. Ms. Robinson sponsored these AMI-related capital expenditures, which she referred to as “AMI technology enhancements.” She discussed DTE’s AMI 3G to 4G communications upgrade program, testifying that the cellular industry is phasing out 3G cellular service in Michigan by late 2020, and that DTE would need to replace 3,000 cellular relays and 6,000 cellular industrial customer meters with 4G devices: “Without this upgrade, DTE Electric would lose daily communication with approximately 1 million of the 2.6 million DTE Electric residential electric meters and communication to approximately 6,000 industrial meters.”[300]

Ms. Robinson testified that in addition, DTE plans to add 300 additional relays to strengthen its communications network as a “second optimization wave.”[301] She stated that the residential project will cost $30.3 million, with $22 million of that amount to go to the supplying vendor, and the remainder “for analysis, project management, DTE labor, digital cards, and other necessary equipment.”[302] She testified that $2 million was allocated to the optimization phase to install the 300 additional relays.[303] Regarding the cell relay enhancement, she testified:

> The new devices are sited to be installed on poles within the targeted geography and not on the customer premise. This design enhancement reduces the need to be on the customer premise for telecommunication network issues. Also, cellular 4G technology has significantly better Radio Frequency (RF) signal propagation than 3G cellular. These features will provide better connectivity to meters enabling the Company to improve on its current AMI read rate and help to eliminate hard to reach customer meters within the AMI network.[304]

[300] See 9 Tr 2620.
[301] See 9 Tr 2620.
[302] See 9 Tr 2621.
[303] See 9 Tr 2621.
[304] See 9 Tr 2623.

Ms. Robinson testified that the industrial project will cost $12.4 million, with the majority of the funding to replace the 6000 3G devices, with 950 of those to be "advanced power quality meters" for the largest industrial customers.

Staff takes issue with two additional elements of the 3G to 4G upgrade.

a. 3G to 4G (advanced power quality meters)

Dr. Wang recommended that the Commission reject DTE's planned expenditures to install 950 power quality meters for its largest industrial customers with loads of 1MW or more. Citing Exhibit S-12.3, she testified that DTE did not attempt to quantify the benefits of its proposed expenditure and did not present evidence of specific power quality issues. She testified that the 3G to 4G communications upgrade can be made without the installation of these meters.[305] While she recommended a $4.45 million capital expense reduction for this program, in its brief, Staff revised its recommended capital expense reduction from $4.5 million to $3.8 million:

In her rebuttal testimony, Ms. Robinson provided additional testimony addressing DTE's rationale for the meter upgrades, indicating that it wants to install the meters not to aid in a root cause analysis after an issue arises but to aid in protecting "circuit or customer equipment":

> The notion that Power Quality (PQ) meters are only a prudent investment based on definitive evidence that selected installation sites are presently, or have historically, experienced power quality issues is centered in using PQ meters as a forensics tool to aid in root cause analysis after a disturbance has been noticed, presuming that the conditions causing the disturbance persist. It is the Company's position that the investment in PQ meters for our top load customers is in fact a prudent investment to reduce impact and/or damage to circuit or customer equipment when disturbances occur.

[305] See 9 Tr 3364-3366.

> Due to the 1MW load scale these sites represent, it is crucial that disturbances are immediately detected and relevant data is available to inform Company and/or Customer personnel to initiate the most appropriate responses. As such, the PQ meters must generally be in service prior to occurrences of electrical disturbances. Further, it is the appropriate time to make this investment as the existing 3G meters must be replaced due to planned obsolescence of the service.[306]

Ms. Robinson testified also that upgrading the existing industrial customer meters with non-power quality 4G meters would cost $1,358,500.[307] Based on this rebuttal, Staff calculated a revised meter replacement cost and adjusted DTE's overall meter funding request accordingly, as explained in Staff's brief.[308] These calculations led to Staff's revised recommended disallowance for this line item of $3.82 million.

DTE relies on Ms. Robinson's testimony in arguing for the additional funding. It adds in its reply brief that Staff "doesn't offer anything but continuing doubt" in response to Ms. Robinson's testimony.[309] DTE notes but does not address Staff's revised brief calculations.

This PFD finds that Staff's adjustment should be adopted. DTE had ample opportunity to explain the need for the advanced power quality meters in response to Staff discovery. In particular, as shown in Exhibit S-12.3, Dr. Wang asked how the meters would reduce unnecessary field visits, improve restoration efficiency, and reduce costs. DTE responded by stating that "these meters enable DTE and our customers to more quickly determine the source of power disturbances and assess the impact of them on the customer's operations." After summarizing features of the meters, DTE further stated:

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[306] See 9 Tr 2633.
[307] See 9 Tr 2634.
[308] See Staff brief, pages 36-37.
[309] See DTE reply at 43.

"The power quality data reduces field visits, ensures the right field people are dispatched and improves restoration efficiency by providing relevant historical data that is remotely accessible and more indicative of problem sources, thereby reducing the labor time and shortening the resolution cycle, promoting customer satisfaction as well." If Staff did develop the idea that DTE's proposal was primarily designed to aid in root cause analysis, it was DTE's analysis that supported that view. In addition, DTE could have presented a benefit-cost analysis in support of its proposal, and chose not to do so.

b. cell towers and relays (mesh network)

Dr. Wang recommended a reduction to DTE's proposed spending, noting that the Commission rejected DTE's projected capital spending to install 300 relays in Case No. U-20162. Citing Exhibits S-12.1 and S-12.2, she testified that Staff continues to find strengthening network communications to improve the current read rate of 99% is unnecessary, and well above the required 85%.[310]

Ms. Robinson testified in rebuttal that DTE's main purpose in strengthening the communications network is not to improve read rates but to sustain them. She testified that seasonal vegetation interferes with communications "primarily due to leaves blocking the radio signals."[311]

In its brief, Staff emphasizes that it made its recommendation based on DTE's discovery responses:

> In her original testimony, discovery question response, and cross-examination, Company witness Robinson confirmed that the 300 additional relays are intended to strengthen the communication network (9 TR 2620;

[310] See 9 Tr 3363-3364.
[311] See 9 Tr 2632.

> Exhibit S-12.1’ 9 TR 2637). She did not mention a “sustainment” of AMI read rates in either testimony or subsequent discovery responses regarding the purpose of the 300 additional relays. Information regarding the project motivations, metrics for success, benefits, and costs should be provided with the initial Company testimony and exhibits. This allows Staff and intervenors adequate opportunity to examine the information and ask discovery questions with respect to why they are necessary simply to maintain the status quo.[312]

Staff further argues that DTE did not establish that the $2 million expenditure to deal with pockets of meters affected by vegetation is cost-effective, noting that DTE did not present any alternatives that it considered, including its tree-trimming program. The RCG supports Staff’s recommended disallowances.[313]

In its reply brief, at pages 40-43, DTE relies on Ms. Robinson’s testimony, and characterizes as “speculative and unsupported” Staff’s suggestion that tree trimming could address reception issues caused by leaves blocking radio signals:

> There is no evidence in the record (and none exists to the Company’s knowledge) to support the notion that the Company’s right to trim trees in easements or other rights of way along its power lines would have any discernible positive effect on the reception of AMI meters attached to customer buildings.[314]

DTE also disputes Staff’s reliance on the Commission’s service quality standards:

> Staff’s Initial Brief, pp 33-34, further suggests that “this rate case is not the proper venue to argue for a change” to the 85% read rate standard, and notes that “Staff is currently undergoing stakeholder processes to review and update the Service Quality and Reliability Standards for Electric Distribution Systems in Case No. U-20629.” Although the Company does agree that the standards should be updated, it was not suggesting a change to the read rate standard in this rate case, but rather maintains that it is inappropriate to base a decision on a standard that (apparently without dispute) needs to be updated.[315]

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[312] See Staff brief, page 32.
[313] . See RCG brief, pages 34-35.
[314] See DTE reply, pages 41-42.
[315] See DTE reply, page 42.

This PFD finds that Staff's recommendation should be adopted. The Commission rejected DTE's similar capital expense projection in Case No. U-20162. A review of Exhibit S-12.1 shows that when asked to detail the current strength of the communication network and the strength with the additional relays proposed, DTE responded: "Using a metric of meter response within the prior 3-Day period, the current strength of the communication network can be stated as 99%, or missing contacts with ~26,000 meters. The expectation for the optimized communication network is at least 99.5% or missing contacts with less than ~13,000 meters at any point in time." As Staff argues, this is a planned improvement. DTE's response made no exception to its stated 99% attainment for "seasonal vegetation."

d. Customer Advances for Construction (CIAC)

Mr. Jester noted the magnitude of projected spending for connections and new load, testifying that the projected amounts are 29% of DTE's projected base capital program spending. Reviewing the projected CIAC amounts in line 15 of Schedule B5.4, page 2, he testified that these amounts are approximately 23% of the connections and new load spending. Mr. Jester recommended that the Commission revise the required new customer contribution toward construction costs.

> Net capital additions in 2018 through the projected test year due to Connections and New Load capital expenditures, partially offset by Customer Advances, are therefore $360.76 million. This amount constitutes about 4.4% of the projected distribution rate base in this case and are therefore material to the determination of electricity distribution rates.[316]

[316] See 9 Tr 3815.

He presented evidence showing that DTE is not experiencing net load growth,[317] and testified that these additions to rate base are driving electric distribution rate increases. He acknowledged that the current CIAC policy is longstanding, but further noted that the current policy predates unbundled ratemaking. He expressed a concern that the current policy leads to cross-subsidization:

> Current CIAC policy, as presented in DTE Electric's tariff section C6, provides that DTE Electric's contribution to line extensions and service connections is 2 times the estimated annual revenue for residential customers and commercial customers under 1,000 kW annual demand. For those customers with estimated annual demand over 1,000 kW, the customer may choose the standard allowance of 2 times estimated annual revenue or a schedule of costs per kW annual demand that varies between full-service and distribution-only customers and between rate schedules in a way that appears to reflect total demand charges for production and distribution. However, since these Company contributions are for additions to distribution plant, Company contributions based on total revenue are likely to cause subsidies by those rate classes with a high ratio of distribution revenue to total revenue (i.e., residential and secondary commercial customers) to those rate classes with a low ratio of distribution revenue to total revenue.[318]

After looking at percentage of distribution capital costs to total distribution system costs paid by each customer class, and looking at the percentage of distribution capital costs to total revenue paid by each customer class, Mr. Jester discussed the concept of payback periods to recoup the line extension or other construction costs:

> The capital portion of distribution required revenue is the revenue from a customer that is computed as needed to cover the costs of this investment. Doing so equitably across rate schedules would produce the same payback period across all rate schedules. As can be seen in Exhibit MEC-62 (DJ-5), the payback times under the current policy vary from as low as 2.7 years for municipal street lighting to as high as 34.7 for R10 Interruptible Supply customers.

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[317] See 9 Tr 3815-3816
[318] See 9 Tr 3816.

> The correct payback period to use for all rate schedules is the inverse of the economic carrying cost of distribution capital investments. Economic carrying cost is the life-cycle average revenue requirement for a given investment, divided by the average undepreciated balance of that investment. We can closely approximate this by dividing the Total Electric Distribution Rate Base in Exhibit A-16 Schedule F1.2, which is $8,197.321 million by the Capital Rev Req for Total Electric that I compute above, which is $1,254.415 million. That ratio is 6.58 years, which is significantly less than the 8.2 years average payback time based on expected annual distribution revenue that is the current average payback time under DTE Electric's current practices.[319]

Based on his further analysis, Mr. Jester concluded that a consistent payback period for distribution revenue would be 4.5 years, and correspondingly recommended that the Commission change the CIAC policy to limit DTE's contribution to 4.5 times the estimated annual distribution revenue from the customer.[320] He testified that this would reduce DTE's projected capital expenditures by approximately 20%, with the additional caveat that "[i]f the connections and new load investments are more focused on non-residential customers than the average allocation of distribution rate base," the reduction could be even greater.[321]

DTE objected to the proposed change. Mr. Bloch presented rebuttal testimony contending that the change in CIAC policy would create a disincentive for new customers to locate in DTE's territory "at a time when DTE Electric's growth rate is low as noted by Witness Jester," does not properly recognize the incremental contribution to fixed costs provided by new customer load, and "moves away from a long-standing policy and value proposition that existing customers have received and that new customers will not

[319] See 9 Tr 3819-3820.
[320] See 9 Tr 3820.
[321] See 9 Tr 3821.

receive." [322] Mr. Bloch cited the Commission's October 31, 2012 order in Case No. U-17055, in which the Commission approved the "standard allowance table" for customers over 1 MW, to show that the Commission had considered both production and distribution related contributions provided by new load even after the initiation of what both the MEC Coalition and DTE refer to as rate unbundling.[323] Mr. Bloch testified that the standard offer table was created "to provide transparency regarding the allowance provided to commercial and industrial customers with demand of 1,000 kW and larger," and "to provide consistency with other large utilities in the State."[324] Mr. Bloch disputed that there is any concern for subsidization in the current policy, asserting that the greater use by residential and secondary commercial customers of the distribution system is a sufficient explanation for the cost allocation and "says nothing whatsoever regarding the possibility for interclass subsidies."[325] In its brief, DTE relies heavily on Mr. Bloch's testimony.[326]

In its brief, the MEC Coalition argues that DTE ratepayers incur substantial distribution capital expenditure to connect new customers and new load. The MEC Coalition cites Schedule B5.4, page 1, which shows among other things that DTE's projected bridge and test year capital costs for the connections and new load line item at approximately 30% of its base program capital costs, and approximately 25% after the contributions are subtracted. MEC argues that distribution capital expenditures for new customers outpace load growth and are driving distribution rate increases by increasing

[322] See 8 Tr 2293.
[323] See 8 Tr 2293-2294.
[324] See 8 Tr 2294.
[325] See 8 Tr 2295.
[326] See DTE brief, pages 55-56; DTE reply, pages 37-38.

distribution rate base approximately 4.4% per year, while customer growth is increasing only approximately 2%.[327] The MEC Coalition disputes Mr. Bloch's testimony that there is no evidence of subsidization. The MEC Coalition reviewed Mr. Jester's testimony, arguing that Mr. Jester demonstrated that residential and secondary commercial customers are likely subsidizing new primary customer construction, because he showed that it takes approximately 2 decades for the capital investment necessary to connect new primary customers to be paid back by those customers, while in the meantime, residential and secondary commercial customers pay a higher proportion of distribution system costs.

The MEC Coalition argues that Mr. Bloch's testimony did not substantiate his claim that because new customers contribute to fixed expenses, they lower rates for other customers:

> DTE presented no evidence that any new customers located in DTE's service area because of its CIAC policy. Nor is there any basis to conclude that adjusting the CIAC policy to derive the ratepayers' contribution based on new distribution rather than new total revenue would dissuade new customers from locating in DTE's service area. Moreover, even if there were evidence showing that the ratepayer contribution to new customer and load costs in fact increases economic development in DTE's service area, the evidence shows that the ratepayer contributions are increasing at a faster rate than the new customer counts – an increase of 4.4% in rate base additions to support Connections and New Growth, compared to about 2% customer count increases over a 3-year period. The theory that the CIAC policy supports new customer growth is thus empirically thin.[328]

The MEC Coalition also reviewed two key Commission orders addressing the CIAC policy, the Commission's October 18, 1976 order in Case No. U-4738, and its

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[327] See MEC brief, page 60.
[328] See MEC brief, pages 65-66.

October 31, 2012 order in Case No. U-17055. It argued that in Case No. U-4738, when the Commission first established the policy that DTE contributions to a new customer connection would be based on 2 times the expected annual revenue for that customer, the policy was intended to limit subsidization of new customers by current customers:

> In that proceeding, DTE proposed a rule amendment to increase customer contributions for new connections to address cash flow or financial problem that DTE had experienced. According to that Commission Order, DTE witness Mayotte in that case acknowledged that "existing customers do to an extent subsidize those customers who request an extension," and that the ratio of total investment to total annual revenue for an average customer in different classes ranged from 2.2 to 3.2 to 1. Staff witness Croy supported modifying DTE's proposal, suggesting a reasonable investment to revenue ratio was 2:1. While this ratio "would still require some subsidization of new customers by existing customers, the new customers would be contributing more towards the new facilities than they are now required." The Commission agreed with Staff's proposal and adopted rules providing DTE's contribution to new connections is based on two years of estimated annual revenue.[329]

The MEC Coalition argued that Mr. Bloch's testimony essentially attempts to defend the CIAC policy as an economic development tool, noting his testimony characterizing the policy as a "value proposition that existing customers have received," and his citation of the Commission's order in Case No. U-17055:

> DTE's position further confirms that it views the CIAC policy to be a ratepayer-funded mechanism to incentivize economic development in its service territory. This is consistent with the Commission's most recent action on CIAC policy in 2012, when it approved the alternative contribution allowance for large secondary customers discussed above. In a pair of twin *ex parte* proceedings filed by DTE Electric and Consumers Energy, the Commission allowed an amendment to each utility's rate book to offer the optional standard allowance for new or expanding large commercial and industrial customers. As recited by Mr. Bloch, Commissioner Quackenbush was quoted in a press release issued the day the twin orders were approved, stating the change "will make Michigan more attractive to

[329] See MEC Coalition brief, page 61.

> businesses" and would "improve Michigan's economic development climate."
>
> The 2012 *ex parte* proceedings did not, however, consider the impact of the standard CIAC policy, nor the optional table approach, on other rate classes. Those were *ex parte* proceedings that lacked any of the fact-finding rigor of an adversarial process. There is no evidence the Commission in those proceedings considered the potential impact on rates -- instead, it concluded there would be no change in rates or cost of service to any customer because the tariff was optional. It is apparent that there was no analysis or record related to the issues raised herein -- i.e., the impact of the subsidy on ratepayers generally, nor equity between different rate classes.[330]

Additionally, the MEC Coalition disputes any lack of transparency in its proposal.

This PFD finds that Mr. Jester's recommendation appears generally reasonable, and appropriately tailored to limit ratepayers' exposure to substantial recurring distribution system cost increases in excess of any demonstrated benefit. As the MEC Coalition argues, there is nothing inherently lacking in transparency about a policy based on 4.5 times distribution revenue rather than 2 times total revenue. Nonetheless, in view of the longstanding nature of the CIAC policy, and the value of transparency on this issue, this PFD recommends that the Commission delay the implementation of the revised proposal by one year, to give DTE the opportunity to implement it without unduly confusing people or companies currently pursuing new connections.

It is worth noting in support of the reasonableness of increasing the customer contribution, that Mr. Jester's testimony that DTE's load is not growing significantly and his testimony that the significant increase in customer connection costs are driving rate increases is unrebutted on this record. In addition, as discussed below, the demand for

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[330] See MEC Coalition brief, pages 66-67.

relocations and new connections is distracting DTE from necessary strategic capital investments[331] that are degrading the quality of service experienced by other customers, while their rates are increasing to accommodate these construction activities. Given that existing customers are both burdened by higher rates and poorer-quality service as a result of DTE's recent high volume of new construction, it appears the time has come for the Commission to revise the CIAC policy.

e. Performance-Based Ratemaking Mechanisms

As the discussion above shows, DTE has not yet found an approach to strategic capital spending that enables it to demonstrate a firm commitment to the programs it acknowledges are necessary in order to significantly improve its distribution system performance. Among the most telling illustrations is Mr. Bruzzano's testimony that in a year when emergent replacements are below normal, then DTE will be able to make additional investments in strategic capital:

> Should Base Capital expenditures during the forecast period run below the projection, the Company would accelerate the strategic investments that provide the greatest customer benefits.[332]

Hoping for below average storm activity to get caught up is not a confidence-inspiring plan. In recent rate cases the Commission has provided numerous "carrots" to facilitate this. The Commission and the ratepayers, through projected rate base, have provided a substantial level of prefunding for specific capital expenditures. In addition, the Commission has been instrumental in causing DTE to formulate a five-year plan for

[331] See, e.g. Bruzzano, 4 Tr 132.
[332] See 4 Tr 158.

distribution spending; and has provided high-end authorized returns on equity in part to recognize the capital investments DTE needs to make to its system. None of these beneficial approaches are working, because DTE's distribution system performance remains in the 4th quartile and DTE's strategic capital spending for 2019 is once again expected to be below projected levels.

As Mr. Bieber and Mr. Jester suggest, performance-based ratemaking measures should be considered. While Mr. Bieber's recommendation would be easy to implement, it is not clear that a 10-basis-point reduction in the authorized rate of return, to be credited to ratepayers over what would likely be a period of years until its distribution system performance reaches an average level, provides any meaningful incentive to DTE sufficient to overcome the profit motivation and other factors that cause the utility to divert resources from needed system maintenance and upgrades to storms and new business. Mr. Jester's proposal is that the Commission work to develop targeted performance metrics and measures. This PFD recommends that the Commission adopt MEC's recommendation, but nonetheless, it will clearly take significant time to implement, either in DTE's next rate case or the rate case after that.

Therefore, given the lack of immediate measures to ensure that strategic capital given the time involved, this PFD recommends that the Commission also consider using the oversight authority provided by MCL 460.56 to require DTE's management to explain its plans to both meet emergent capital needs and meet its system maintenance obligations.

f. System Hardening and Conversion

As noted above, Soulardarity expressed concerns with DTE's proposed system hardening and conversion plans. In its brief, Soulardarity acknowledged the Commission's decision in Case No. U-20162 approving DTE's proposed plan to convert certain areas of its 4.8kV system to 13.2kV, and to harden other areas to ensure safer, more reliable conditions until the full conversion can take place. Soulardarity explains its concerns with the safety and reliability of the 4.8kV system, its concern that low-income communities are the least able to accommodate service disruptions without hardship, and that DTE's decision-making on which systems to convert and which to harden are not transparent, but overly favor reducing its future maintenance costs. Soulardarity asks for multiple forms of relief:

> 1) The Commission should not approve DTE's proposed residential rate increase to fund hardening and conversion.
>
> 2) In the event that the Commission determines that a rate increase is necessary to fund the new and improved infrastructure, it should direct DTE to reconsider which rates would need to be increased, considering a reduction in residential costs and shifting the infrastructure cost burden to other rate classes.
>
> 3) The Commission should require that DTE provide public transparency on the basis for its decisions regarding which systems to improve (including hardening and conversion) and maintain.
>
> 4) The Commission should direct DTE to employ a cost measurement mechanism by substation that takes into account the value of the product it delivers to those ratepayers, reflecting the cost and benefit of safety and reliability upgrades.
>
> 5) The Commission should require as a policy and direct DTE to consider a service gap between low-income and higher-income ratepayers in plans for upgrades to the distribution and transmission systems, because Michigan law requires utilities to provide equitable service at equitable rates.

> 6) The Commission should require as a policy and direct DTE to use tools such as the EJScreen67 that would inform the Commission, DTE and other utilities, and the public when energy service must be analyzed in the context of other environmental and social indicators.

DTE responded in its reply brief, contending that Soulardarity is mischaracterizing its program:

> In contrast, the record reflects that DTE Electric is prioritizing the order in which it addresses the different sections of the 4.8 kV system based on numerous criteria, including safety and reliability performance, with safety being the primary driver in the prioritization efforts (4T 165-66). Soulardarity's Initial Brief, p 10, acknowledges that "Soulardarity reiterates its position in U-20162," but Soulardarity fails to address the substantial costs and other problems with its position. The Commission previously agreed with the ALJ, who "agreed with DTE Electric that the 4.8 kV hardening proposal is economically efficient and that a more complete conversion of the system to 13.2 kV would be expensive and provide limited incremental benefit" (May 2, 2019 Order in Case No. U-20162, pp 31, 33). Moreover, the 4.8 kV hardening will deliver safety and reliability improvements faster than 13.2 kV conversion could (4T 284), and circuits are prioritized based on the greatest risk of something happening that could cause an injury (4T 365).
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> Soulardarity's Initial Brief, pp 11-14, further suggests that the Company should make "safety and reliability investments" based on "ratepayer economics and environmental justice." The Company disagrees and emphasizes that it appropriately makes its decisions about safety and reliability investments based on the needs and characteristics of its system. In addition to the discussion in DTE Electric' Initial Brief and above, Mr. Bruzzano explained that the Company's prioritization framework provides the greatest weighting to safety improvements (4T 283; Exhibit A-23, Schedule M7). Also, while approximately 14% of the Company's customers are located in the City of Detroit, the Company is investing more than 25% of its 2019 Strategic Capital in the City of Detroit to address aging infrastructure and improve safety and reliability, and these significant investments will continue in future years (4T 283-84). Soulardarity's suggestion for "shifting the infrastructure cost burden to other rate classes" (Soulardarity Initial Brief, p 14) is illegal (see section III above).[333]

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[333] See DTE reply, pages 33-34.

Since the Commission addressed Soulardarity's concerns in substantial part in Case No. U-20162, and approved DTE's proposed hardening, there is no basis on this record to reconsider that decision. In its order, the Commission expressly found that DTE was considering both safety and economics in implementing that program.

As the discussion above shows, this PFD recommends a reduction in the funding for DTE's proposed hardening and conversion activities, but not the complete elimination of that funding. Again, the Commission approved DTE's proposed plan in Case No. U-20162. Nonetheless, as also recommended above, this PFD recommends that the Commission consider employing performance-based ratemaking and other measures such that the utility will actually undertake system improvements for which it has received ratepayer funding. Without diminishing Soulardarity's concerns for residents of communities whose 4.8kV infrastructure is not scheduled for hardening or conversion, the foregoing discussion also shows that even with prefunding by ratepayers for the conversion and hardening DTE has planned to undertake, it is an important and challenging undertaking for the Commission to hold DTE to its existing commitments.

As for Soulardarity's requests for greater transparency in DTE's decision-making, this PFD acknowledges that Soulardarity sought relevant information from DTE's distribution system witness in this case through discovery and during cross-examination, and finds that future rate cases would benefit from a greater upfront explanation by DTE of the factors and scoring process that goes into prioritizing the circuits to be hardened. DTE should also plan to address its prioritization in its next distribution system plan filing.

As for Soulardarity's other requests, within the context of this rate case, it is not possible to mandate that DTE use any particular screening tool, or to conclude that if DTE were to implement such a tool, it would reach a different conclusion regarding any of the circuits at issue. Nor is it possible to set rates that ignore cost of service principles by shifting distribution costs to other classes without a technical basis to do so.

g. NWA

While the ELPC Group does not seek any specific expense adjustments, it does make two arguments that should be considered in connection with DTE's proposed distribution system spending plan.

First, the ELPC Group argues that DTE's projected distribution system spending plan does not meet the requirements of the Commission's order in Case No. U-20147, and that its proposed spending in this case does not adequately incorporate NWA.[334]

In its brief, DTE articulated its view of and plans for NWA pilots at this point in time:

> The electric generation and distribution industry is evolving, as technologies such as energy storage have seen cost declines and could become economic alternatives to traditional distribution investments, particularly when integrated with new demand response (DR) and energy waste reduction (EWR) alternatives. At least for the current time, however, the Company has determined that Non-Wires Alternatives (NWA) are best suited to addressing situations in which circuits or substation equipment is or might become overloaded, or to help delay or offset planned traditional upgrades (4T 206). Mr. Bruzzano described the Company's methodology for developing NWA pilots (4T 206-208), and the Hancock NWA Pilot and the Substation #2 NWA Pilot that the Company is pursuing as part of the EWR, Non-Wire Alternative settlement U-18268, Attachment E (4T 208-209). The Company is also pursuing the O'Shea Park Energy Storage Pilot (which couples battery storage with existing solar generation), and the Mobile Battery Storage Trailer Pilot (which involves a mobile battery system that could be used to provide load support). (4T 209-10).[335]

[334] See ELPC brief, pages 16-18.
[335] See DTE brief, page 55.

This PDF finds that the ELPC Group's concern with DTE's exploration of NWA is best addressed through the five-year distribution system planning process.

h. Interoperability

Second, the ELPC Group cites Mr. Villareal's testimony in arguing that DTE is not adequately considering interoperability testing:

> Mr. Villarreal highlights DTE's failure to adequately address interoperability in its Plan. Interoperability, as defined by the National Institute of Standards and Technology, refers to the capability of two or more networks, systems, devices, applications or components to work together, and to exchange and readily use information—securely, effectively, and with little or no inconvenience to the user. 9 Tr. 2706 (Villarreal Direct). As DTE modernizes its distribution system, in particular through the addition of sensing, monitoring, communications and automation technologies, ensuring the interoperability of those technologies is critical. Without ensuring interoperability, DTE may need to implement expensive integration layers between its different products or develop a proprietary solution, either of which would increase costs for customers. 9 Tr. 2707 (Villarreal Direct).[336]

DTE responded in its reply brief, acknowledging that it needs to follow the National Institute of Standards definition of interoperability, but disagreeing that third-party testing is necessary:

> DTE Electric and vendor testing confirms compliance, conformance, and integration of all systems. Third-party testing of the same system is unnecessary and would not provide additional value. All of Mr. Villareal's indicated concerns are either unfounded or already being addressed by the Company (4T 278-81, 313-14).
>
> ELPC's Initial Brief, pp 19-20, responds by suggesting that the Company's testing protocol is inadequate because it does not guarantee the future. But the future is inherently uncertain. As Mr. Bruzzano testified, it is "not clear what future systems might be necessary or what the interoperability requirements of a new system would be" (4 T 315).

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[336] See ELPC brief, page 18.

Mr. Villareal's testimony on this topic is summarized in section b above. This PFD finds that Mr. Villareal is especially knowledgeable in the area of interoperability testing and the experience of other utilities. DTE is proposing to spend hundreds of millions of dollars on systems that need to work together. While this PFD does not find any basis to mandate that DTE pursue third-party testing, the Commission should remind DTE that it puts its shareholders at risk of a future disallowance if it seeks to prematurely replace or retire systems or purchase expensive retrofits to address interoperability concerns that could have been avoided had it been open to the reasonable suggestions of an expert in the field.

5. Demand-Side Management/Demand Response (Schedule B5.6)

Mr. Cejas Goyanes presented testimony in support of DTE's projected capital expenditures of $16.6 million for the bridge period and $8.5 million for the projected test year as shown in Schedule B5.6 of Exhibit A-12. ABATE and Staff took issue with elements of the company's proposed capital expenditures.

a. ABATE Concerns

ABATE expressed a concern that DTE's proposed spending was not consistent with what was presented in its recent IRP filing.[337] Staff took issue with the company's request for funding for pilots that have not yet been fully developed.[338] DTE argues that its demand response (DR) programs comply with the three-phase approach provided by

[337] See ABATE brief, pages 13-16.
[338] See Staff brief, pages 10-12.

the Commission in Case No. U-18369. To address Staff's concern regarding the pilot programs, it offered to meet with Staff as it develops the programs.[339]

In its September 15, 2017 order in Case No. U-18369, the Commission laid out a process for evaluating DR programs and reconciling DR expenses:

> The three-phase approach is a multi-step process where DR proposals, including program costs and benefits, are evaluated in the IRP. Once DR plans are approved as part of the IRP, the DR programs costs are considered approved and are included in rates in a utility's next general rate case. In between IRP proceedings, a provider may propose changes to DR programs or pilots, and these changes will be evaluated and approved in rate cases and must be included in the next IRP. The third phase involves a reconciliation of the DR program costs and customer participation rates (i.e., demand savings achieved) that will occur annually in a manner similar to that used in the provider's EWR reconciliation, with rates and participation reconciled against the levels approved in the IRP.[340]

Here, DTE filed its IRP in Case No. U-20471 on March 29, 2019, approximately three months before its July 8, 2019 filing in this case.

Ms. Alderson identified three differences between DTE's projected DR costs in this case and the costs included in its IRP: $2 million in additional pilot program costs; $3 million for the Insight program not included in the IRP; and no additional revenue for the Programmable Controlled Thermostat (PCT) program in this case although $3 million was included in the IRP.[341] She expressed general concerns that the Commission could unknowingly approve different program costs in each order "in quick succession," and that DTE was not adhering to the Commission's three-phase approach. Focusing on the Insight program, she objected that DTE claims to have excluded the program from the

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[339] See DTE brief, pages 66-72.
[340] See September 15, 2017 order, page 5.
[341] See 7 Tr 1815-1816.

IRP because it does not measure the program as a supply resource, even though in the IRP proceeding DTE claimed that the program is intended to reduce peak demand.[342] She recommended that DTE either adjust its requested capital expense projections or provide evidence showing that its current proposals are just and reasonable in the context of its IRP. She specifically recommended that projected funding for the Insight program be rejected.[343] Finally, Ms. Alderson expressed a concern that DTE's proposed inclusion of DR capital costs in rate base in this case is inconsistent with its request for a Financial Incentive Mechanism (FIM) in case No. U-20521.[344] In Exhibit AB-6, she presented calculations showing the revenue requirement impact of eliminating funding for the Insight program and the return on all DR program capital costs.

In his rebuttal testimony, Mr. Cejas Goyanes provided his opinion that the company's projected capital expenditures are reasonable and prudent. He noted that at the time of its filing, DTE did not have an approved IRP, and his direct testimony addressing the differences between DTE's IRP filing and its request in this case.[345] Addressing the Insight program specifically, he testified that DTE has been investing in the program since 2014, has recently enhanced the program, and further, that the program is not appropriately considered in an IRP because DTE does not expect to have the program qualified as a load modifying resource registered with MISO.[346]

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[342] See 7 Tr 1816-1817.
[343] See 7 Tr 1818.
[344] See 7 Tr 1818-1819.
[345] See 9 Tr 1543-3545.
[346] See 9 Tr 3546-3548.

In its brief, ABATE maintains that DTE's DR funding proposal in this case is misplaced, and emphasizes the benefits of reviewing DTE's DR programs as part of its IRP proceeding.[347] DTE relies on Mr. Cejas Goyanes's testimony in its brief.[348] Regarding the Insight program, DTE argues that program participants saved 30,821 MCF of natural gas, 9,544 MWh of electricity, and 2.74 MW of coincident peak demand.[349]

In its reply brief, DTE further responded to ABATE's concerns regarding the potential for double recovery if a financial incentive mechanism is also permitted, arguing that no party in Case No. U-20521 has proposed consideration of a financial incentive mechanism.[350]

This PFD finds that no specific adjustments are warranted as a result of ABATE's concerns, since DTE's proposals appear consistent with the three-phase framework established by the Commission.

b. Staff Concerns

In his direct testimony, Mr. Cejas Goyannes testified to examples of "other programs," including one called Bring Your Own Device (BYOD) for customers who already have internet-ready smart thermostats, and other ongoing pilot programs started in 2018 or early 2019.[351] Then, he testified:

> Last, the Company is currently exploring additional pilots that could include a peak time rebate program for residential customers and Commercial and Industrial (C&I) battery energy storage pilots. The requested funding will be

[347] See ABATE brief, pages 15-16.
[348] See DTE brief, pages 69-70.
[349] See DTE brief, page 68.
[350] See DTE reply, page 45.
[351] See 9 Tr 3527-3531.

> spent on the exploration and design stages of alternative pilot concepts during 2019 with a goal of launching additional pilots in 2020 and beyond.[352]

After describing the company's current exploration of battery storage pilots,[353] he testified that DTE "seeks to remain flexible enough to efficiently redeploy DR pilot spending and resources as capacity needs change, customer behaviors, and program acceptance are assessed, or other more cost-effective technologies arise."[354] Mr. Cejas Goyannes included all projected spending for "other programs" collectively on line 3 of his Schedule B5.6, with bridge and test year projected expenses of $3.7 million and $4.1 million respectively, and no further cost detail.

Mr. Isakson testified that the Commission should not provide funding for undefined DR pilots, also noting he provided the same testimony in DTE's recent IRP case, Case No. U-20471.[355] He testified that Staff does not object to the BYOD or EPRI pilots.[356]

In his rebuttal testimony, Mr. Cejas Goyannes objected to Mr. Isakson's recommendation. He asserted that removing funding for the undefined pilots "may prevent the Company from conducting the necessary preliminary analyses before full implementation and project plans are developed,"[357] and further asserted:

> Overall, having a capital budget for pilots allows the Company to remain at the forefront of new demand response technologies and allows the Company to quickly switch directions if a pilot is not demonstrating the expected results or investigate whether new and upcoming technologies provide any additional benefit without setting specific program goals.[358]

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[352] See 9 Tr 3531.
[353] See 9 Tr 3531-3532.
[354] See 9 Tr 3532.
[355] See 9 Tr 3136-3137.
[356] See 9 Tr 3136-3137.
[357] See 9 Tr 3550.
[358] See 9 Tr 3550-3551.

He also provided additional descriptions of pilots "under consideration."[359] And he "partially" disputed Mr. Isakson's testimony that the three-phase framework adopted by the Commission gives the company ample opportunity to provide new DR capital spending on other pilots, contending that the framework "may introduce the risk of missed investment opportunities," and that by adopting Staff's disallowance in this case "the development and execution of future DR programs could be delayed by several years."[360] Mr. Cejas Goyannes testified that DTE would be willing to meet with Staff periodically to discuss the company's pilot progress, asserting that if Staff were dissatisfied with company expenditures, it could raise them in the annual reconciliation phase.[361]

In its brief, Staff addressed Mr. Cejas Goyannes's rebuttal testimony, arguing that under the established DR framework, DTE may spend money on pilot programs without their costs entering rates immediately. Staff also acknowledged the company's proposal to meet with Staff to discuss pilot progress, but does not find that sufficient to support including the capital costs for undefined pilot programs in rates.[362] Staff also stated that it is not disclosing the specific dollar amount of its proposed adjustment to Schedule B5.6, line 3, because the cost figures are taken from a confidential exhibit.[363]

DTE relies on Mr. Cejas Goyannes's testimony in its briefs.[364] In its reply brief, DTE expresses its disappointment that Staff does not find DTE's offer to meet with Staff periodically to be sufficient to address Staff's concerns, but states it "remains hopeful in

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[359] See 9 Tr 3551.
[360] See 9 Tr 3552-3553.
[361] See 9 Tr 3553-3554.
[362] See Staff brief, page 11.
[363] See Staff brief, pages 11-12.
[364] See DTE brief, pages 70-72.

attempting to find a practical solution to address Staff's concerns while allowing the Company to move forward with other DR pilots."[365]

This PFD finds that DTE's DR capital expense projections should be adopted with the exception of the "other pilot" program costs to which Staff objected. First, this PFD recommends rejecting ABATE's recommendation, because it does appear that reviewing and approving DR programs in rate cases is appropriate under the Commission's three-phase framework. Second, this PFD agrees with Staff that capital expense projections should not be used a placeholders for vague funding requests. The Commission agreed with Staff's concern regarding this pilot funding in its February 20, 2020 order in Case No. U-20471. DTE's offer to meet with Staff does not overcome the vagueness of its proposal. Also, DTE's contention that a failure to approve the spending in this docket would lead to a "several year" delay in the development and execution of the programs is unpersuasive. DTE does not yet have specific programs; if it indeed takes a year to implement a program once it is designed and approved, the earliest date for implementation would be approximately May of 2021. With DTE's present pace of filings, its next rate case order could be expected to be issued approximately May 2021, and if DTE had presented an approvable pilot program, it could be implemented approximately a year later, of May 2022. That would be a one-year delay, not a several-year delay.

6. Information Technology (IT) Capital (Schedule B5.7)

DTE witness Griffin sponsored testimony in support of DTE's historical and projected IT capital expenditures, summarized in Schedule B5.7 of Exhibit A-12, with

[365] See DTE reply, pages 46-47.

additional detain in Schedules B5.7.1 through B5.7.8 and Exhibit A-24. He testified that DTE's IT capital expenditures were $79 million in 2018, and DTE projects sixteen-month bridge period capital spending of $133 million and test year capital spending of $137 million,[366] which is an increase of approximately 75%. DTE categorizes its expenditures as primarily for "asset health," "value creation" or "non-discretionary" purposes, or a project with a cost less than $250,000.[367] The Attorney General and Staff object to certain of the company's proposed IT projects, with the Attorney General's recommended adjustments totaling $54.9 million and Staff's recommended adjustments totaling $36.5 million.

By way of background, the "Part III" filing requirements adopted in Case No. U-18238 include the following instruction in Attachment 11, item 6:

> Provide spreadsheet/exhibit that includes all of the following information for the highest cost top 25 IT and OT projects in the test year.
>
> a. Project description and functionality of the system with all acronyms defined.
>
> b. Project timelines and spending plans.
>
> c. Project benefits, both in dollars and intangible.
>
> d. Project timeline including expected implementation date.
>
> e. A description of alternatives considered, and rational behind decision.
>
> f. Cost benefit ratio (if applicable).
>
> g. Project business case showing date of Board Approval, and approved project amount for Each Individual Project.

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[366] See 8 Tr 2357.
[367] See 8 Tr 2358-2361.

h. Percentage of total budget that the top 25 projects represents, and total number of projects that fall outside of the top 25.

As shown in Exhibit AG-1.13, DTE provided workpapers for its top 25 IT projects with the information labeled corresponding to this format.

Additionally, in DTE's last rate case, the Commission addressed Staff's request for additional reporting requirements for this category of expense.

> IT programs have not fared well in this rate case. It behooves the utility to provide the level of information that can result in approval of IT capital expenditures. The Commission adopts the additional IT reporting requirements that were agreed upon by DTE Electric and the Staff. These requirements are as follows:
>
> A. Future IT project-level detail will include a breakdown of both the O&M and capital costs. O&M costs will be broken down into two or three sub-categories.
>
> B. For each IT project with a value threshold of $500,000 or more the company will 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 O&M expenditures to date.
> >
> > 4. The total project estimated O&M and capital cost through project implementation.
> >
> > 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 $500,000 (whichever is greater).
> >
> > 7. For IT projects over $500,000, 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.

8. Analysis that shows the company considered cloud computing alternatives in IT project expense requests over $100,000 excluding cyber security or transmission control IT projects.

9. The company will provide 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 with an explanation of why the project was not completed or why it was off budget, only for projects that meet the $500,000 threshold and where additional recovery is being sought in the relevant rate case.[368]

DTE's supporting schedules In Exhibit A-12, Schedules B5.7.1 through B5.7.8, list approximately 140 projects with projected costs exceeding $250,000, with additional lines for projects costing less than that amount. The executive summary pages of the "business case" documents for all projects included in Exhibit A-24 are in Schedules N1.1 through N1.183, with Schedule N1 serving as an index, to comply with the Commission's order.[369] The projects are subdivided in the following categories: Corporate Applications; Customer Service; Plant & Field; Information Technology for IT; Technology and Architecture; Information Protection Security; Infrastructure Operations; and Enterprise Data Analytics. DTE also categorizes capital expenditures and projects by primary purpose: IT Asset Health, Value Creation; Non-discretionary; and projects less than $250,000.

Although the Commission, through the filing requirements noted above and through its May 2, 2019 order noted above, has attempted to assist DTE to provide

[368] See May 2, 2019 order, pages 44-45.
[369] See8 Tr 2362.

meaningful support for its IT cost projections as part of its filing, a review of the documents DTE submitted in this case shows that significant work remains to be done. For the supporting material presented in DTE's workpapers associated with the top 25 IT projects, the record contains 7 examples included in the Attorney General's Exhibit AG-1.13. These workpapers, ostensibly intended to meet the "Part III" filing requirements quoted above, *all* fail to quantify benefits, *all* report that no benefit-cost analysis was conducted, and *all* fail to identify any alternative considered to the project. This comes along with the company's acknowledgement that the top 25 projects represent 75% of the company's projected spending. DTE's own witness, Mr. Griffin, repeatedly asserted that the documents were not an accurate source of information regarding the company's plans.

In addition, the "business case" executive summaries in Schedules N1.1 through N1.183 are difficult to match to projects even with the assistance of the index in Schedule N1. The documents themselves often contain missing information or half-sentences. In the discussion that follows, the projects at issue are discussed in the order they appear on DTE's schedules.

a. Purchase to Pay (Corporate Application Projects, Schedule B5.7.1, line 11)

DTE's Schedule B5.7.1, line 11, projects $1.9 million in capital spending for the bridge period and $3 million for the test year. Mr. Griffin's direct testimony stated that the Commission approved $1.9 million toward this project for 2019 in Case No. U-20162, which is intended to improve DTE's ability to procure and manage inventory and monitor vendor contract performance.[370]

The Attorney General recommended an adjustment of $5.1 million in funding for this project as shown in Exhibit AG-1.14.[371] Mr. Coppola presented the business case document in Exhibit AG-1.13. Mr. Coppola testified that the total cost of the project is expected to be $6.7 million through 2021, and that no cost savings were identified:

> Aside from the typical "buzz words" of enhanced technologies, better integration, greater efficiency, and customer experience, there are no quantifiable benefits presented by the Company to justify undertaking a project of this size. No information has been presented to show that there is a compelling need at this time to transform the P2P process, particularly when there are more pressing needs to upgrade electrical infrastructure that will more directly improve the customer experience through improved customer service and electrical power reliability.
>
> In the project description document included in Exhibit AG-1.13, the Company states that it plans to "sunset" the current SAP system's P2P functionality in 2025 by replacing it with the Ariba system. Given that time horizon, it appears that implementation of this system in 2021 is premature by at least four years.[372]

In his rebuttal testimony, Mr. Griffin testified that the project began in 2018 and the company is midway through the implementation of Ariba to upgrade it P2P system, further asserting:

> P2P is part of an integrated suite of systems that support the Enterprise Resource Planning (ERP) system. The Company will replace the ERP system with a cloud-based version of that platform, known as S/4, in 2025. Our ERP vendor partner is already in the process of transitioning to S/4. By 2025 the version of ERP that the company currently uses will no longer have vendor support.[373]

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[370] See 8 Tr 2368-2369.
[371] See Attorney General brief, pages 76-78.
[372] See 9 Tr 3005.
[373] See 8 Tr 2464.

He characterized the implementation of Ariba as next in a sequence of foundational upgrades.[374] Further, he responded to Mr. Coppola's concern that DTE had not quantified the benefits or cost savings associated with this project as follows:

> While Mr. Coppola would always like to see quantifiable customer benefits or cost savings associated with every investment, not every investment the Company makes has those two elements as its primary drivers. Just like how the Company must, from time to time, replace at-risk sections of the electric infrastructure with newer better materials to ensure safety and operability of the electric system, it must also replace at-risk outdated and unsupported software with newer better software to ensure the security of its platforms and operability of its inventory, procurement and vendor services.[375]

Although denying that associated benefits or cost savings can be quantified, he asserted that the improvements "will all positively affect the timeliness, cost and quality of the services provided to the Customer."[376] Mr. Griffin also testified that DTE is proposing to include only $4.9 million of expenditures in rate base in this case, rather than the $5.1 million total adjustment in Mr. Coppola's Exhibit AG-1.14.

In cross-examination, Mr. Griffin explained the "vendor onboarding" that is part of the P2P system, and answered the Attorney General's question whether DTE performed a benefit-cost analysis by asserting "it's hard to answer that question with a simple yes or no," and further asserting:

> So the current system we have performs those functions, and there's inherent value in the fact that those functions are performed well and that we are able to manage our onboarding of these vendors. As we need to move away from the existing system because it's become obsolete, there's value in continuing to be able to do those functions well, and it would be detrimental both to the Company and to the service we perform to the community to have those services degrade in any way.

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[374] See 8 Tr 2465.
[375] See 8 Tr 2465.
[376] See 8 Tr 2466.

> So the value of this is not necessarily an additive studied value that says this much additional value would be gained, much of this is around an asset health issue that says we have a system that's being sun-setted, in other words, it's going out of support with the vendor and needs to be replaced, and we need to retain the value that the Company already enjoys from this type of a system.[377]

DTE's brief essentially repeats Mr. Griffin's rebuttal testimony,[378] adding a citation to the Commission's December 11, 2015 order in Case No. U-17767 for the following holding: "[i]n the interest of providing customers with safe, reliable, punctual, and quality service, the Commission finds it reasonable to provide DTE Electric with sufficient funds to update its software to prevent it from becoming obsolete."[379] DTE's reply brief repeats the presentation in its initial brief.[380]

In her brief, the Attorney General addressed Mr. Griffin's rebuttal testimony, disputing his contention that the Commission approved spending on this project in Case No. U-20162: "In U-20162, the Commission included that $1.9 million in capital expenditures in the last rate case as no party challenged those expenditures. The Commission did not specifically call out that project in its order in U-20162 and specifically approve the $1.9 million in capital expenditures."[381] The Attorney General disputed that it would be preferable for DTE to spend an additional $4.7 million on a project that it has not economically justified.[382] The Attorney General also cited Mr. Griffin's testimony in cross-examination, contending that when pressed, "Mr. Griffin admitted that he is not

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[377] See 8 Tr 2489-2490.
[378] See DTE brief, pages 76-77.
[379] See DTE brief, page 77.
[380] See DTE reply, pages 47-49, quoting the Commission's December 11, 2015 order in Case No. U-17767, page 78.
[381] See Attorney General brief, page 76.
[382] See Attorney General brief, page 76.

aware of any study conducted to indicate that the system of these items of importance will be of value to customers."[383] The Attorney General also cited Mr. Griffin's testimony on cross-examination acknowledging that it may still diversify its supplier base without this system.[384] Emphasizing the lack of economic analysis, the Attorney General argued:

> The AG points out that while the Company either has not attempted to or cannot show any specific value to customers stemming from the P2P system implementation, the Company has no problem identifying the $6.7 million level of expense it wishes to recover from customers. Under DTE's rationale, if there is no "economic threshold" to be met and no requirement that any kind of benefit be examined or shown, then any project would be acceptable.[385]

Citing Exhibit AG-1.55 to show that DTE has not yet approved a move to the S/4 system, the Attorney General also took issue with that Mr. Griffin's assertion on rebuttal that P2P is part of a larger enterprise system and needs to be put in place as part of DTE's move to cloud computing:

> This is a tactic that DTE often employs, arguing that although the current system may not technically be at "end-of-life" yet, the vendor has already stopped supporting parts of the system, or the Company needs to start transitioning so that it is ready when that system does reach end of life. In this case, that transition is apparently at least a 6-year endeavor, based on the 2025 date provided by DTE. While DTE would undoubtedly like a blank check to continually upgrade its IT systems and always be at the very latest, cutting edge, the relative functionality of systems must be balanced against affordability to customers.[386]

This PFD finds that DTE has failed to justify the reasonableness and prudence of its projected P2P expenditures. Mr. Griffin's description of this project is inconsistent with the documentation DTE provided in its filing. He testified in rebuttal that this project

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[383] See Attorney General brief, page 77, citing 8 Tr 2489-2490.
[384] See Attorney General brief, page 78, citing 8 Tr 2494.
[385] See Attorney General brief, page 77.
[386] See Attorney General brief, pages 77-78.

began in 2018, but Schedule B5.7.1, line 11, does not report any spending in 2018, and neither the Part III documentation included in Exhibit AG-1.13, page 7, nor the business case executive summaries in Schedules N1.10 and N1.111 mention 2018 spending. More significantly, while Mr. Griffin's rebuttal testimony attempts to characterize the project as primarily a necessary "pre-step" required for a larger system replacement, Mr. Griffin did not make this claim in his direct testimony,[387] Schedule B5.7.1 classified this project as "Value Creation" rather than "Asset Health," and neither the Part III documentation in Exhibit AG-1.13, page 7, nor the business case executive summaries in Schedules N1.10 and N1.111 describe this as a required step to implement the S/4 system.

To elaborate on this last point, Exhibit AG-1.13, page 7, which was prepared for this case, describes this project as "transform[ing] the Purchase to Pay (P2P) process through the implementation of Ariba, improving the Company's supply chain organization's ability to procure and manage inventory." Project benefits are descripted "greater efficiency, . . . a more integrated approach to supplier and contractor management as well as aged inventory reductions . . ., [and] better integration between work management and purchasing capabilities." As the only statement under item e asking for a description of alternatives considered, and rationale behind the decision, this document states: "The rationale is that the current functionality in SAP for Purchase to Pay activities is being sunset in 2025, and SAP is replacing this functionality with Ariba. Transitioning to the new solution is the direction that was chosen when implementing SAP

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[387] See 8 Tr 2369.

10 years ago." This document also refers to Schedules N1.10 and N1.111 of Exhibit A-24 as "an in-progress draft of the Business Case." Schedules N1.10 and N1.111 identify this project as "clear growth and value creation strategy," and say nothing about S/4. Instead, while enumerating efficiency gains for DTE's supply chain management, "Ariba" is only mentioned in one of the line items, along with "Fieldforce," (see "key objectives," line 6) and one of the key objectives identified is "update existing Maximo SAP integration." Also troubling in reviewing the business case documents that are described as "in-progress," the total cost of the project reported on Schedule N1.10 is $9.2 million, while the total cost of the project reported on Schedule N1.111 is $2.8 million. Mr. Griffin provided no basis to reconcile these undated documents, and neither the $9.2 million nor the $2.8 million total cost figure can be reconciled with the total cost of $6.7 million reported in the Part III document. Additionally, while Schedule B5.7.1, line 11, reports 2019 spending as $1.9 million, Exhibit AG-1.13, page 7 shows 2019 spending as only $1.0 million.

This PFD finds that the Part III documentation does not match the referenced business case documents, and neither match Schedule B5.7.1 or Mr. Griffin's rebuttal description of this project. This PFD thus concludes that Mr. Griffin was insufficiently familiar with this project or its documentation to provide meaningfully support for the reasonableness and prudence of the proposed expenditures. This PFD finds Mr. Coppola's testimony persuasive, and recommends that the projected capital expenditures associated with the project be disallowed.

As the Attorney General argues, it is also troubling that DTE purports to be implementing "pre-steps" for a major system change that it has yet to provide a benefit-cost analysis for or obtain formal approval for. The Commission may want to consider further investigating the company's actual and planned expenditures in furtherance of this system, before resources are wasted.

b. Success Factors (Schedule B5.7.1, line 14)

DTE projects bridge period capital spending of $3.7 million and test year spending of $5 million for investments in DTE's human resources system, "SuccessFactors". Mr. Griffin testified that this is the continuation of a program the Commission approved $1.6 million toward in Case No. U-20162:

> The program will release features in the SuccessFactors platform in multiple areas through the implementation of four new modules adding to the base platform. One module will replace the current time and attendance system reducing the amount of time and effort required to accurately account for employee labor. A second module will focus on employee learning management and job qualifications, including those for employees maintaining a nuclear operations license and the associated reporting to the Nuclear Regulatory Commission (NRC). The current solution for this process is retiring and requires replacement. A third module will handle payroll transactions integrated with the Time and Attendance functions. Finally, the fourth module will handle workforce planning to increase budget precision and reduce the amount of manual effort required currently for compensation management.[388]

The Attorney General recommends a $9.1 million reduction as shown in Exhibit AG-1.14.[389] Mr. Coppola presented DTE's Part III documentation for this project in Exhibit AG-1.13, page 4. He noted a purpose of the project to project to "align compensation programs with business objectives, helping DTE model and manage competitive

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[388] See 8 Tr 2370.
[389] See Attorney General brief, pages 78-80.

compensation programs." He testified that with a projected total cost of $11 million, the project is "very expensive," and "could be pursued in a more cost-effective manner."[390]

In his rebuttal testimony, Mr. Griffin testified that the Commission provided $1.6 million in funding for this program in Case No. U-20162, and asserted that "[t]he current solution for this project is retiring and requires replacement . . . Allowing the software currently used for these processes to lapse into unsupported obsolescence is not a viable option for DTE."[391] He also testified that the company's plans had changed since his direct testimony was filed with the company's application, and DTE is now planning to expand the scope of the project and extend the project timeline:

> In my direct testimony earlier this year, I explained that in the test year we would invest $8.8 million in four modules for the program. Since my direct testimony, there has been a decision to expand this investment to include an additional module. Integrating this additional module into the investment plan has resulted in a schedule adjustment extending the timing of the compensation module beyond the test year. This re-planning will bring the total investment for this Program, including years outside the current test period, to an expected $15 million, with $11 million by the end of the test period. The Company understands that the increase in capital investment will need to be represented for inclusion in the rate base in a future case.[392]

He then presented additional detail on the modules that would be completed by 2022 and 2024. He objected that Mr. Coppola's testimony only addressed the compensation module, and also noted that the reduction in projected capital spending he proposed was $0.3 million greater than the company's projected amount.[393]

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[390] See 9 Tr 3001.
[391] See 8 Tr 2467.
[392] See 8 Tr 2467-2468.
[393] See 8 Tr 2469-2470.

Mr. Griffin also provided a discovery response in Exhibit AG-1.56 to explain his claim of obsolescence:

> There are two aspects to obsolescence. The first is where a product comes to a point in its lifecycle that the supplier chooses to stop making enhancements to that system. In this case the supplier has already halted any ongoing updates or enhancements to this current offering in favor of investments in a new product called Kronos. This means that for the remainder of its supported time period no new features or defect fixes will be available other than security patches. In very real sense that makes the current product end of life. In order to be ready to move to S/4 the company must implement Kronos prior to the S/4 conversion. The second is the total end of support. The current system will be completely unsupported in 2025.

DTE's brief essentially repeats Mr. Griffin's rebuttal testimony, characterizing Mr. Coppola's disallowance as "largely unexplained" because it focused on compensation management.[394]

In her brief, the Attorney General again argued that by including $1.6 million in rate base for this project in Case No. U-20162, the Commission did not "specifically approve" the capital expenditure because no party challenged it.[395] She further argued that the prior expenditure of $1.6 million does not justify the additional $10 million proposed for this project in the absence of economic justification, again noted that DTE has not approved the move to S/4, and again took issue with Mr. Griffin's assertion that failure to fund the program would allow the system to lapse into unsupported obsolescence:

> In the discovery response included in Exhibit AG-1.56, Mr. Griffin discussed what "unsupported obsolescence" means with regard to this specific system. From the response, it is clear that unsupported obsolescence means that the vendor is no longer issuing new updates to the system, the reason for which is that the vendor wants to sell DTE its new system,

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[394] See DTE brief, pages 77-79.
[395] See Attorney General brief, page 79.

> Kronos. This appears to be a form of planned obsolescence by software vendors and does not necessarily indicate that DTE's system is obsolete.[396]

In its reply brief, DTE disputes the Attorney General's concern with "planned obsolescence," arguing that regardless, it is not appropriate to simply keep using unsupported software.[397]

This PFD finds that DTE has failed to establish the reasonableness and prudence of its projected expenditures. First, DTE fails to acknowledge that its own Part III documentation, shown in Exhibit AG-1.13, page 4, reports total spending of $11.7 million from 2019 through 2021 and only mentions the compensation model. Second, Mr. Griffin testified that the project plans, including both total spending and timeline, had changed, but in his Exhibit A-43, he only presented copies of the same business case documents for which the executive summaries were provided in Exhibit A-24, Schedules N1.13, N1.14, N1.15, N1.114, N1.115 and N1.116. He did not provide either corrected or updated Part III information following the format of Exhibit AG-1.13, page 4. As with the P2P line item, DTE provided no benefit-cost analysis, and showed no consideration of alternatives. Exhibit AG-1.13, page 4 states as the rationale: "[I]f the business continues to use the existing SAP module, when Payroll moves to Success Factors in 2020 it will no longer be integrated." And, once again, the business cases do not support Mr. Griffin's claim that the current software used will "lapse into unsupported obsolescence." [398] Again, as with the P2P project discussed above, DTE's Schedule B5.7.1 of Exhibit A-12 characterizes the spending as "value creation." The business cases Mr. Griffin provided

[396] See Attorney General brief, pages 79-80.
[397] See DTE reply brief, pages 49-50.
[398] See 8 Tr 2468.

with his rebuttal testimony are Schedules HH3 through HH8 of Exhibit A-43. Page 2 of each of these schedules labels the project at issue as “discretionary spending.” None of the business case documents mention Kronos or the move to S/4.

Schedule HH3, labeled Success Factors Program 1, regarding the compensation model with a projected total cost of $1.3 million, states at page 2: “The current Compensation module is highly customized and expensive to maintain and is not integrated with the Success Factors platform.” On page 3 is says “Success Factors is an easier tool to use and is less time consuming to maintain.” On page 4 is says: “The Success Factors product was purchased in 2017. This business case for 2019 covers the implementation of modules purchased in 2017.” In the box for the alternative, “do nothing,” page 4 states: “The business will continue to use the existing SAP module, however, it is unrealistic once Payroll moves to Success Factors in 2020.” Schedule HH4, labeled Success Factors Program 2, addresses “badge scanning” for training at a projected total cost of $222,000. It states at page 2, “This business case is to enhance the capabilities of the Success Factors LMS that was implemented in June, 2019.” It states at page 4, in the box following the “do nothing” option: “Minimal will resort to using previous processes.” Schedule HH5, labeled as Success Factors Program 3, addresses a mobile time entry system with a total project cost of $6.5 million. On page 2 it states: “A more robust (e.g. mobile time entry and approval) and centralized time management system is required as the current on-prem solution is aging and no longer support the mobile workforce. This business case represents the implementation of SAP Success Factors Workforce time and Attendance Management Software.” On page 4, under the “do nothing” option, it states: “Doing nothing will impede the ability to have mobile time entry and a more robust overtime monitoring solution." Schedule HH6, confusing labeled "Success Factors 1", also addresses training, with a reported total cost of $1.7 million. On page 2, in addition to repeating the statement quoted above from the "Success Factors Program 3," and citing the business case numbers included in Schedules HH6, HH7, and HH8, the document states:

> The HR organization uses many applications in disparate environments to manage employee qualifications, health requirements, and monitor training requirements. These systems SAP, Aspire and Nantel are not integrated making it difficult to report, track status and measure the organization. Fermi has more stringent requirements regulated by INPO for training and health measurements. To meet these additional needs the business is using custom applications to schedule, monitor and report requirements.

Schedule HH7, labeled Success Factors 2, appears to be a different version of Schedule HH5, with a $5 million total project cost rather than the $6.5 million reported on Schedule HH5. This document, at page 4, states: "Doing nothing will impede the ability to have mobile time entry and a more robust overtime monitoring solution." Schedule HH8, labeled SuccessFactors 3, focuses on a recruiting, with a projected total cost of $313,000.

While these project goals are not unreasonable, the documents do not appear to support either the total spending projected for the project components,[399] or the reasonableness and prudence of that spending. Since DTE acknowledges the project scope and timing have changed, since DTE did not provide accurate Part III information for this project, and since the project documents DTE did provide do not support the

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[399] Recognizing that Schedules HH5 and HH7 appear to cover the same thing, with two different cost estimates, using the $6.5 million figure from Schedule HH5 shows total project spending of only $10 million, while Exhibit AG-1.13, page 4, shows total projected spending of $11.7 million, and Schedule B5.7.1 shows 2019 through end-of-test-year spending of $12.5 million. Note that Schedule B5.7.1 also reports 2018 spending of $1.9 million, but none of the project documents include 2018 spending, and all have project start dates in 2019 or 2020.

claimed obsolescence or the spending projected on line 14 of Schedule B5.7.1, this PFD finds Mr. Coppola's testimony persuasive that the projected expenses should not be included in rate base.

c. Web Portal Rebuild and Transformation (Schedule B.7.2, line 8)

DTE projects bridge period capital expenditures of $3.8 million and test year capital expenditures of $13.4 million for this project on line 8 of Schedule B.7.2, which DTE includes in the Customer Service Project category. Mr. Griffin explained this project as a $17.2 million complete redesign of the company's web portal "to improve ease of access, simplify navigation, and ensure that the interactions that the customer most often uses and finds value in are clearly front and center in the experience," as well as to "[bring] the Portal architecture up to current industry standards."[400]

The Attorney General recommends a $17.8 million reduction to capital expense projections for this project as shown in Exhibit AG-1.14.[401] Presenting DTE's business case document in Exhibit AG-1.13, Mr. Coppola testified that DTE plans to spend more than $23 million from 2019 to 2022 on this project to "provide the company with forms to track safety data, rich data metrics in dashboard format, reports, analytics, graphs in an easy one stop shop for Corporate Safety, leaders and employees to track their area's safety compliance."[402] Again he noted that DTE did not identify any financial benefits, further explaining:

> If the Company wants to spend more than $23 million on a system upgrade, it has an obligation to show how safety will be improved and safety incidents

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[400] See 8 Tr 2377.
[401] See Attorney General brief, pages 84-86.
[402] See 9 Tr 3002.

> will be prevented, along with financial benefits that justify the capital expenditures. The Company has not presented any of that.[403]

In his rebuttal testimony, Mr. Griffin acknowledged that he had provided "an incorrect narrative in the Top 25 highest cost IT/OT project list," referencing Exhibit AG-1.13, page 5.[404] He asserted that "[t]he correct description and data supporting the program was included as Exhibit A-24, Schedule N1.29, which is the Executive Summary for this business case."[405] He testified that the company's website is no longer robust enough to support the variety of features expected in a modern digital experience:

> We currently do not meet our Customers' expectations using the tools available in the current site implementation. This results in the website having the lowest customer satisfaction rate of any of the Company's digital channels at 72% and contributes to the nearly 5 million calls being driven to the contact center each year.
>
> With the dedicated Web Transformation project, we will improve the performance of the site by moving to a more robust cloud architecture improving the current load times and customer experience. Efforts currently invested in enhancing this channel or responding to its shortcomings, will be spent focusing on other customer serving initiatives.[406]

He also objected that Mr. Coppola's proposed adjustment totaling $17.8 million is $0.5 million more than DTE proposes for bridge and test year capital spending. On cross-examination, Mr. Griffin also testified that promoting web-based self-service for customers could "potentially" reduce "live agent" phone calls.[407]

In her brief, the Attorney General argued that no weight should be given to the savings figures Mr. Griffin provided on cross-examination, arguing "they are completely

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[403] See 9 Tr 3002-3003.
[404] See 8 Tr 2475.
[405] See 8 Tr 2475.
[406] See 8 Tr 2476.
[407] See 8 Tr 2509-2511.

unsupported by DTE and were provided for the first time on the stand," and that "Staff and Intervenors had not chance to vet the Company's internal savings forecasts."[408] The Attorney General also addressed Mr. Griffin's rebuttal testimony regarding webpage loading rates at 8 Tr 2476 and his further response to discovery projecting a reduction in average load time from 6 seconds to 3 seconds. The Attorney General argued that this reduction is not sufficiently perceptible to customers to justify a portion of the $17 million to be spent.[409]

DTE's brief tracks Mr. Griffin's rebuttal testimony, contending that because Mr. Coppola "relied upon the Top 25 narrative rather than the Executive Summary for the business case. . . some of Mr. Coppola's criticisms lack relevance to the actual project."[410] In its reply brief, DTE responds to the Attorney General's arguments regarding the cost-savings estimates Mr. Griffin provided in his cross-examination testimony, arguing "the AG should not be heard to complain about the answers she got to her own cross-examination."[411]

This PFD finds that DTE has not supported the reasonableness and prudence of its projected expenditures on this project, and concludes that the Attorney General's recommendation to exclude DTE's projected capital spending for this project should be adopted. Once again, Mr. Griffin seemed insufficiently familiar with the contents of his own supporting documentation. While inserted in the business outcome box on Schedule N1.29 is the statement he quoted indicating the company "will invest $17 million in the

[408] See Attorney General brief, page 85.
[409] See Attorney General brief, pages 85-86.
[410] See DTE brief, page 82, also citing Griffin, 8 Tr 2475.
[411] See DTE brief, page 52, also citing the "invited error doctrine".

Web-Portal Re-build and Transformation project," the document itself reports total costs over the time period 2020 through 2023 of $32 million. Even though Mr. Griffin identified that the "narrative" of the Part III documentation was incorrect, he did not attempt to reconcile the $23.1 million project total presented in that document with the $17 million in his testimony and in the "business outcome" box on Schedule N1.29, or with the $32 million total presented in the cost detail in that schedule.

Whenever Mr. Griffin realized the information in Exhibit AG-1.13, page 5, was incorrect, he made no effort to provide a corrected version to the parties. DTE's effort to claim that Mr. Coppola should have consulted Schedule N1.29 is unhelpful, since that document contains information that is clearly at odds with Mr. Griffin's testimony. This PFD notes that item c of the Part III filing requirements calls for benefits in dollars, item e calls for a description of alternatives considered, and item f calls for a benefit-cost ratio. As noted above, DTE provided no quantification of benefits, no analysis of alternatives, and no benefit-cost analysis in support of any of the IT projects the Attorney General disputed. Mr. Griffin's assertion that "the correct description and data supporting this program was included as Exhibit A-24, Schedule N1.29,"[412] is simply not true. There is no "data", no discussion of alternatives in that schedule, and no benefit-cost analysis.[413]

This PFD finds no explanation in the record to support DTE's assertion in Exhibit AG-1.13, page 5, that a benefit-cost analysis is "not applicable" to a project projected to cost $32 million over a three-year period per Schedule N1.29, or $23.1 million over a two-

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[412] See 8 Tr 2475.
[413] It should also be noted that DTE has several other IT projects that appear to be aimed at improving customer experiences with DTE's website or promoting self-service. See Exhibit A-24, e.g. Schedules N1.24, N1.25, N1.28, N1.32, N1.125.

year period per Exhibit AG-1.13. Mr. Griffin's attempt to supply savings estimates on the stand in cross-examination is unhelpful and unreliable, since, as the Attorney General argues, no party was able to evaluate those claims under the operative schedule of this case. The Commission has given DTE ample opportunity through the filing requirements and through its instructions in Case No. U-20162 to organize its evidentiary presentation for IT programs, and for this project, in failing to provide consistent, useful, and timely supporting information, it clearly failed to take advantage of that opportunity.

d. Bill Redesign (Schedule B5.7.2, line 17)

Mr. Griffin testified that DTE is proposing to spend $5.5 million to redesign its customer bills "in a format that provides key information to the customers in an easy-to-read format as well as accommodate additional bill presentment requirements that are emerging for alternate rates and services."[414] He further asserted that "once implemented," the redesigned bill "will be the foundation for the bill metering pilot to experiment with rapidly adding or changing content on the new standard-appearance bill."[415]

Staff and the Attorney General take issue with DTE's projected bill redesign capital expenditures, with $1.3 million projected for the bridge period and $4.3 million projected for the test year.[416] DTE's Part III documentation for this project is included in Exhibit AG-1.13, page 6 and the executive summary of its business case is Schedule N1.34 of Exhibit A-24. As part of her analysis, Dr. Wang asked DTE how it would measure success

[414] See 8 Tr 2379.
[415] See 8 Tr 2379.
[416] See Staff brief, pages 23-24; Attorney General brief, pages 80-82.

for this program. As shown in Exhibit S-12.6, Mr. Griffin responded: "The key metrics for this project will be to provide clear billing to DTE customers thus reducing MPSC billing complaints." As also shown in Exhibit S-12.6, Mr. Griffin also responded that the expected impact of the program on the identified metric "is not quantifiable until a solution is in place." Dr. Wang also asked DTE what percentage of customers expressed dissatisfaction with the current bill design; as shown in exhibit S-12.7, Mr. Griffin responded: "While the total number of customers expressing dissatisfaction is not tracked in the required manner, there have been 17 MPSC complaints associated with bill presentment in 2019 and 45 complaints in 2018." She testified that the statistics DTE provided show that fewer than one-hundredth of 1% of customers complained in 2018 and 2019.[417] She recommended that the Commission reject the capital expense projections totaling $5.5 million, and that any costs related to bill redesign in future cases undergo a prudency review.

Mr. Coppola again noted that DTE's project documentation does not identify any financial benefits or cost savings in support of projected expenditures of $7 million through 2021.[418] He also considers the value of the project "questionable," noting that in 2017, DTE completed implementation of its Customer 360 system at a cost of $200 million:

> That system included a new customer billing system and improvements to customer billing and bill presentment. It is difficult to understand why, two years later, the Company is seeking to redesign the customer bill at an additional cost of $7.0 million when there are more pressing needs to rebuild electrical infrastructure. No matter how the Company designs its bill, it is a given that some customers will have confusion or dissatisfaction with the bill presentation. No specific evidence has been presented by the company

[417] See 9 Tr 3369.
[418] See 9 Tr 3003.

> to show that there is broad-based dissatisfaction or confusion with the format of the bill to justify spending $7 million over the next two years, particularly when there are far more pressing needs for capital.[419]

The Attorney General recommends a reduction in projected spending for this project of $5.7 million as shown in Exhibit AG-1.14.

Mr. Griffin's rebuttal testimony acknowledged that a key metric for the bill redesign is MPSC complaints, but asserted that it is not the sole indicator of success or the driving factor, presenting a summary of what he labeled DTE's "case for change" at 8 Tr 2471-2472. In this testimony, he identified the opportunity to avoid the manual adjustment of 2,000 bills per week, and potential cost savings from reduced customer calls. He also noted that for this line item as well, Mr. Coppola's proposed adjustment is slightly greater (by $0.2 million) than the company's bridge and test year projected spending.[420]

Responding in cross-examination, Mr. Griffin further testified that the bill redesign is an opportunity for DTE to reduce its printing and materials costs in addition to avoiding the time spend on manual bill adjustments.[421] In its brief, DTE repeated Mr. Griffin's rebuttal testimony.

In her brief, the Attorney General addressed Mr. Griffin's rebuttal testimony, and his responses on cross-examination. She cited the examples of bill adjustments DTE provided in Exhibit AG-1.57, arguing:

> At base, the AG does not understand why DTE is unable to make a programming fix to the current bill, where the adjustments discussed are footnoted somewhere in the bill or next to the explanation box, providing the very details Mr. Griffin provided during cross examination. Additionally, it would be costly and imprudent to spend $7 million to implement a

[419] See 9 Tr 3004.
[420] See 8 Tr 2472.
[421] See 8 Tr 2496-2497.

> programming fix to redesign a bill for 2,000 bills that require a few more details. While there may be some other tangential benefits, DTE did not lay those out in testimony or present any monetary analysis that it would be worth the millions of dollars of increased customer costs. Finally, DTE did not present any evidence about other options the Company considered to address the problem at a lesser cost.[422]

Staff argued that DTE had the opportunity to provide "motivations and metrics of success" for the program in its original testimony, exhibits and discovery responses, to allow Staff time to investigate the information. Staff emphasized DTE's response as shown in Exhibit S-12.7, and further argued that DTE did not support any of the assertions made in rebuttal with data to show the investment reasonable and prudent.[423]

In its reply brief, DTE further contended that Staff's objection to reliance on DTE's rebuttal evidence contravenes the law:

> [T]he law provides that the Commission must make its decisions on the whole record, which includes rebuttal testimony, live testimony elicited during cross examination, and all exhibits admitted into the record, regardless at which stage of the proceedings the evidence was produced. The Commission cannot merely ignore record evidence.[424]

This PFD finds Dr. Wang's and Mr. Coppola's testimony persuasive that DTE has not established the reasonableness and prudence of its proposed expenditures on bill redesign. As Dr. Wang concluded, DTE had the opportunity to provide additional metrics of success for the program and did not. As Mr. Coppola testified, DTE had the opportunity to provide a benefit cost analysis in support of its projected expenditures and did not. This is shown by Exhibit AG-1.13, page 6, in which DTE presented no quantification of benefits, no discussion of alternatives that would justify the amount of spending

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[422] See Attorney General brief, pages 81-82.
[423] See Staff brief, page 24.
[424] See DTE reply, page 50.

requested, asserting instead that "do nothing will exacerbate the situation," and in which DTE stated "not applicable" when asked for a cost-benefit analysis.

In part because DTE had ample opportunity to provide an analysis of potential savings associated with its proposed project as part of its filing, this PFD finds that Mr. Griffin's offer of projected savings figures is unpersuasive to establish that the project has a cost-savings justification. Mr. Griffin's response to Staff's discovery in Exhibit S-12.6 is also concerning, because there Mr. Griffin asserted that the expected impact was "not quantifiable until a solution is in place."

Additionally, as with other line items in DTE's IT schedules, the documentation DTE offers has not been reconciled to the projected expenses in Schedule B5.7.2 of Exhibit A-12. DTE's projected capital expenditures for this item are $1.25 million for the bridge period ending April 2020, and $4.27 million for the projected test year, while Exhibit AG-1.13, page 6, states a total project cost of $7 million over two years and Schedule N1.34 of Exhibit A-24 states a total project cost of $10.1 million over three years, $9.3 million of which is attributed to capital. The Attorney General asked Mr. Griffin on cross-examination about future costs outside of the costs included in the company's capital expense projections:

> Q. And the total cost of this project is at least 7 million through the end of 2021; is that correct?
>
> A Based on the exhibit that I filed, A-12 Schedule B7.2, it indicates that during the bridge and test period for this particular rate case, that the total is on the order of $5.5 million.
>
> Q Do you expect ongoing costs for this project?
>
> A Are you asking do I expect the costs to exceed this, or that there would be additional costs after the cost indicated?

Q Additional costs after the cost indicated.

A So there are two aspects to this particular program. There's the bill redesign, which is the question you're asking. Once the bill redesign has been complete, the bill would be in a format where that would not necessarily require any additional investment; however, much like our existing bill, if there are Commission orders, if there's any voice of the customer or business justification for changing that bill, that could incur additional costs in the future. It's not part of the plan for this particular project.[425]

Once again, Mr. Griffin seemed to lack familiarity with the project documentation DTE relies on.

e. Digital Engagement Group Establishment (Schedule B5.7.2, line 23)

DTE proposed bridge period capital spending of $2.3 million and test year capital spending of $6.9 million to establish a "digital engagement group." Mr. Griffin testified that this will be "a new organization dedicated to improving the Company's customer experience."[426] He provided the following additional description:

During this period, capital investments will be made in three areas: 1) Hardware and software will be purchased to construct copies of our existing Customer system's production environments. Once implemented, these environments provide the DEG team with dedicated development and test systems. 2) The team will produce designs for customer system enhancements specifically targeted at improvements in the customer experience. Once completed and approved these designs will be implemented by the IT Customer Service Team in the form of projects or enhancements. 3) During the period the DEG Team will produce, at minimum, the Designs for the Transformational Web, the replacement Mobile application, and a solution allowing customers to track all of their interactions with the Company.[427]

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[425] See 8 Tr 2495-2496.
[426] See 8 Tr 2382.
[427] See 8 Tr 2382.

Staff and the Attorney General recommend that the Commission exclude the projected spending from rates in this case.[428] DTE's business case documentation for this project is included in Exhibit AG-1.13. Dr. Wang cited Mr. Griffin's discovery response in Exhibit S-12.9 stating that the business case for this projected expenditure "is currently under development," so prioritization scores are not available.[429] She recommended a complete disallowance of the projected expenditures due to the uncertainty in the objectives, benefits, and costs.[430]

Mr. Coppola recommended excluding the 2020 projected expenditure of $9.2 million as shown in Exhibit AG-1.14:

> The benefits stated by the Company are that the DEG and this system will somehow improve the customer experience, but it is unclear what that means. No financial benefits have been identified. As stated above, the cost to develop this group and computer systems is $9.2 million to be spent during the year 2020.[431]

In his rebuttal testimony, Mr. Griffin objected to these recommendations, disputing that there are no clear benefits, and presenting statistics on the utilization of the company's digital channels. He identified "transaction optimization efforts" undertaken by the company to show the importance of the digital channels.[432] In cross-examination, Mr. Griffin further asserted that DTE had "done some work around what the cost savings could be" associated with the company's proposal, and provided certain estimates.[433]

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[428] See Staff brief, pages 21-22; Attorney General brief, pages 82-84.
[429] See 9 Tr 3370.
[430] See 9 Tr 3370-3371.
[431] See 9 Tr 3000.
[432] See 8 Tr 2474.
[433] See 8 Tr 2501-2512.

In its brief, DTE repeats Mr. Griffin's rebuttal testimony and savings figures,[434] and DTE relies on this presentation in its reply brief.[435]

In its brief, Staff argued that the costs should be disallowed until they are more sufficiently developed. Addressing Mr. Griffin's rebuttal testimony, Staff noted that the "business case" Mr. Griffin presented in rebuttal was not developed when the case was filed, or during discovery, citing Exhibit S-12.9, and further argued:

> In rebuttal, Company witness Griffin reiterated the mission of the Digital Engagement Group Establishment. He described the areas where the project will focus, namely: (1) Move In Move Out; (2) Outage; (3) Payments, Billing, Collections; and (4) Service Capabilities (8 TR 2473-74). Though he provided some statistics on the current digital interactions for most of these categories, the details Company witness Griffin provided in rebuttal still fail to clarify the benefits and costs associated with the Digital Engagement Group project. The information he provided does not overcome the fact that the business case is not well developed.[436]

Additionally, Staff argued that the estimated benefits Mr. Griffin provided in cross-examination are calculated from the current statistics regarding digital customer engagements, and reflect the estimated benefits from current digital interactions and not potential benefits realized from the Digital Engagement Group establishment.[437]

In her brief, the Attorney General focused on one of Mr. Griffin's responses on cross-examination to support her argument that the scope of the projected expenditure is vague:

> When asked whether the features that he mentioned in rebuttal could be implemented within the specified timeframe and budget or whether there may be additional costs, Mr. Griffin indicated that there may be additional

[434] See DTE brief, pages 80-81.
[435] See DTE reply, page 51.
[436] See Staff brief, page 22.
[437] See Staff brief, page 22.

projects that would stem from initial efforts that would incur costs beyond the test year. The actual response on cross examination is instructive:

> The DE Group's responsibility is to work all of these areas, it's not wholly responsible for the projects that would stem from their efforts. As an example, the Digital Experience Group would be the front end of the design process that would design some of the projects that are upcoming. So while it would work often on the front end of these projects, the projects themselves might go past the time period that this is expressed for. So they're basically a design and function organization. The IT area would then implement the projects when it went into implementation. DEG would pick it back up when it's at the implementation has begun, and therefore we would be collecting customer feedback on the designs and so on. There's a -- They don't operate the entire project themself, so there would be investment in these projects potentially beyond the test year.

This is a very vague and open-ended answer to the question of additional costs related to the Digit Engagement Group project and leaves open the possibility for ever increasing and expanding costs. As the Company has failed to quantify any cost savings from having customers do more transactions on their own online, and is unable to identify how much additional spending will be required and over what timeframe, the AG continues to recommend that the Commission disallow all of the requested cost recovery for the Digital Engagement Group Establishment project.[438]

This PFD finds that DTE has failed to justify the reasonableness and prudence of its projected capital expenditures on the Digital Engagement Group. DTE's effort to present a new "business case" to support the expenditures through Mr. Griffin's rebuttal testimony is not proper. The Commission has previously made clear that the utility may not reserve line items of capital as a placeholder, only to explain its actual plans in the rebuttal phase. Not only did DTE decline to provide a benefit-cost analysis or a consideration of alternatives in its Part III documentation as shown in Exhibit AG-1.13, page 3--reciting merely "[t]he rationale for this initiative is to upgrade customer experience

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[438] See Attorney General brief, pages 83-84.

and document all processes," and that a cost-benefit ratio is "not applicable"—but DTE also declined to provide Staff with even a prioritization score for this project as shown in Exhibit S-12.9, stating that the "business case is currently under development." The "in progress draft of the Business Case" referred to Exhibit AG-1.13, page 3, refers only to Schedule N1.37 of Exhibit A-24, which does not include even the detail included in the "executive summaries" found in that exhibit for other projects because it does not have any cost detail. As Staff argues, it is clear that the Digital Engagement Group is intended essentially to assist on other ongoing projects, and the benefits Mr. Griffin has claimed for the group are the benefits associated with those other projects. Thus, the Digital Engagement Group "scope statement" in Schedule N1.37 states:

> The team will produce designs for customer system enhancements specifically targeted at improvements in the customer experience. Once completed and approved these designs will be implemented by the IT Customer Service Team in the form of projects or enhancements.

And further:

> During the period, the DEG Team will produce, at minimum, the Designs for the Transformational Web, the replacement Mobile application, and a solution allowing customers to track all of their interactions with the Company.

A cursory review of DTE's filing in this subject area shows other line items for these activities. The "transformational web", for example, with its own projected expenditures, was discussed in subsection c above.

f. Fixed Bill Pilot (Schedule B5.7.2, line 34)

Several parties have raised objections to DTE's proposed fixed bill pilot. DTE projected IT capital expenditures of $.7 million for the bridge period and $2.1 million for the test year in line 34 of Schedule B5.7.2. Mr. Griffin testified to the proposed expenditures; Mr. Clinton addressed the pilot program.[439] For the reasons discussed below in the Rate Design section of this PDF, DTE has not established that its proposed fixed bill pilot is reasonable, and thus, the projected capital expenditures should be removed.

g. 2019 Emergent Capital (Schedule B5.7.5, line 1)

As part of its Technology and Architecture category, DTE projects spending $5.1 million in the bridge period. The executive summary business case document is Exhibit A-24, Schedule N1, page 158. Mr. Griffin testified that the money would be used "to dedicate capacity to applied innovation technology," acknowledging that the Commission disallowed a portion of the utility's requested funding for this program in Case No. U-20162, but asserting that DTE actually invested $4 million, and detailing the programs that were funded.[440]

Staff recommends a reduction of $3.13 million to this amount to exclude projected bridge period projected spending above the amounts spent so far.[441] Dr. Wang objected to the indeterminate foundation of the expense projections for this category:

> Given the business case objectives are to be determined as each initiative is approved, there is great uncertainty in these projects, not only in scope, benefits, and usefulness, but also project costs. Due to the guaranteed recovery of these cost projections once approved, it is inappropriate for the Company to recover these costs in rates given this uncertainty.[442]

In his rebuttal testimony, Mr. Griffin testified that the 2019 Emergent Project and the Applied Innovation project, discussed in subsection h below, are really the same

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[439] See 8 Tr 2387.
[440] See 8 Tr 2408; 8 Tr 2432; 8 Tr 2455-2460.
[441] See Staff brief, pages 25-27, and Exhibit S-12.5.
[442] See 9 Tr 3367.

project. He acknowledged that the Commission agreed with Staff in Case No. U-20162 that the "emergent project" investment was speculative, and reduced the company's projected spending by $6.6 million. He further acknowledged that DTE did not have historical data to support its investment in that case, but contended that in this filing, citing his testimony at 8 Tr 2408-2409, he demonstrated that the company's projection method was sound. For 2019, he asserted "enough data is available to demonstrate prudent and planned expenditure in alignment with my direct and rebuttal testimony in U-20162, and my direct testimony in this case."[443]

In its brief, DTE addresses this jointly with the Applied Innovation project discussed below. Citing Mr. Griffin's rebuttal testimony, DTE argues that the 2019 spending "did not provide to be speculative as Staff suggested," contending that:

> As of November 2019, enough data is available to demonstrate prudent and planned expenditures in alignment with Mr. Griffin's testimony in Case No. U-20162 and his direct testimony here (Exhibit A-12, Schedule B.7.5). Mr. Griffin provided additional quantified detail demonstrating that the Applied Innovation project is similarly non-speculative (8 T 2479-80; Exhibit A-24, Schedule N1.69)[444]

DTE also contends that Mr. Coppola's recommendation "appears to be based on a misunderstanding of the program," again citing Mr. Griffin's rebuttal testimony:

> Mr. Griffin explained that DTE Electric does not intend to spend $8 million to develop or otherwise acquire a tracking tool. The Company is instead broadening its focus on electric reliability through emergent and active initiatives in the innovation pipeline. For example, the use of drones is expected to yield operational productivity, specifically with considerable improvements in pole top inspection and storm response (8 T 2480).[445]

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[443] See 8 Tr 2479.
[444] See DTE brief, page 83.
[445] See DTE brief, page 84.

In its reply brief, DTE relies on its initial brief.[446]

Citing Schedules N1.158 and N1.69, DTE's "business case" executive summaries for these programs, Staff argued that the business cases are highly speculative in nature and further, that costs cannot be accurately estimated for work that is not yet determined in goals, scope, or key objectives, citing Dr. Wang's testimony. Addressing Mr. Griffin's rebuttal, Staff disputed that DTE's spending projection can be described as a forecast, labeling it a project budget, and further disagreed that initiatives Mr. Griffin listed prove that the initiatives are not speculative:

> It is not the number of initiatives that proves the program value. What proves value is the project objectives and achieved results. However, the Company provides no data that assesses the success of the historical projects conducted under the 2018 Emergent or 2019 Emergent programs. Similarly, no data has been provided regarding the goals and success metrics for the potential or active initiatives under either the 2019 Emergent or Applied Innovation programs.[447]

Staff also argued that expenditures cannot be known or predictable if the initiatives are to be determined "as they emerge," further arguing:

> No guidelines or overall project goals were provided that help check the adequacy or effectiveness of any investments made under this program. Therefore, little weight should be given to the Company's ability to spend down the allocated funds. The Company's ability to spend an arbitrary program budget is not proof of its ability to use funds prudently or reasonably.[448]

Staff continues to accept the $1.96 million in 2019 expenditures it was able to review, with the resulting proposed disallowance $3.1 million for 2019, and $0.5 million for the bridge period, and $4 million for the test year.

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[446] See DTE reply brief, pages 52-53.
[447] See Staff brief, page 26.
[448] See Staff brief, pages 26-27.

This PFD finds Dr. Wang's testimony and Staff's arguments persuasive, and recommends that the Commission adopt Staff's recommended reduction in the projected capital spending for the 2019 "emergent capital" line item.

h. Applied Innovation (Schedule B5.7.5, line 2)

As shown on line 2 of Schedule B.7.5, DTE proposes to spend $.5 million in the bridge period and $4 million in the test year for this project. Mr. Griffin described this as "identical in concept to the 2019 Emergent project," but for projects that will occur in 2020 through the end of the projected test year.[449] Staff and the Attorney General recommend that the Commission reject DTE's projected spending for this project.[450] In addition to the executive summary document in Exhibit A-24, Schedule N1, page 69, DTE's business case documentation for this item is in Exhibit AG-1.13. Dr. Wang objected to the uncertainty in the business objectives for the proposed expenditure in recommending that rate case funding be rejected:

> The Applied Innovation business case is to "support achieving improved performance….by delivering approved innovative business benefits in a rapid manner." Its key objectives are uncertain as their "[a]lignment [is] to be determined as each initiative is approved."[451]

Mr. Coppola objected that the only benefit of the project is identified as "the delivery of approved innovative business benefits in a rapid manner," with no financial benefits identified.[452] He recommended a reduction in DTE's projected IT capital spending of $5.3 million as shown in Exhibit AG-1.14 for 2020 and 2021.

[449] See 8 Tr 2408-2409.
[450] See Attorney General brief, pages 86-89; see Staff brief, pages 25-27.
[451] See 9 Tr 3367-3368.
[452] See 9Tr 2998.

As noted above, Mr. Griffin's rebuttal testimony explained the name change from "emergent capital" to "applied innovation" beginning with 2020. He also disputed that the program is speculative, asserting that there are 39 "potential and active initiatives," and that DTE "will allocate the $8 million total (2020 + 2021) to potential and emergent projects from the overall innovation pipeline," also citing Schedule N1.69.[453] Again, he objected to Mr. Coppola's total $5.3 million adjustment as shown in Exhibit A-1.14, in comparison to the $4.48 million reflected in line 2 of Schedule B5.7.5.

This PFD finds Dr. Wang's and Mr. Coppola's testimony persuasive that funding for 2020 and 2021 "applied innovation" should not be included in rate base. As with the "emergent capital" discussed above, DTE has failed to establish plans for the projected expenditures, but intends to develop plans once the funding is provided. The executive summary business case in Schedule N1.69 of Exhibit A-24 states that the project is: "To support achieving improved performance (in existing operational process gaps, metrics, etc.) by delivering approved innovative business benefits in a rapid manner." The only "key objective" stated is "Alignment to be determined as each initiative is approved." The supplemental information supplied by Mr. Griffin in rebuttal, while untimely and thus not able to be reviewed by the parties, also references other projects for which DTE has separately requested funding.

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[453] See 8 Tr 2479-2480.

i. Network-Advanced Metering Infrastructure Enhanced Support (Schedule B5.7.7, line 8)

Mr. Griffin testified that DTE is projecting a $4.7 million expenditure to enhance its "private mesh network" for AMI meter data collection and transportation:

> The components of this network are on a 7-year asset-replacement schedule and the funding for this program covers the capital investment needed to replace these components as they age out. Kept up to date, these devices will perform more reliably, require less maintenance, and maximize availability, helping the Company to provide better service to our customers. Additionally, the Commission included this program in the rate base in Case No. U-20162 and the capital spend included in this case is incremental and builds upon work/spend included in U-20162.[454]

DTE included the executive summary business case for this project as Schedule N1.172 of Exhibit A-24.

Staff objected to DTE's historical and projected expenditure for this project.[455] Dr. Wang explained that although the purpose of the program is to improve the AMI mesh read rate, it is already at 99.22%, well above the service quality standard of 85% in R 460.724(d). She testified that Staff recommended excluding further expenditures for this program in DTE's last rate case, and thus Staff recommends excluding a portion of historical expenditures as well projected expenditures in this case:

> In 2018, $1,431,016 was approved for rate base for this program. This approved amount is removed from the disallowed historic spending. As such, only $872,984 is disallowed in the historic period for this program. In addition, the full bridge and test year amount of $2.465 and $2.2 million, respectively, is disallowed for this program.

[454] See 8 Tr 2418.
[455] See Staff brief, pages 27-30.

In his rebuttal testimony, Mr. Griffin asserted there are multiple reasons the expense is prudent and timely in addition to approving the mesh read rate.[456] He addressed DTE's discovery responses to Staff, which included in Schedule HH1 of Exhibit A-43, acknowledging that DTE indicated that 100% of the spend was related directly or indirectly to the read rate, but testified "[t]his response should not shift the focus of this investment from Asset Health to improved read rates."[457] Ms. Robinson also provided rebuttal testimony addressing the mesh read rate, in support of DTE's proposed distribution system spending, as discussed above.[458] In its brief and reply brief, DTE relies on its rebuttal testimony, characterizing Staff as misunderstanding that DTE's expenditures are to sustain read rates rather than to improve them. See DTE brief, pages 84-85, DTE reply, page 53.

In its brief, Staff cites Exhibit S-12.9 in arguing that its recommended disallowance is based on the company's admission that 100% of the project is directly or indirectly intended to bolster the AMI mesh read rate from 99.2% to 99.5%. Addressing Mr. Griffin's rebuttal, Staff argued:

> If deployed network assets are being identified and replaced on a planned cadence, the Company does not provide justification for why this cadence is necessary, what components are being replaced, and how replacement of these devices impact AMI mesh network read rates. This information is missing in the Company's original testimony, discovery responses, and rebuttal. None of the Company documents provide any data or analyses demonstrating the benefits from the incremental improvement of 0.3% in the AMI mesh read rate, or make a clear distinction between maintenance of the current mesh read rate of 99.2% and the 0.3% incremental increase when discussing costs. No estimated benefit information is provided.[459]

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[456] See 8 Tr 2481-2483.
[457] See 8 Tr 2482.
[458] See 9 Tr 2631-3632.
[459] See Staff brief, page 29.

The RCG supports Staff's proposed disallowance in its brief. [460]

This PFD finds Dr. Wang's testimony and Staff's arguments persuasive. DTE's own business case document supports Dr. Wang's conclusion that DTE's project is designed to increase the mesh read rate. Schedule N1.172 states: "Enhanced AMI Mesh supporting the Return to Health Roadmap. Improved Asset Health and Asset Compliance Metrics." Under "key objectives" the document indicates that analyses will occur before implementation, testing and incorporation:

> 1) SIN-18-013-NAES-F001 – Projection of new AMI equipment load to the existing Mesh
>
> 2) SIN-18-013-NAES -F002 – Analysis to determine the impact of the AMI data and processing requirements on the existing environment and propose new or enhanced network equipment to resolve the increase of capacity requirements
>
> 3) SIN-18-013-NAES-F003 – Implementation and testing of the identified hardware/software necessary to enhance the AMI Mesh
>
> 4) SIN-18-013-NAES-F004 – Incorporation and testing with the AMI Team to ensure network connectivity meets requirements

j. Advanced Customer Pricing Pilot

Through Mr. Isakson's testimony, Staff initially objected to DTE's proposed pilot and thus recommended that the projected capital expenses of $5.9 million be excluded from projected rate base.[461] In its brief, page 15, Staff indicates that following the Commission's November 14, 2019 approval of the pilot in Case No. U-20602, it no longer objects to including the projected expenditures in rate base.

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[460] See RCG brief, pages 34-35.
[461] See 9 Tr 3126.

k. Future Recommendations

Dr. Wang presented the following recommendation:

> In the future, Staff recommends that for any business case where the program objectives are not determined until each initiative is approved, the Company should provide evidence of prudent and reasonable spending for historic and year to-date spending when submitting the rate case. Greater explanation of each initiative should occur, where the initiative objectives and benefits are concisely and clearly stated and quantified in a way to allow an assessment of its value.[462]

In its brief, Staff also asks that the Commission emphasize the requirements it already has in place. Based on the foregoing analysis, this PFD finds more broadly that DTE did not make an organized or coherent presentation in support of its IT capital expenses, and did not fully comply with the Commission's filing requirements. This PFD recommends that the Commission provide guidance, yet again, regarding DTE's obligations to support its projected capital spending in this area, including adopting Staff's recommendations and directed DTE to abide by the requirements already in place.

7. Charging Forward

In Case No. U-20162, the Commission authorized DTE to create a regulatory asset for the purpose of deferring and amortizing Electric Vehicle (EV) program costs, specifying that DTE would recover the reasonable and prudent deferred costs through a five-year amortization, after the costs were reviewed. Issues related to the regulatory asset balances and amortization expense are discussed in section VII below. As shown in Schedule B5.9 of Exhibit A-12, DTE also included a projected capital expenditure for

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[462] See 9 Tr 3368.

the Charging Forward program of $858,000. Mr. Clinton presented testimony in support of DTE's projected costs associated with its Charging Forward program.

Staff recommended that these projected capital expenditures be excluded from the projected test year rate base calculation. Mr. Welke explained that these proposed expenditures would not be eligible for the regulatory asset created, and further testified that as of September 19, 2019, DTE had spent none of the projected amounts corresponding to this line item.[463] On this basis, Staff recommended that the projected 2019 capital expense be reduced proportionally, by $618,000.[464] DTE did not object to this reduction to projected capital expense and this PDF finds it should be adopted.

B. <u>Working Capital</u>

Staff recommended a reduction of approximately $90.3 million to DTE's projected working capital balance of $1.462 billion, as shown in Exhibit S-2, Schedule B4, reflecting the calculations presented by Mr. Witt and the adjustments sponsored by Mr. Gerken. Not reflected in Staff's prefiled exhibits was an additional $4.2 million recommended by Mr. Welke to the Charging Forward regulatory asset. Mr. Coppola recommended a reduction of $74.3 million. ABATE recommended a reduction of $794.3 million to exclude DTE's pre-paid pension asset.

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[463] Staff witness Welke also recommended an adjustment to the Charging Forward regulatory asset, which is discussed as an element of working capital below, and to the test year amortization expense, which is discussed in the Adjusted Net Operating Income section of this PFD.
[464] See 9 Tr 3340.

1. **Staff and Attorney General Adjustments for Intercompany Accounts Balances**

Mr. Gerken recommended the exclusion of the Other Accounts Receivable-Associated Companies balance of $88.3 million. This amount included $68 million related to Reduced Emission Fuel (REF) companies under contracts that terminated in 2018.[465] He presented Exhibits S-9.0 and S-9.1 to show DTE's audit responses. Mr. Gerken's adjustment also included $20.3 million related to accounts receivable for services provided to other companies he testified were unrelated to DTE's core utility services.

Mr. Coppola also recommended the exclusion of $68 million in accounts receivable from the Reduced Emission Fuel (REF) companies, citing the same response to Staff discovery, and testifying that DTE's business dealings with these companies were discontinued in 2018. He likewise identified a $2 million transposition error DTE acknowledged in discovery. See 9 Tr 3008. His recommended adjustments are shown on Exhibit AG-1.15.

In her rebuttal testimony, Ms. Uzenski acknowledged that the REF receivable balance should be eliminated from working capital. She also agreed that the remainder of the other accounts receivable—associated companies balance should be excluded, but only if an offsetting amount of accounts payable-associated companies is also excluded. She testified: "The intercompany receivable is effectively financed by the inter-company accounts payable because affiliate balances are settled on a net basis."[466]

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[465] See 9 Tr 3239-2341

[466] See 6 Tr 1567.

In its brief, Staff acknowledges DTE's acquiescence in the $68 million REF-related adjustment. Staff takes issue, however, with Ms. Uzenski's assertion that accounts receivable for services provided to other companies unrelated to the utility's core business should be offset by accounts payable. Citing DTE's discovery responses in Exhibit S-18, Staff has revised its proposed reduction from $20.3 million to $11.3 million, agreeing that $9 million represents core utility business, but does not believe the accounts-payable offset is appropriate:

> As a general proposition, Staff and the Company agree that such an elimination from the Accounts Payable-Associated Companies is appropriate from an operational standpoint, absent ratemaking. (Exhibit S-18, STDE-20.3.) However, from a ratemaking standpoint, Staff disagrees that this treatment would be appropriate as non-utility items are routinely excluded from the derivation of customers rates. Generally, the Company agrees it would be inappropriate for its ratepayers to pay for, or finance, non-utility services through their rates. (Exhibit S-18, STDE-20.5.) Further, the $76,797,000 Accounts Payable-Associated Companies working capital test year balance was confirmed by DTE to arise from affiliate services incurred by DTE Electric to help maintain or augment the core services it provides to its ratepayers. (Exhibit S-9.0, p. 2.) Thus, DTE's qualified acceptance of Staff's adjustment posits the $20,271,408 Accounts Receivable-Associated Companies amount (including $11,271,408 of non-utility services) be financed by the $76,797,000 Accounts Payable-Associated Companies balance (solely a utility item). Staff maintains its disagreement with the Company's qualified acceptance as it would be inappropriate ratemaking to net utility and nonutility items to derive customer rates. (Exhibit S-18, STDE-20.6.) Therefore, Staff recommends the ALJ and the Commission adopt its adjustment to remove nonutility items from test year projected working capital in the amount of $11,271,408.[467]

This PFD finds that the REF-related reduction in working capital recommended by Staff and the Attorney General, and agreed to by DTE, is reasonable and should be adopted.

[467] See Staff brief, pages 8-9.

This PFD also finds Staff's recommended additional $11.3 million reduction to working capital reasonable and appropriate and recommends that it be adopted.

2. Balances for Cash and Materials & Supplies

Mr. Coppola proposed a $4.1 million reduction in working capital to reflect the average historical period balances rather than the year-end 2018 actual balances for cash and for materials and supplies. DTE did not address this in its rebuttal testimony or briefs. This PFD recommends that the adjustment be adopted.

3. Pension Asset

In Case No. U-20162, the Commission addressed an argument raised by ABATE that the prepaid pension asset should not be included in rate base. The Commission retained the pension asset in working capital, but called for further study:

> The Commission approves the prepaid pension asset for working capital treatment in this case. Prepaid pension assets are costs that have been incurred but have not been recovered from ratepayers and thus belong in working capital. ABATE provided no evidence to show that the company did not take this amount out of its own pocket to add to the pension fund – and the fund is ultimately the responsibility of ratepayers. However, in its next rate case, DTE Electric is directed to provide additional evidence on this cost demonstrating that the prepaid pension asset should be included in working capital, including the source of the funding of the prepaid pension asset.[468]

Mr. Cooper testified regarding DTE's pension obligations, discussing the components and presenting a calculation of projected test year pension expense. Ms. Uzenksi presented the following explanation as to why it is appropriate to include the prepaid pension asset in working capital:

[468] See May 2, 2019 order, page 48.

> The prepaid pension asset is a reasonable and prudent investment that is the result of the Company's policy of funding its pension trusts to minimize its pension costs. The Company has adopted a strategy of pension plan funding beyond the minimum funding requirements to realize the advantage of compounded returns on investments. This funding strategy reduces both current and long-term pension costs. Lower pension expense reduces rates for customers. In addition, the Company can deduct the contributions made to its pension trusts from its income taxes. These deductions increase the liability for deferred taxes. Increased deferred tax liabilities benefit customers because deferred taxes are a zero-cost component of the Company's weighted cost of capital. This reduces the overall rate of return used in setting customer rates. Also, when the expected return on pension assets is higher than the Company's cost of capital, customer rates are further reduced. The expected return is subject to change based on market conditions. Currently, the Company's authorized pre-tax rate of return is 6.81% compared to the expected return on pension assets of 7.3%. This provides a net reduction in rates for customers because pension expense reflected in rates includes the expected return.[469]

She acknowledged the Commission's directive in Case No. U-20162. She testified that the prepaid pension asset arises when DTE's annual contributions exceed the company's annual pension cost. She also presented Schedule B4.4 to show the growth of the prepaid pension asset from a $37.6 million liability in 2002 to a $757.7 million asset as of 2018. She testified that the accumulation of the prepaid pension asset was funded through investor capital:

> As the Company only recovers from customers through its rates the annual pension costs recognized pursuant to ASC 715-30 (f/k/a SFAS 87), any annual funding of the pension trust in excess of the annual pension costs must be from investor capital. Since the prepaid pension asset represents the cumulative difference between the annual pension costs and annual Company contributions to the pension trust, the prepaid pension asset could only be from investor capital.[470]

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[469] See 6 Tr 1541-1542.
[470] See 7 Tr 1543.

She also testified that the pension assets are $811.3 million less than the pension liability, and thus the pension trust is not overfunded.

ABATE recommends that the amount by which DTE's pension obligation is prepaid should be excluded from working capital. Ms. Alderson disputed that DTE complied with the Commission's instructions.[471] Ms. Alderson testified that DTE has included $794 million in working capital to reflect the difference between the total value of its pension fund and its total pension obligations, which is half the size of its total working capital balance. Citing Schedule B4.4 of Exhibit A-12, Ms. Alderson testified that at the beginning of 2003, DTE's net pension liability was $37.6 million, which through market returns on the fund itself, the amortization of losses, and contributions by ratepayers and shareholders, DTE had a net prepaid pension asset of $105.7 million by the end of 2003, which has steadily increased at an average growth rate of 14% through 2018.[472] She testified that the full amount of the asset was not funded by investor capital and thus it is unreasonable to provide DTE a full return on the asset amount. She also contended that DTE has not established that any additional shareholder contributions to the prepaid pension asset were reasonable and prudent.[473] She expressed a concern that by including the prepared pension asset in rate base, DTE is motivated to increase the value of the asset with larger discretionary funding amounts. She presented Table 1 at 7 Tr 1807 to show that the average annual pension asset growth rate of 14% is significantly greater than the 5.8% average annual growth rate in rate base generally.

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[471] See 7 Tr 1810-1811.
[472] See 7 Tr 1805-1806.
[473] See 7 Tr 1806, 1811.

As of the time she filed her testimony, she stated, ABATE had asked DTE for information regarding the cumulative actual return on plan assets over the same time period, but had not yet received it. In the absence of such information, she used as a proxy the historical expected return on assets, calculating an expected return of $3.328 billion between 2003 and the projected test year, with the projected test year return equaling $235.8 million.[474] In Ms. Alderson's opinion, because these amounts were not contributed by either ratepayer or investor funding, it is unreasonable for DTE to a return on these amounts, which she equated to a return on the original investment. Ms. Alderson acknowledged that annual pension expense is reduced to reflect the expected return on total pension assets. She further testified that the magnitude of the pension asset is increased by accounting regulations that allow DTE to defer certain reductions in expected plan assets and certain increases in expected plan liabilities over the remaining service life of the employees covered by the plan. Ms. Alderson also testified that it is not possible to determine the exact amount contributed by ratepayers since DTE's rates were not reset every year and because the projected test year pension expenses included each time rates were reset would have differed from the actual. She thus disputed Ms. Uzenski's testimony that the full amount of the $794.3 million prepaid pension asset is investor funded. She recommended that the prepaid pension funding be removed from working capital.[475]

[474] See 7 Tr 1807-1808.
[475] See 7 Tr 1811-1812.

DTE objects to ABATE's recommendation. In rebuttal, Ms. Uzenski reiterated her direct testimony that customers have not paid for the pension asset. See 6 Tr 1568. She also testified that pension expense is not based on the actual return on assets, but on the expected return on assets.[476] Answering the question "[h]ow much of the prepaid pension asset was funded by DTE Electric customers," Ms. Uzenski testified that a conservative estimate would be that ratepayers only covered the cumulative expenses to date, $2,073.2 million as presented in Schedule EE3 of Exhibit A-40, and cited Mr. Cooper's testimony that in its filing in this case, DTE understated its expected pension expense for the test year:

> Underlying the projected ending balance of $838.7 million at April 30, 2021, is cumulative expense of $2,073.2 million. The cumulative expense of $2,073.2 million is likely a conservative best estimate of the amount of customer funding since December 31, 2002 for several reasons. First, other than during the period the Pension Equalization Mechanism was in effect (2002 through 2008), the Company's rates have not been adjusted every year to correspond with the Company's actual pension expense. So, there is an inevitable mismatch in the Company's recorded pension expense with the pension expense collected from customers. Second, a portion of pension expense is capitalized and therefore subject to recovery as the plant is depreciated. Third, variances between the amount assumed in rates and the actual amounts collected have occurred due to factors such as weather-driven sales volumes. In spite of these factors, for the sake of simplifying the issue, I am willing to assume that the Company's recorded pension expense is still a reasonable estimate of the pension expense collected from customers.
>
> However, Ms. Alderson's concern about variances between booked expense and the amount assumed in rates does have some merit in connection with projected pension expense in this case, given the current volatility in the financial markets. For example, as discussed by Company Witness Cooper, the Company's updated pension projections that reflect a reduction in the discount rate and an increase in the 2019 expected return

[476] See 6 Tr 1549.

> on assets, result in an increase to pension expense of $12.0 million compared to the Company's original filing.[477]

She then recommended a pension expense tracker to defer as a regulatory asset or liability any difference in the company's actual net pension expense in future years, citing the treatment of Other Post-Employment Benefit (OPEB) Expense adopted in Case No. U-17767. DTE's brief largely repeats Ms. Uzenski's testimony.

In its initial brief, responding to Ms. Uzenski's rebuttal testimony, ABATE disputed Ms. Uzenski's claim that all funding of amounts greater than annual pension expense should be considered the contributions of DTE investors, citing Ms. Alderson's lengthy explanation of sources of funding including ratepayers, returns on the fund assets, and delayed accounting of losses on the fund balance. ABATE also argues that DTE did not establish that any discretionary excess contributions it made to the pension fund were reasonable and prudent. Additionally, ABATE objects to creating a regulatory asset as Ms. Uzenksi suggested in her rebuttal testimony.

This PFD concludes that ABATE's recommendation should be adopted. The Commission provided DTE with the opportunity to demonstrate that the entirety of the prepaid pension asset was supplied by investors rather than ratepayer funding. DTE made no effort whatsoever to comply. Instead, Ms. Uzenksi relied on a series of assumptions that she provided no support for. That is, she asserted DTE made contributions above required levels as a policy, but she provided no documentation. She

[477] See 6 Tr 1569-1570.

asserted that "at best" ratepayers paid the annual pension expense obligation and no more, but she provided no analysis and no documentation.

This PFD starts from the premise that virtually all revenues the utility receives are supplied by ratepayers. Ms. Uzenski identified at least two line items of ratepayer pension plan funding: the pension expense included as a line item in other O&M, and depreciation expense, included as a separate line item, through which ratepayers pay for pension costs that are capitalized along with labor expenses associated with capital projects. DTE has an obligation to its ratepayers and to its employees to ensure that it credits its pension plan with all ratepayer-supplied funding for the pension plan. Thus, it is clearly not "reasonable" to assume as Ms. Uzenski does that ratepayers never paid more than the minimum required funding amount DTE was required to contribute. Similar to the situation with the capitalized incentive compensation expenses discussed above, although in this case DTE actually has adjusted its projected pension expense included in O&M to reflect amounts recovered through capitalization, it is not possible on this record to determine how much duplicative capitalization may have occurred over the last decades.

Additionally, DTE's annual pension expense includes an amortization amount that reflects significant differences between actual plan experience and DTE's actuarial assumptions. Because DTE can amortize these differences over the expected service life of the plan participants, the amortization amount in DTE's pension expense calculation is assigned to ratepayers. DTE did not present any detail on the underlying actuarial errors reflected in that cost element, although Ms. Uzenski suggests it has to do with the difference between actual and assumed interest rates on plan assets, it may encompass a wide variety of differences. DTE has also not stated the full unamortized amount. DTE is thus asking ratepayers to pay interest on the portion of the pension accounting that shows an “asset,” while also asking ratepayers to pay the amortization amount of what is really an offsetting liability.

DTE has failed to establish that it is appropriate to keep the prefunded pension asset in working capital and this PFD recommends that it be removed.

This PFD finds no reason to adopt DTE’s later request for a pension expense tracker. DTE requests a regulatory asset for any difference between DTE’s actual net pension expense and $50.7 million projected.[478] This PFD recommends DTE’s request be denied. As noted above, DTE did not attempt to address prior levels of ratepayer funding of the pension plan. Because of this, it has failed to identify a factual predicate for its request. DTE does not even acknowledge in its request the significant potential for those costs to be capitalized, which is not accounted for in its tracker proposal.[479] In addition, it sought this relief late in the proceeding, giving rise to objections by both ABATE and Staff. Indeed, Staff argues strongly against adoption of a tracker:

> 18 days is insufficient for a thorough review. In Case No. U-16489, a case specifically regarding the pension accounting mechanism, the Company similarly proposed to defer the differences in pension expenses. Specifically, the Company “propose[d] to defer the difference between 2011 and 2012 actual pension and OPEB expense, compared to the expense levels reflected in current base rates to account 182.3, Other Regulatory Assets, effective January 1, 2011 and January 1, 2012, respectively. The Company estimate[d] this difference to be approximately $60 million for 2011 and $45 million for 2012, based on studies provided by the Company’s actuaries, Hewitt Associates, LLC.” Case No. U-16489, Company Application, bullet point 4. Case No. U-16489 was subsequently combined

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[478] See DTE brief, page 153, 6 Tr 1570.
[479] See Cooper, 5 Tr 897-898.

with Case No. U-16472, DTE's general rate case, which was filed 3 days later. Staff's audit of that proposed deferral took 3 months, from October 29, 2010 to February 3, 2011. That audit found that the Company had 11 actuary reports compiled over the previous year (2010), that two of the reports dated 50 days apart forecasted pension and OPEB expense for 2012 that differed by $76 million, and that the Company forecasted its pension and OPEB expense using different assumptions for "Rate Case Purposes" vs. "Financial Forecast Purposes." See Case No. U-16472/U-16489, 13 TR 2266-67. Because the actuarial reports were unreliable to project 2012 expenses and the most recent 2010 actuarial reports (as well as some 2012 projected) pension and OPEB amounts were "lower than the amount included in Detroit Edison's current rates…," the Commission denied the Company's deferral request. Case Nos. U-16472/U-16489 Commission Order Dated October 20, 2011, pp 57-58). The Commission and ALJ, as recommended by the Staff, instead relied on prior actual 2011 expenses, as stated in the December 17, 2010 report, for the test year ending March 2012, and did not defer the test year expenses, since there was nothing to defer.

Because it took three months to thoroughly review a similar proposal in a prior case, it is difficult at best for the same thorough review within the 18-day paradigm allowed here. Staff believes the Commission is left with insufficient testimony and scant supporting evidence with which to make its determination. Therefore, Staff recommends that the proposed pension tracker be denied at this time.[480]

4. Charging Forward Regulatory Asset

As shown in Schedule B4.1, line 45, DTE has included $4.3 million as a regulatory asset for the Charging Forward program in its projected test year working capital. The calculation of this amount is shown in Schedule B4.2, as the average of the projected April 2020 balance of $2.9 million and the projected April 2021 balance of $5.8 million. Mr. Uzenski testified that the projected balance at the end of the test year April 2021 reflects $6.5 million of deferred expense less $0.8 million cumulative amortization.

[480] See Staff reply brief, pages 39-40.

In addition to his recommendation as discussed above, Mr. Welke recommended an adjustment to the Charging Forward regulatory asset. After explaining that the regulatory asset and amortization authorized by the Commission in Case No. U-20162, Mr. Welke testified:

> The Company projects a regulatory asset of $4,349,000 related to its Charging Forward Program. Because that asset does not meet the Commission's criteria for recovery described above, Staff recommends that the Commission not approve its inclusion in this case. (Exh. S-3, Sch. C5.3, ln 8). Alternatively, Staff recommends that a regulatory asset be approved for $161,000, which relates to the expenses actually incurred and reviewed. (Exh. S-3, Sch. C5.3, ln 12). Staff recommends that the Company request a prudence review of incremental actual spend for its inclusion in rates in a subsequent rate case.[481]

Although not included in the revenue deficiency calculations in Exhibit S-1, as explained by Mr. Welke,[482] in its initial brief, Staff argues that projected but not yet incurred costs are not appropriately given regulatory asset treatment in this case, and recommends a $4.2 million reduction in working capital.[483] That is, Staff recommends that the Commission adopt Mr. Welke's alternative recommendation to include as a regulatory asset the 2019 expenses of $220,000 that have been reviewed and approved, with a five-year amortization amount of that expense of $40,000 as component of O&M expenses.

In her rebuttal testimony, Ms. Uzenski objected to this element of Staff's charging forward adjustment:

> I understand that amortization of the regulatory asset for rate-making purposes can include only those amounts audited by Staff per the Commission's Order in Case No. U-20162. However, depending on the timing of future rate cases and Staff's reviews, some costs will not be recovered at all because the Company is required to start amortization

[481] See 9 Tr 3340.
[482] See 9 Tr 3341.
[483] See Staff brief, page 9.

> expense for accounting purposes the year after the costs are incurred. The unamortized balance should be included in working capital to slightly mitigate the loss from amortization expense that is above the amount in rates. While this would not provide full recovery of the deferred costs, it would at least provide a return on the unamortized balance. Otherwise, Staff's approach is not simply denying current recovery of legitimate costs "until they have undergone a future reasonableness and prudence review in a rate case"; it results in a permanent loss of a return on the unaudited amounts.

DTE relies on Ms. Uzenski's rebuttal testimony in its brief and reply.[484] This PFD finds that neither Staff nor the Commission set up the deferral and amortization accounting under the expectation that DTE would begin amortizing deferred amounts before they are reviewed. In its brief, Staff agrees that DTE should be compensated for the unamortized balance once it is reviewed. This PFD finds Staff's reduction to the projected test year working capital regulatory asset for the charging forward program is reasonable, consistent with the Commission's order in Case No. U-20162, and does not result in DTE amortizing costs greater than the level included in rates.

C. <u>Rate Base Summary</u>

Based on the recommendations above, this PFD recommends a projected rate base of approximately $17.1 billion, as shown in more detail in Appendix B attached.

VI.

<u>COST OF CAPITAL</u>

The rate of return component of the revenue requirements determination is designed to meet the constitutional and statutory standards entitling the utility to a fair rate of return on its investment. The Commission in its past decisions and the witnesses

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[484] See DTE brief, pages 87-89; DTE reply, pages 54-55.

testifying in this case recognize as controlling precedent the U.S. Supreme Court cases *Bluefield Water Works Co v Public Service Comm of West Virginia*, 262 US 679; 42 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).

To determine the rate of return to use in setting rates, it is customary to start with the development of an appropriate capital structure, and then to evaluate the appropriate costs to assign each element of the capital structure. The appropriate capital structure is discussed in subsection A below, the cost of debt is discussed in subsection B, and the cost of equity capital is discussed in subsection C. The overall rate of return recommendation is presented in subsection D.

A. <u>Capital Structure</u>

The capital structure used for ratemaking includes as its components long-term debt, preferred stock, and common equity capital, along with short-term debt and other items such as deferred taxes that reflect sources of financing available to the company. Only long-term debt, preferred stock, and common equity capital are considered part of the utility's "permanent" capital, and it is common for capital structures to be shown in exhibits on both a "permanent" basis and on a ratemaking basis. DTE does not have preferred stock so discussions of its permanent capital structure refer only to long-term debt and equity ratios.

There is no dispute among the parties that the Commission should use a permanent capital structure with 50% equity and 50% long-term debt,[485] there are two disputes involving the ratemaking capital structure.

1. Short-Term Debt Balances

The Attorney General argues that the short-term debt balances in the ratemaking capital structure should be increased from $220 million to $337 million. Mr. Coppola presented historical data on page 2 of his Exhibit AG-1.16 to show that the company has used progressively greater amounts of short-term debt over the last three years. He also noted that DTE has increased the size of its short-term debt credit facilities at an increased cost of approximately $160,000.[486] He testified that including the historical level of short-term debt would decrease DTE's projected revenue requirement by $7 million.[487]

In his rebuttal testimony, Mr. Solomon testified that the $220 million short-term debt balance included in the company's ratemaking capital structure "is a reasonable average amount of outstanding short-term debt for the company." He acknowledged the increased short-term credit arrangements, but asserted: "The Company needs to be in a position to fund any large expenditures or cash draws that may occur and have ample unused liquidity for any unforeseen or unexpected cash needs. The level of short-term debt projected by the Company provides that ample liquidity."[488]

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[485] Mr. Solomon testified that DTE is using the 50-50 capital structure to reduce disputed issues in this case, although it believes a more appropriate capital structure would contain 49% debt and 51% equity. See 6 Tr 1456.
[486] See 9 Tr 3010-3011.
[487] See 9 Tr 3011.
[488] See 6 Tr 1467.

In her brief, highlighting the annual increases shown on page 2 of Exhibit AG-1.16, the Attorney General argues that it makes sense that DTE would rely on increasing amounts of short-term debt as it grows its business, justifying use of the most recent historical level.[489] DTE relies on Mr. Solomon's testimony as quoted above, emphasizing that its proposed level of short-term debt provides "ample liquidity."[490]

Primarily for the reasons explained in the discussion of DTE's distribution system capital expenditures, above, this PFD concludes that it is reasonable for DTE to have a level of short-term debt to provide liquidity when confronted with unexpected or greater-than-projected expenditures. Actual utilization should not be the sole determining factor in the amount of short-term debt DTE is projected to draw on to finance its test year operations. Nonetheless, the Commission should expect DTE to use this line of credit rather than deferring expenses that its own witnesses represented to this Commission are "necessary" or "needed."

2. Accumulated Deferred Income Tax Balances (ABATE's Regulatory Plan)

The company's Accumulated Deferred Income Tax (ADIT) balances are also included in the ratemaking capital structure. Ms. Uzenski included the balances in Exhibit A-12, schedule B4.2 but deferred to Ms. Wisniewski for support:

> The Tax Reform Regulatory Liability on line 95 results from the Tax Cuts and Jobs 20 Act of 2017, which among other things, lowered the corporate Federal tax rate from 35% to 21%. The reduction in the tax rate required that all existing deferred tax balances be re-measured using the 21% rate. The reduction in deferred taxes was recorded to a regulatory liability to be refunded, generally, over the life of the items causing the deferred tax,

[489] See Attorney General brief, pages 91-92.
[490] See DTE brief, pages 95-96; also see DTE reply, page 57.

> primarily plant. Witness Wisniewski explains the calculation of the regulatory liability and the Company's refund schedule.[491]

Ms. Wisniewski did not provide detail in her testimony, but did assert that DTE incorporated the same methodology for amortizing its deferred tax balances as the Commission approved in Case No. U-20162.[492]

ABATE argues that the reduction of excess ADIT should be accelerated as an offset to expenses as explained in Mr. Walters's testimony. Mr. Walters testified that he recommends a revised version of the plan ABATE presented in DTE's last rate case to offset the increased depreciation expense associated with the accelerated retirement of Belle River with an accelerated amortization of excess unprotected ADIT balances. He cited the Commission's direction to the parties in Case No. U-20162 to explore this further in DTE's next rate case, and noted that DTE did not address this issue in its rate case filing.[493] He explained that IRS rules do not govern excess unprotected balances, and cited a Utah case in which Rocky Mountain Power and the parties to its recent rate case agreed to use unprotected balances to offset the depreciation of a thermal generation plant.[494] Citing DTE's discovery response in Exhibit AB-27 identifying the incremental depreciation cost associated with the early retirement of Belle River as $34.2 million per year, Mr. Walters testified:

> This is a tremendous single issue cost increase to DTE's ratepayers. I am proposing to accelerate the amortization periods for DTE's unprotected excess ADIT balances. Specifically, I recommend the 23 year amortization period for plant-related unprotected excess ADIT be reduced to 13 years, and the 14 year amortization period for non-plant unprotected excess ADIT

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[491] See 6 Tr 1551.
[492] See 9 Tr 3574-3575.
[493] See 7 Tr 1891.
[494] See 7 Tr 1893.

> be reduced to 9 years. On a revenue requirement basis, not accounting for the small offset produced through reduced zero-cost capital, these adjustments will reduce the Company's claimed revenue deficiency by $34.8 million, fully offsetting the increase in depreciation expense for Belle River of $34.2 million.[495]

He testified that as a result of this change, the revenue requirement would increase an additional $2.4 million per year, assuming the reduced deferred tax balances are replaced with 50% each debt and equity, which would lead to a net reduction in the test year revenue requirement of $32.4 million. He also presented a Net Present Value Revenue Requirement (NPVRR) analysis in Exhibit A-28, page 3, which he testified shows that the net present value of the revenue requirement reduction under his recommended schedule is a reduction of $263 million, while the more gradual approach results in a net present value revenue reduction of $106 million: "In other words, under my proposal, customers are better off by approximately $129.8 million through 2030. This benefit is net of the incremental annually increasing offset in revenue requirement as a result of a lower zero-cost capital balance, which is accounted for on line 3 of this Exhibit."[496]

In his rebuttal testimony, Mr. Solomon disagreed, contending that accelerated return of the excess ADIT balances could hurt the company's financial metrics:

> The cash loss would have a 1.0:1.0 impact to the Company's Funds from Operations that is the numerator in our FFO to debt calculation, which is a key financial metric with the agencies. Long-term debt will also increase as the Company funds the cash loss with a mix of debt and equity. The incremental proforma impact of S&P's FFO to debt calculation will be a reduction of ~0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the financial integrity of the Company. The accelerated ADIT as proposed under Witness Walter's Regulatory Plan will also have a negative longer-term impact to customers. Accelerating the

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[495] See 7 Tr 1893.
[496] See 7 Tr 1897.

> ADIT has the impact of replacing deferred taxes which have a zero-funding cost in the Company's capital structure with debt and equity. Plus, the impact would grow each year as debt balances grow with only a partial offset for earnings on equity. The lower rates customers would experience in the early years would be offset by higher costs after ten years. This impact could be exacerbated if the Company experiences higher interest costs due to lower credit ratings.[497]

Ms. Suchta presented DTE's projected rate of return summary in Schedule D1 of Exhibit A-14. Ms. Suchta also testified in rebuttal on this topic, addressing Mr. Walters's net present value analysis.[498] She took issue with the time period of this analysis, contending that he did not capture all impacts of the two scenarios being compared:

> Specifically, Witness Walters ended his analysis in 2030 because that is the year Belle River is scheduled to be retired. By ending the analysis at 2030, ABATE Witness Walters' analysis ignores the amortization of the excess ADIT amortization beyond 2030. By extending the NPV analysis to 2042, the analysis will correctly include the full amortization of the excess ADIT under both scenarios.[499]

Ms. Suchta presented a revised analysis in her Exhibit A-42, which extends the period of study through 2042, with two additional changes to reflect full amortization of the unprotected non-plant ADIT over the 9-year period ABATE proposes, and to reduce the rate of return once the non-plant balance is fully amortized in 2028. She testified that the resulting analysis, customers would be better off by approximately $41 million under DTE's proposed amortization schedule than under ABATE's proposed amortization schedule.[500]

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[497] See 6 Tr 1467-1468.
[498] See 9 Tr 3422-3424.
[499] See 9 Tr 3423.
[500] See 9 Tr 3427.

In their briefs, the parties primarily track the statements made by their witnesses. Recognizing that the Commission addressed this issue less than a year ago in DTE's last rate case, this PFD thus finds that the record in this case does not support an accelerated return of the excess unprotected ADIT balances, although ABATE should be free to seek accelerated return of the excess unprotected ADIT balances in a future rate case. Given the complexities of the analysis, ABATE has not established that ratepayers are better off under its proposal, and that uncertainty argues in favor of the status quo.

Also related to the ADIT balances, Staff and the Attorney General also recommend that DTE follow reporting requirements regarding its actual excess deferred tax balances. These reporting obligations are discussed further below.

B. <u>Cost of Debt</u>

In its filing, DTE projected the cost of long-term debt to be 4.31%, and the cost of short-term debt to be 3.25%.

Mr. Solomon testified that DTE projected the cost of long-term debt as shown in Schedule D2 of Exhibit A-14, using actual costs for debt outstanding as of December 31, 2018, with known or projected costs for future debt issuances and redemptions from February 2019 through February 2021, as also shown in a chart in his testimony at 6 Tr 1460. He testified that the projected interest rates for debt issuances are based on Bloomberg forecasts of long-term borrowing rates for A-rated utilities, ranging from 4.21% to 4.25% as shown. He also explained that the "net proceeds" method used to calculate the cost of long-term debt, reflecting underwriters' compensation and other expenses as a reduction to the proceeds.[501]

Mr. Solomon explained that the short-term debt cost projection reflects the interest rate on short-term borrowings and the facility fees DTE pays under its credit agreement. He determined the interest rate by adding 25 basis points to the May 2019 Bloomberg forecast of the one-month LIBOR rate for the test year (2.57%). He also testified that DTE has committed to pay $.95 million for its $500 million credit agreement, as discussed above.[502]

Staff witness Mr. Ufolla presented Staff's recommended debt costs, with a rate of 4.22% for long-term debt and a rate of 2.73% for short-term debt as shown in Schedules D2 and D3 of Exhibit S-4 and in Chart 2 of his testimony at 9 Tr 3319. He explained that rather than rely on the Bloomberg projection for long-term debt costs, Staff used 30-year Treasury yield projections of 2.54% and 3.13% for 2020 and 2021, plus 100 basis points to reflect the approximate risk premium DTE paid in recent issuances. He testified that interest rates could be even lower, based on expectations that the Federal Open Market Committee would cut rates for a third time at its October meeting. For short-term debt costs, Mr. Ufolla used a more recent LIBOR projection than DTE, and used the higher 3-month projection rather than the 1-month projection.[503]

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[501] See 6 Tr 1461.
[502] See 6 Tr 1461-1462.
[503] See 9 Tr 3321.

In his rebuttal testimony, Mr. Solomon objected to reliance on updated interest rate forecasts for long-term and short-term debt, asserting that the projected values are constantly changing, and citing more recent 30-year Treasury rates as follows:

> The Company supplied it's forecasted long-term debt interest rates based on data from May of 2019. The Staff interest rates were determined based on data from September 2019.The 30-year treasury rate as of May 1, 2019 was 2.94% and by September 2, 2019 it was 1.95% or a decline of about 1.0%. By November 15, 2019 it was 2.31%, up 0.36%. Witness Ufolla stated that interest rates may be even lower than Staff is projecting noting that the Federal Open Market Committee ("FOMC") cut rates by 25 basis points in September and another cut was expected in October of 2019. The FOMC did cut rates by 25 basis points in September and October of 2019, but the 30-year Treasury rate as of November 15, 2019 was 2.31% or 0.36% higher than on September 1, 2019.[504]

Contrary to Mr. Solomon's preference, it is common in rate cases for Staff to update the debt costs and for the Commission to rely on the updated figures. While interest rates fluctuate, there is no suggestion here that Mr. Ufolla cherry-picked an aberrant or unreflective date on which the interest rates were particularly low, and indeed, his testimony reflects his considered opinion that interest rates would continue to be lower than DTE's projection. The interest rates cited by Mr. Solomon in his rebuttal testimony, not incorporated into a revised projection, are nonetheless lower than the interest rates underlying the company's filing. Thus, this PDF concludes that the updated debt costs projected by Staff should be adopted in this case.

C. <u>Cost of Equity</u>

As discussed below, four of the witnesses testifying on the appropriate rate of return on equity for DTE employed a variety of models using groups of proxy companies

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[504] See 6 Tr 1466.

chosen to be comparable to DTE resulting in a range of estimates of the cost of equity capital. The analysts make their final recommendations by reviewing the range of costs produced by the models along with other information including rates of return authorized by other state commissions and the analysts' views of the relative riskiness of DTE in comparison to the proxy companies. In the discussion that follows, the analysis and recommendations of DTE, Staff, the Attorney General, and ABATE are reviewed beginning with a discussion of the proxy companies selected by each of the four analysts using a proxy group (section 1), then reviewing the models used by those analysts (sections 2 through 5), then information on rates of return set by other commissions (section 6), and the general discussion of risk incorporated in the analysts' recommendations (section 7). This PFD's recommendation is provided in section 8.

With the increased frequency of rate cases in recent years, the Commission has provided guidance regarding changes to the authorized return on equity. In its March 29, 2018 order addressing a Consumers Energy electric rate application in Case No. U-18322, the Commission stated:

> [T]he Commission appreciates the amount of time and effort the parties put into developing their positions on ROE, providing the Commission with thoughtful analyses upon which to make the most informed decision possible. On the other hand, making a technically correct and holistic decision becomes difficult when too many methodologies are included in the record, especially if they contain concepts that are novel or untested. Accordingly, the Commission agrees with the ALJ that in future rate cases the company should focus more on objective arguments rather than making sensational statements to bolster its position. The Commission also asks other parties to consider the degree of financial adjustment they are requesting the Commission to undertake in one proceeding, because it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions. In the future, narrowing the arguments and recommended ROE ranges would greatly assist the Commission in

> charting a reasonable and steady path on this important issue that impacts the company, its customers, and its shareholders.[505]

In Case No. U-18255, less than one month after issuing the above-quoted order in Case No. U-18322, the Commission rejected DTE's request for an authorized return on equity of 10.5%, explaining:

> The Commission finds that an ROE of 10.00% most appropriately compensates DTE Electric for the regional economic and company-specific aspects of risk, while maintaining its ability to attract capital, and ensuring the continued vitality of the company. It also strikes a balance between the company's interest in investment and the interests of DTE Electric's ratepayers in safe, reliable, and affordable energy. The Commission agrees with the PFD that little weight should be given to the utility's ATWACC calculations. 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:
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>> 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.
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> 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.

[505] See March 29, 2018 order, pages 43-44.

> 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.[506]

In its May 2, 2019 order in Case No. U-20162, approximately 10 months ago, the Commission addressed the appropriate return on equity for DTE.

> The Commission finds that preserving an ROE of 10.00% most appropriately compensates DTE Electric for the regional economic and company-specific aspects of risk, while maintaining its ability to attract capital, and ensuring the continued vitality of the company. It also strikes a balance between the company's interest in investment and the interests of DTE Electric's ratepayers in safe, reliable, and affordable energy. The Commission, in reaching its determination, also takes into consideration the company's unique circumstances and characteristics, rising interest rates, and the standards set forth in *Bluefield* 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.
>
> By maintaining DTE Electric's ROE of 10.00%, the Commission believes there is an opportunity for the company to earn a fair return during these 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

[506] See April 18, 2018 order, Case No. U-18255, pages 32-33.

> important to consider how extreme market reactions to singular events, as have 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.[507]

In the discussion that follows, the recommendations of each of the witnesses are discussed in section 1, followed by a review of the testimony addressing disputed issues in section 2, with this PFD's findings in section 3.

1. Analyst Recommendations

As preface to a review of the recommendations of each of the witnesses testifying on the cost of capital, it should be noted that each of the analysts performing financial modeling discuss and rely on the standards established in *Hope* and *Bluefield*, cited above.

a. DTE

DTE requests an authorized return on equity of 10.5%, from a range of 9.75% to 10.75%., based on Dr. Villadsen's testimony. In her analysis, Dr. Villadsen created two proxy groups, one consisting of companies with at least 50% of their revenues from regulated electric utilities, and another consisting of companies with a least 50% of their revenues from regulated natural gas or water companies, which she labeled the "other highly regulated utility" (OHRU) proxy group. She explained her choice of proxy companies at 6 Tr 1238-1246, with the resulting 26 electric utilities in Figure 13 at 6 Tr

[507] See May 2, 2019 order, pages 67-68.

1242, and 11 gas and water companies in Figure 14 at 6 Tr 1244. [508] Dr. Villadsen applied what she characterized as standard cost of capital estimation models, including two versions of the Capital Asset Pricing Model (CAPM) and two versions of a discounted cash flow model. She also performed what she labeled as an implied risk premium analysis.

Dr. Villadsen described her CAPM analyses at 6 Tr 1246-1256. She used two sets of inputs, and Value-line adjusted betas in the standard CAPM formula. For her first set of inputs, “scenario 1”, she used a risk-free rate of 3.75 %, which she constructed from the March 2019 Blue Chip Economic Indicators forecast of 3.0% for the 2020 10-year Treasury bond yield, plus 0.50% as her estimate of the historical maturity premium of 20-year Treasury bonds relative to 10-year Treasury bonds, plus an additional 0.25% to reflect approximately half of what she views as the currently-elevated level of utility bond yields to Treasury rates compared to historic levels.[509] For the market risk premium input in her scenario 1, she used the historical average market risk premium of 6.91% based on data from 1926 to 2018.[510] The results of her CAPM analysis using the scenario 1 inputs for all of the proxy companies are presented on page 1 of Schedule D5.10 of Exhibit A-14. For her “scenario 2” inputs, she used a risk-free rate of 3.5%, calculated as described above but without the additional 0.25% adjustment to reflect elevated risk-premiums, and she used a market risk premium of 7.91%, with the 100 basis point

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[508] The proxy companies are also listed in Schedule D5.2 of Exhibit A-14, with additional financial information about each company in Schedule D5.3
[509] See 6 Tr 1248.
[510] See 6 Tr 1249.

increase over the historical 6.91% value to reflect what she considers evidence that the current market risk premium is higher than the historical value.

> The 7.91 percent MRP was chosen by looking to forecasted MRP and the increase in yield spread discussed above. Specifically, Bloomberg's forward-looking market implied MRP is currently estimated at approximately 6.84 percent (when expressed relative to 20-year bond yields) and was above the 6.91 percent long-term historical average value in most months of 2018. At the same time, I recently estimated a MRP of 10.77 percent using the methodology in FERC's NETO Briefing Order.
>
> Lastly, the increase in yield spread can be used to provide a quantitative benchmark for the implied increase in MRP based on a paper by Edwin J. Elton, et al., which documents that the yield spread on corporate bonds is normally a combination of a default premium, a tax premium, and a systematic risk premium. Of these components, it is the systematic risk premium that likely explains the vast majority of the yield spread increase. In other words, unless the risk-free rate is underestimated as described above, the market equity risk premium has increased relative to its "normal" level.[511]

Her CAPM analysis using the scenario 2 inputs for the proxy companies are presented on page 2 of Schedule D5.10 of Exhibit A-14.

Dr. Villadsen also performed a version of the CAPM analysis referred to as the Empirical Capital Asset Pricing Model (ECAPM), which she testified is based on empirical evidence that the CAPM underestimates the cost of capital for low-beta stocks. Technically, the ECAPM model adds the variable alpha as an increase in intercept and a reduction in the slope of the "security market line" reflecting the relationship between betas and returns. She chose an alpha of 1.5%, citing technical material in her Appendix B to support the magnitude of her alpha value.[512] As with her CAPM analysis, she applied

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[511] See 6 Tr 1249-1250.
[512] See 6 Tr 1254.

the ECAPM to the proxy groups using Value Line betas, and the sets of inputs in her scenarios 1 and 2. Her ECAPM analysis for each scenario for each of the proxy companies are presented on pages 1 and 2 of Schedule D5.10 of Exhibit A-14.

For her DCF modeling, Dr. Villadsen used both a single-stage and a multi-stage version. For growth rates for the single-stage model and for the first stage of the multi-stage version, she relied on analyst forecasts of earnings growth from Value Line and Thompson Reuters IBES.[513] For the multi-stage version, she assumed that after five years, growth would taper over another five years to the 4% projected long-term GDP growth rate from Blue chip Economic Indicators. The results of her DCF modeling are presented in Schedule D5.6 of Exhibit A-14 for each of the proxy companies. Although not discussed in her testimony, the dividend yields she used are also included in that schedule.

For her risk premium analysis, Dr. Villadsen derived a quarterly risk premium from the average rate of return on equity authorized by state regulatory agencies over the time period 1990 through the first quarter of 2019, relative to the average 20-year Treasury bond yield in each quarter. She used linear regression to model the risk premium as a linear function of the 20-year Treasury bond yield. Testifying that the regression showed the linear function was statistically a good fit with an r-squared of over 80%, she used the regression slope and intercept values to estimate the risk premium associated with the

[513] See 6 Tr 1258.

risk-free rates used in her scenarios 1 and 2, i.e. 3.5% and 3.75%, with the resulting returns estimated as 10.25 and 10.3%.[514]

Throughout Dr. Villadsen's testimony are repeated discussions of financial leverage and her opinion that the range of returns on equity appropriate for DTE should be estimated such that the overall after-tax weighted average cost of capital using DTE's book value capital structure is the same as the proxy companies. Thus, once she chose the inputs for each model and applied them to the proxy companies, she performed a second set of calculations to adjust the resulting returns.[515] The overall weighted after-tax cost of capital for her proxy companies using the equity costs from her CAPM and ECAPM analyses, scenarios 1 and 2, are calculated in results her Schedule D.11 of Exhibit A-14, and the application of the proxy group averages are applied to DTE's book value capital structure in her Schedule D.12 of Exhibit A-14 and also included in the summary chart in Figure 17 at 6 Tr 1255. The overall weighted after-tax cost of capital using each of her two sets of DCF equity cost results is calculated for each of the proxy companies in her Schedule D5.7, with the proxy group averages applied to DTE's book value capital structure in her Schedule D5.8 and also summarized in Figure 18 of her testimony at 6 Tr 1259.

For her CAPM analyses, also to reflect financial leverage, she also performed another version of both the standard CAPM and the ECAPM using further-adjusted betas to reflect additional risk associated with debt:

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[514] See 6 Tr 1262.
[515] See 6 Tr 1214-1216.

> A second approach was developed by Professor Hamada, who estimated the cost of equity using the CAPM and made comparisons between companies with different capital structure using beta. Specifically, in the Hamada approach, I use the estimated beta to calculate what beta would be associated with a 100 percent equity financed firm to obtain a so-called all-equity or assets beta and then re-lever the beta to determine the beta associated with the regulatory capital structure. This requires an estimate of the systematic risk associated with debt (i.e., the debt beta), which is usually quite small. In Appendix B, I set forth additional technical details regarding the methods that can be used to account for financial risk when estimating the cost of capital.[516]

Although not discussed in detail in her testimony, she presented the calculations she performed to determine the "asset beta" in this analysis in her Schedule D5.13 for each of the proxy companies, computing both an asset beta with taxes and an asset beta without taxes. She then used the average asset betas for the proxy groups, with her "assumed debt beta" as shown in Schedule D5.13, to derive "equity betas" for DTE based on its book value capital structure. She then used these equity beta values in her CAPM and ECAPM models, with scenario 1 and scenario 2 inputs, to estimate the required return for DTE, as shown in her Schedule D5.14. The resulting values are also included in her Figure 17 at 6 Tr 1255.

In formulating her recommendations, Dr. Villadsen also testified that interest rates have risen since DTE's return on equity was last set, and are expected to rise further over the next few years, which she opined point to a higher equity ratio for DTE than was last established.[517] She also testified that the TCJA affected utilities differently than other companies, resulting in "reduced cash flows and increased volatility of cash flows for

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[516] See 6 Tr 1215.
[517] See 6 Tr 1207, 1219-1224.

DTE."[518] She also discussed stock market volatility, presenting information regarding the VIX index and SKEW index as measures of volatility.[519]

Additionally, Dr. Villadsen identified reasons she believes DTE has greater business risk than the proxy companies, citing its lack of a revenue decoupling mechanism or lost revenue adjustment mechanism, placing it "at increased risk of under-recovering its cost of service relative to some companies in the sample group."[520] Asserting that DTE "does have some regulatory mechanisms in place that are comparable to those of the proxy group companies," she also stated that it has a BBB+ credit rating that is comparable to the sample companies. She also identified Michigan's choice program, and the economy in DTE's service territory as risk factors,[521] its need for capital,[522] and its ownership of Fermi 2.[523]

b. Staff

Staff recommended that DTE's return on equity be set at 9.8%, based on a range of 8.9% to 9.9%, based on Mr. Megginson's testimony.

In his analysis, Mr. Megginson explained that his proxy group of 10 companies includes electric and combined electric and gas companies with net plant between $5 billion and $28 billion, approximately 50% or more of its revenues from regulated electric service, and an investment grade bond rating within three notches of DTE's. In addition, each company had to currently be paying dividends, had to be followed by at least two

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[518] See 6 Tr 1219-1220; also see 6 Tr 1233-1237.
[519] See 6 Tr 1230-1233.
[520] See 6 Tr 1264.
[521] See 6 Tr 1265-1267.
[522] See 6 Tr 1267-1268.
[523] See 6 Tr 1268-1269.

IBES analysts, and could not be involved in merger and acquisition activity. The resulting proxy group is shown on page 1 of Schedule D5 in Exhibit S-4.

He compared DTE to the proxy group as follows:

> The average authorized ROE of the proxy group is 9.69%. Schedule D-5, page 3 of 12 describes the realized return on common equity for the proxy group and DTE Electric from 2014 through 2018. The average return on equity over the 5-year period for the proxy group was 8.9% and for DTE Electric was 10.44%. Thus, on average, the proxy group's financial return did not reach its average authorized return on equity over the five-year period. However, DTE Electric earned over its authorized ROE of 10.00% on average over the period, earning well above its allowed ROE in 2014, 2016 and 2018 and earning its authorized in 2015 and 2017.[524]

Mr. Megginson presented a DCF analysis incorporating a semi-annual compounding formulation of the constant growth model, which he explained is the method used by FERC. In this formulation, he used the most recent quarterly dividend and the most recent three-months of stock market closing prices (August through October 2019), along with earnings growth rates from several sources, as shown on page 4 of Staff's Schedule D5. He derived a resulting average return for the proxy group of 8.76%.

Mr. Megginson also presented a CAPM analysis, using three different equity risk premiums, two he labeled historic risk premiums and the third he labeled a projected risk premium, along with Value Line betas and slightly different risk free rates. For the historic risk premiums, he used Ibbotson data over two time periods, the 1926-2018 period for which Ibbotson data is available, resulting in a risk premium of 6.91%, and the shorter 1952-2018 period to reflect only the years in which the Federal Reserve System has been responsible for monetary policy, resulting in a risk premium of 6.23%. Using the average

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[524] See 9 Tr 3296-3297.

risk-free rate of 2.90% with each of the two historical risk premiums resulted in returns of 7.25% for the full historical period and 6.82% for the Fed-Accord period.[525]

For the projected risk premium component of his CAPM analysis, he derived an "electric utility projected equity risk premium" of 7.45% by using Value Line's projected 60% increase in the median price of stock over the next 3-5 years, annualizing that to a price appreciation estimate of 12.47% per year, then adding Value's Line's projected 2.3% annual growth in dividends, subtracting Value Line's long-term Treasury bond yield forecast of 2.95% from the resulting 14.77% market projection, and multiplying the resulting market risk premium of 11.82% by the average beta for the proxy companies, as shown on page 7 of Schedule D5.[526] Adding the projected risk free rate of 2.95% to the 7.45% beta-adjusted market risk premium resulted in a return of 10.40%.

Mr. Megginson also presented what two versions of what he labeled a "bond yield + risk premium" analysis. In the first version, he added the historical spread from utility stock returns and utility bond yields of 4.53% as shown on page 10 of Schedule D5 to the to current long-term utility bond yields for both A-rated and BBB-rated bonds, resulting in returns of 8.05% and 8.40% respectively.[527] He also performed a version using the 7.45% projected risk premium he used in his CAPM analysis, reporting results of 11.97% and 11.32% for A-rated and BBB-rated bonds, respectively, as shown on page 10 of Schedule D5.[528]

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[525] See 9 Tr 3303-3304.
[526] See 9 Tr 3304-3305.
[527] See 9 Tr 3310-3311.
[528] See 9 Tr 3311.

In formulating his recommendation, Mr. Megginson also considered authorized returns from other state commissions from 2017 through the third quarter of 2019. He testified that the average returns were 9.73% in 2017, 9.62% in 2018, and 9.63% in 2019.[529] At 9 Tr 3313, he presented a table of his modeling results along with this data. He further explained his recommendation:

> The Company's request for a 10.50% ROE is burdensomely high and unfair to ratepayers and should be rejected by the Commission. Staff's recommended ROE of 9.80%, as noted earlier, is very reasonable considering it is near the high-end of Staff's ROE range, adheres to the Commission's request for prudence in ROE recommendations, is higher than the average ROEs awarded by other state commissions in 2016, 2017 and through September 2018, is higher than the average authorized ROE of Staff's proxy group at approximately 9.70%, and properly compensates the Company for its electric utility investment.[530]

c. ABATE

ABATE argues that DTE's return on equity should be set at 9.2%, based on a range of 8.7% to 9.7%. In his analysis, Mr. Walters adopted DTE's electric-only proxy group with 2 exclusions; he excluded El Paso Electric Company because it is the target of a major acquisition by JP Morgan Investment Management, and he excluded Unitil on the ground that it is not followed by Value Line Investment Survey.[531] His proxy group is shown in Exhibit AB-11.

For his CAPM analysis, Mr. Walters used Blue Chip Forecasts' projected 30-year Treasury yield of 2.5% and Value Line betas as shown in Exhibit AB-24. He testified that the proxy group average and median beta value of .58 is low relative to previous years,

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[529] See 9 Tr 3312.
[530] See 9 Tr 3313A.
[531] See 7 Tr 1844.

so he also calculated a five-year average beta for each proxy company, with a resulting average of .68. For the market risk premium, Mr. Walters used two different estimates. The first estimate of 8.5%, which he labeled a risk-premium estimate, was based on adding an inflation adjustment to the long-term historical real returns on the stock market.[532] The second estimate of 8.6%, which he labeled a DCF estimate, projected the expected market return using a version of FERC's two-step method.[533] He compared his results to historical measures and to other forecasts. The results of his CAPM analyses using each of these risk premium rates are presented in Exhibit AB-25.

Mr. Walters performed DCF analyses using a constant growth, a sustainable growth, and a multi-stage form of the model. He explained that used weekly high and low stock prices over a 13-week period and the most recently paid quarterly dividend as reported in Value Line in his modeling.[534] For the constant growth model, he relied on an average of profession analysts' earnings growth estimates taken from Zacks, MI, and Yahoo! Finance, with an average growth rate for the proxy group of 5.17%.[535] He presented the results of this DCF analysis in Exhibit AB-13. For the sustainable growth DCF modeling, Mr. Walters developed growth rates for each proxy company based on the percentage of the utility's earnings retained and reinvested in utility plant and equipment, which is calculated as 1 minus the dividend payout ratio as shown in Exhibit AB-14. He testified that a sustainable long-term earnings retention ratio is used to determine whether analyst growth projections can be sustained over an indefinite period

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[532] See 7 Tr 1867.
[533] See 7 Tr 1867-1868.
[534] See 7 Tr 1847-1848.
[535] See 7 Tr 1849.

of time, presenting his sustainable growth rates in Exhibit AB-15 and the results of a DCF analysis using these growth rates in Exhibit AB-16. For his multi-stage DCF analysis, Mr. Walters used different growth rates for three periods: the consensus analyst growth forecasts as a short-term growth rate for the first 5 years; a long-term growth rate of based on the projected growth in GDP from year 11 forward; and blended growth rates transitioning linearly from the short-term to long-term rates for the middle 5-year period.[536] He presented the results in Exhibit AB-18.

For his risk premium analysis, Mr. Walters developed two estimates of an equity risk premium. First, he looked at the difference between authorized rates of return for electric utility companies and Treasury bonds using annual data from 1986 forward. Second, he looked at the difference between authorized rates of return for electric utility companies and A-rated utility bonds over the same time period. His calculations, based on 5-year and 10-year rolling averages to smooth variability, are in Exhibits AB-20 and AB-21. Using the 5-year average risk premium relative to Treasury bonds of 6.77% and the projected Treasury yield of 2.5% produced an estimated return of 9.3%. Using the 5-year average risk premium relative to A-rated utility bonds of 5.56% and recent A-rated utility bond yields of 3.42%-3.67% produced an estimated return of 9.0%-9.2%; combining the risk premium with recent Baa-rated utility bond yields produced a return of 9.3%-9.7%.[537]

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[536] See 6 Tr 1852-1859.
[537] See 7 Tr 1863-1864.

Comparing the proxy group to DTE, he testified that the proxy group has an average credit rating of BBB+ from S&P while DTE's is one notch higher at A-, and the proxy group has an average credit rating of Baa1 from Moody's while DTE's is two notches higher at A2.[538] He testified that DTE's common equity ratio is higher than that of the proxy group, both as reported by S&P and by Value Line. He concluded that DTE has less risk than the proxy group.[539] Considering the range of results produced by his analyses, summarized in Table 10 at 7 Tr 1873, Mr. Walters explained that the low end of his range is based largely on the higher results of his DCF and CAPM analyses and the low end of his risk-premium analyses, and the high end of his range is based on the high end of his risk premium analysis, with 9.2% as the midpoint of his range.[540]

d. Attorney General

In his analysis for the Attorney General, Mr. Coppola also used the DCF and CAPM financial models, as well as a risk premium approach. Mr. Coppola testified that in selecting a proxy group, he began with the 38 electric utilities followed by Value Line, and then removed companies he considered "not appropriate comparable companies," including: 7 companies he considered too large and 4 companies he considered too small, 2 companies whose dividends are not growing, 5 companies recently involved in mergers or acquisitions, 2 companies with large foreign investments, 3 companies whose earnings declined significantly in 2017, Edison International due to its potential liability for

[538] See 7 Tr 1845.
[539] See 7 Tr 1846.
[540] See 7 Tr 1873.

California wildfires, and DTE's parent company DTE Energy.[541] The resulting proxy group of 18 companies, as well as the excluded companies, are shown in his Exhibit AG-1.22.[542]

For his DCF analysis, summarized in his Exhibit AG-1.18, Mr. Coppola relied on stock price information reflecting an average of the highs and lows for the 30 trading days up to and including September 30, 2019, and he relied on the projected dividend for 2020 from Value Line. He used growth long-term average growth rates based on Value Line projections of earnings per share for 2022-2024 and Yahoo! Finance projections of earnings per share over a five-year period. The average return for his proxy group was 8.31%, and he assessed the driving forces underlying the results at 9 Tr 3024.

For his CAPM analysis, presented in Exhibit AG-1.19, Mr. Coppola used a projected risk-free rate of 3.2%, above the October 2019 current yield on 30-year Treasury bonds of 2.2%, to recognize "sentiment in the market is fairly universal that interest rates will rise assuming continued economic expansion in the United States."[543] He used a market risk premium of 6.91% based on the Ibbotson Classic Yearbook. He testified that the resulting proxy group average return is 7.27%.[544] He also provided his assessment of the limited usefulness of the CAPM results.[545]

In his risk premium analysis, Mr. Coppola used the projected risk-free rate of return on 30-year Treasury bonds of 3.2% he used in his other analyses, the 1.69% historical difference between BBB-rated utility bonds and 30-year Treasury bonds, and the 4.25%

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[541] See 9 Tr 3015.
[542] Some companies are excluded for multiple reasons.
[543] See 9 Tr 3025.
[544] See 9 Tr 3026.
[545] See 9 Tr 3028-3029.

average historical return of utility common stocks over utility bonds to estimate a required return.[546] He presented his analysis in Exhibit AG-1.20, with the resulting estimated return of 9.08%.

In formulating his recommendations, Mr. Coppola considered that recent changes in the economic and interest rate environment in recent years have placed DTE "in a better position with respect to sales levels, interest rates, and uncollectible sales amounts." He considered DTE's access to the capital markets to be strong, citing DTE's recent debt issuance, its senior secured debt and commercial paper ratings, and DTE Energy's recent equity issuance.[547] He also discussed recent returns authorized by other state regulatory commissions, citing a steady decline from 1990, and presenting more recent rates in his Exhibit AG-1.21, along with information on debt financing by those companies following the rate orders. He testified that the average of the most recent returns authorized for his peer group companies is 9.58%, and that these companies have been able to obtain debt capital and competitive interest rates even with returns on equity well below 10%.[548] Explaining that his recommended return on equity of 9.25% is above the average returns he calculated for the peer group, he testified:

> First, long-term interest rates are currently at a low level, and although they certainly justify ROEs well below 9.25%, they could negatively impact the long-term cost of common equity if they were to increase significantly in the coming years. As such, while the cost of common equity I have calculated is an accurate assessment of expectations for the forecasted test year, significantly higher U.S. Treasury interest rates at or above the 3.2% level assumed in this rate case analysis may produce a different result should such higher interest rates become a reality. In this regard, a potential 10%

[546] See 9 Tr 3029.
[547] See 9 Tr 3031.
[548] See 9 Tr 3032.

> correction in utility stock prices due to higher interest rates would produce a 0.30% to 0.40% increase in the cost of capital under the DCF approach.
>
> Second, the Company's own witness calculated the cost of common equity for the electric peer group, before being adjusted upward for the ATWACC methodology, at 8.6% under the DCF approach and at 8.2% (its highest rate) under scenario 2 of the CAPM methodology.
>
> Third, I understand that the Commission may be reluctant to set a ROE for the Company at the true cost of equity of 8.19%. Regulatory commissions around the country have granted ROEs averaging 9.5% to electric utilities during 2018 and 2019, with only few cases granted at the 10.0% level. In fact, approximately 50% of the reported ROE decisions in electric utility rate cases reported by "Regulatory Focus" during this time frame are well below the average rate of 9.5%. Therefore, my recommended ROE rate of 9.25% in this case is reasonable and fair, if not generous, as a gradual transition to the true cost of equity.[549]

2. Disputed Issues

a. Proxy Group

Mr. Megginson critiqued Dr. Villadsen's proxy groups, objecting to the inclusion of very small and very large electric companies, and also objecting to her use of the gas-water proxy group:

> This proxy group is neither required nor necessary in the estimation of an adequate ROE for DTE Electric. Water and gas utilities are not comparable to electric utility operations. Because the OHRU proxy group is regulated and has regulated assets, does not mean they are comparable in any significant or meaningful way to an electric utility and its financial requirements. If the Company was unable to populate a proxy group of comparable electric utility companies, then other proxy measures may have been suitable. However, the Company already established a rather broad selection of regulated electric utility 6 companies and thus eliminated the need for a collateral proxy group.[550]

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[549] See 9 Tr 3033-3034.
[550] See 9 Tr 3300-3301.

Mr. Walters also objected to Dr. Villadsen's use of natural gas and water companies as proxies, characterizing it as an unnecessary step that only serves to increase the resulting returns on equity:

> DTE Electric is seeking to increase its retail electric rates. Because DTE Electric operates in the regulated electric utility industry, and its stock is not publicly traded, companies that are traded within the same industry best serve as a proxy for estimating the cost of equity for DTE. Natural gas and water utility companies are exposed to different risks, and operate in different industries than DTE. As such, they do not resemble a proxy for DTE electric.
>
> It would be one thing to look at other regulated industries to help inform an analyst if the subject company operated in an industry that did not have ample equity and credit analyst coverage, or if there were so few companies within the industry that a well-defined proxy group could not be developed. But, this is not the case for the electric industry. The breadth of companies currently in the electric utility sector far outnumber the number of companies within the natural gas and water utility sectors. This is apparent as her electric company sample is nearly double her consolidated OHRU sample that includes only water and natural gas utilities. Because of the ample coverage and breadth of companies occupying the electric utility sector, water and natural gas companies do not add value to informing an analyst in estimating the investor required return for the electric utility industry in general, or DTE specifically. [551]

Related to his concern with her selection of these proxy companies, Mr. Walters also objected that Dr. Villadsen did not include a review of authorized returns on equity for these companies in her risk premium analysis or otherwise.[552] Mr. Walters testified that none of Dr. Villadsen's results for the electric proxy group, including many other modeling choices he objected to, reached the level of her 10.5% return recommendation.[553] Mr. Walters presented a table of Dr. Villadsen's results only for her

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[551] See 7 Tr 1881.
[552] See 7 Tr 1881.
[553] See 7 Tr 1882.

electric proxy group and the combined electric-gas-water group to show the underlying model results, the ATWACC adjustment, and the results she based her recommendation on to show that those values are predominantly well below her recommended range.[554]

Mr. Coppola compared his proxy group to the proxy companies used by DTE, and testified that both the electric proxy group and the gas-water proxy group Dr. Villadsen selected suffer from significant shortcomings and should be rejected. Regarding the electric companies she selected, he objected that four of them are very small in size, which "makes the trading of their common stock and public debt less liquid, increasing the cost of capital." He also objected to her inclusion of Southern Company and Edison International:

> Southern Company continues to face financial challenges with the construction of two nuclear plants and has been selling assets to pay for cost overruns. The risk profile of this company is not comparable to DTE Electric or other utilities in the peer group. Regarding Edison International, the company reported in its Form 10K filed with the Securities and Exchange Commission that it set up a reserve in the fourth quarter of 2018 of $1.8 billion after-tax associated with wildfire risks prior 2019. Wildfires were a major factor that forced Pacific Gas & Electric into bankruptcy.[555]

Regarding her use of natural gas and water companies, he disputed her contention that reliance on these other companies is appropriate given the changes occurring in the electric utility industry:

> The electric industry has been going through changes for many years. This does not mean that an appropriate peer group of companies that are going through similar changes is not an appropriate comparable group to use to establish the appropriate cost of capital. The peer group of 18 companies I have assembled achieves that objective without venturing into companies in the water and natural gas businesses.[556]

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[554] See 7 Tr 1874-1876.
[555] See 9 Tr 3019.
[556] See 9 Tr 3018.

He further testified that there are more significant differences than similarities between electric utilities and natural gas and water companies:

> Electric utilities generally are integrated companies with generation and distribution, while natural gas and water utilities are primarily distribution companies. Electric utilities also tend to be much larger companies with larger market capitalization, and therefore easier access to capital, which lowers their cost of capital. Additionally, electric utilities face more environmental regulation than natural gas and water utilities due to emissions from power generation. These differences more than overcome any superficial similarities that witness Villadsen may perceive.[557]

Dr. Villadsen objected to criticisms of her proxy group, reiterating her testimony that the electric industry is undergoing substantial changes as justification. She also took offense to the suggestion that it is outcome determinative on her part to make this selection.[558] Dr. Villadsen objected to Mr. Megginson's size restrictions, which she characterized as arbitrary and unnecessary.[559] She agreed with Mr. Walters's exclusion of El Paso due to merger activity, but disputed his exclusion of Unitil, contending she was able to obtain Value Line data for that company.[560]

Dr. Villadsen also noted Mr. Walters's use of a five-year average of betas in his CAPM analysis, contending that this tacit acknowledgement that betas should be higher is a confirmation of her use of a proxy group of gas and water companies.[561]

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[557] See 9 Tr 3018.
[558] See 6 Tr 1332-1334.
[559] See 6 Tr 1335.
[560] See 6 Tr 1336-1337.
[561] See 6 Tr 1338-1339.

b. DCF

In her rebuttal, Dr. Villadsen objected to Staff's use of the half-growth-rate convention, with a similar objection to the model formulation used by Mr. Coppola.[562] She also objected to Staff's use of the average of Yahoo, Value Line and Zacks growth forecasts as containing substantial overlap.

Dr. Villadsen objected to Mr. Walters's statement of his results from his sustainable growth rate model, contending that his quotes do not match the numbers presented in Exhibit AB-15. She testified that his projected risk premiums show estimates of 10.97% and 11.32%, 200 basis points above historical, and yet he dismisses these results. She recommended the Commission place greater weight on them. She testified that Mr. Walters failed to consider the relationship between the risk free rate and risk premium investors require, citing "empirical evidence" the return on equity does not increase or decrease by 1% when the risk free rate does.[563]

c. CAPM/ECAPM

Mr. Megginson objected to Dr. Villadsen's use of the ECAPM, in part based on her use of adjusted betas in the model, and in part based on her use of a short-term projected market risk premium in the model.[564] He testified that Staff's reliance on long-term risk free rates and adjusted betas "incorporates much of the desired effect of the ECAPM adjustment."[565] He also described the Hamada adjustment Dr. Villadsen used, indicating it tends to increase the resulting returns.

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[562] See 6 Tr 1340, 1341.
[563] See 6 Tr 1341-1343.
[564] See 9 Tr 3306-3308.
[565] See 9 Tr 3308.

Mr. Walters also objected to Dr. Villadsen's use of adjusted betas in her ECAPM analysis. Citing a published article as well as presenting an illustrative graph, Mr. Walters testified:

> Dr. Villadsen included an adjusted beta within her ECAPM studies. This adjustment is inconsistent with the academic research supporting the development of an ECAPM methodology. Bottom line, using adjusted betas within an ECAPM study double counts the purpose of the ECAPM study – that is, to flatten the security market line and increase a CAPM return estimate for companies with betas less than 1, and decrease the CAPM return estimate for betas greater than 1. Dr. Villadsen discusses the objective of the ECAPM at pages 44-49 of her testimony. As shown in Dr. Villadsen's Figure 6, the ECAPM will raise the intercept point of the security market line and flatten the slope. Again, this has the effect of increasing CAPM return estimates for companies with betas less than 1, and decreasing the CAPM return estimates for companies with betas greater than 1. Importantly, however, the use of an adjusted beta such as those published by Value Line, produces comparable adjustments to the security market line and CAPM return estimate. In effect, using an adjusted beta within an ECAPM study has the effect of a double adjustment to the slope and intercept of the security market line. [566]

Mr. Walters objected to Dr. Villadsen's use of Treasury rate forecasts he characterized as stale and unreasonably high. He testified at 7 Tr 1886-1887 that her use of 3.50% exceeds the current consensus projection for the 30-year Treasury yield of 2.50%, further contending this casts doubt on her assertion that investors are expecting interest rates to rise.

Mr. Coppola also critiqued Dr. Villadsen's CAPM analysis on other grounds. He objected to the two scenarios she constructed, characterizing her use of a 7.91% risk premium "highly unconventional and solely based upon witness Villadsen's opinion that

[566] See 7 Tr 1885.

MRP rates have escalated since the 2007-2008 financial crisis."[567] His chart at 9 Tr 3027 also identifies each of the factors contributing to the different results between his CAPM analysis and DTE's. He further objected to Dr. Villadsen's use of the ECAPM, characterizing it as subjective, unconventional, and not supported:

> In her testimony, witness Villadsen did not specify if the ECAPM was utilized to set rates in other jurisdictions. However, in Case U-18999 the witness for the Company's affiliate, DTE Gas Company, was able to identify only the Alberta Utilities Commission of Canada. In its order of October 7, 2016, the Alberta regulatory commission noted on page 45, paragraph 199 of the order that the ECAPM "…appears to be a model that could contribute to the Commission's determination of a fair allowed ROE…." However, later in the same paragraph, that commission noted the high degree of judgment required by the ECAPM methodology and the Alberta Commission and added this statement: "Consequently, the Commission will not rely heavily on the ECAPM results in this proceeding…"[568]

In his rebuttal testimony, Mr. Coppola addressed Mr. Megginson's analysis, taking issue with Mr. Megginson's use of a projected market risk premium of 11.82% in one of his CAPM analyses. He objected that this rate reflects projected stock price appreciation, which he considers "very speculative," and too short-term in nature to reflect economic cycles, further discussing his concerns.[569]

In his rebuttal testimony, Mr. Walters also objected to Mr. Megginson's projected risk premium, characterizing it as based on an unsustainable growth rate and expected return on the market.[570] Presenting a chart in Table 2 of his rebuttal testimony at 7 Tr 1810, he testified that the market has not realized sustained long-term periods of total returns greater than or equal to 14.77% He also cited a Staff discovery response in

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[567] See 9 Tr 3027.
[568] See 9 Tr 3028.
[569] See 9 Tr 3100-3102.
[570] See 7 Tr 1908-1911.

Exhibit AB-34, acknowledging that Staff did not perform any analyses to test the reasonableness of his expected return on the market. Mr. Walters also objected that Mr. Megginson's use of a projected Treasury bond rate of 2.95% is excessive.[571]

Dr. Villadsen also took issue with Mr. Megginson's use of an historical market risk premium based on the Ibbotson data only from 1952 through 2018.[572] She did agree in theory with his "projected CAPM" with a projected market risk premium, noting that it produced a result 200 basis points higher than his other estimates. She asserted in this context that she finds puzzling his testimony objecting to her use of an MRP of 7.91% as too high.[573] Dr. Villadsen also objected that none of the other analysts used her elevated market-risk premium.

d. Risk Premium

Mr. Megginson expressed a concern regarding DTE's risk premium analysis, objecting to Dr. Villadsen's reliance on authorized rates of return, characterizing it as circular reasoning "because the end goal of this proceeding is to drive a Commission-authorized ROE that is specifically appropriate for DTE Electric and the test period in this case."[574]

Mr. Walters objected to Dr. Villadsen's reliance only on a linear relationship between authorized returns and Treasury rates in her risk premium analysis:

> This overly simplistic relationship is not based on basic risk and return valuation principles. While academic studies have shown that there has been a linear relationship between these variables in the past, these studies have found that the relationship changes over time and is influenced by

[571] See 7 Tr 1912.
[572] See 6 Tr 1338.
[573] See 6 Tr 1338.
[574] See 9 Tr 3311.

> changes in perception of the investment risk of bond investments relative to equity investments, rather than only changes to nominal interest rates.[575]

He also testified that updating the Treasury rate in her analysis to 2.3% produced an electric equity risk premium of 7.41% and a cost of equity estimate of 9.71%.

Mr. Coppola also objected to Dr. Villadsen's risk premium analysis, describing it as not a traditional analysis "in the sense of measuring achieved returns on utility stocks relative to an interest rate benchmark such as utility bonds."[576] He further objected to reliance on her regression of state authorized returns on equity to Treasury bill rates:

> What is troubling about this analysis is that it lacks any comparison of actual returns achieved on utility common stocks (via price appreciation and dividends) to treasury bonds, and suggests that treasury bond yields are the primary driver in ROE decisions by regulators. This analysis has no validity as a tool to determine the ROE to be established in rate proceedings. Regulators approach the serious business of establishing a ROE based on many factors and often exercise "gradualism" in the process as well. The Commission should give this analysis no weight in this case.[577]

Mr. Coppola expressed the same concern with Mr. Megginson's use of a projected beta-adjusted market risk premium of 7.45% in his bond yield + risk premium analysis as he did with his use of a projected market risk premium in the CAPM analysis. He further objected to this analysis on the basis that the beta-adjusted market risk premium was derived relative to the Treasury rate, rather than to the bond yields, testifying that the result of applying the risk premium to the expected bond yield "incorporate[s] an extra premium equivalent to the difference of the utility bond rate and the U.S. Treasury rate."[578]

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[575] See 7 Tr 1888.
[576] See 9 Tr 3030.
[577] See 9 Tr 3031.
[578] See 9 Tr 3103.

Mr. Walters took issue with Mr. Megginson's projected bond yield + risk premium method, objecting to his use of the same risk premium he used in his projected CAPM analysis, for the same reasons discussed above. He also objected that this risk premium was derived as an equity risk premium over the Treasury bonds, but is used in this analysis in combination with bond yields:

> The result is a fatally flawed application of a risk premium analysis that contains mismatches, incorrect assumptions, and incorrect inputs. Mr. Megginson essentially created his own version of the CAPM and called it a projected bond yield plus risk premium method. As such, Mr. Megginson's projected bond yield plus risk premium should be given no weight.[579]

In her rebuttal testimony, Dr. Villadsen acknowledged she used a forecast risk-free rate based on long-term Treasury yields that is higher than current forecasts, but asserted that her estimate was reasonable based on the time period at which it was made.[580] Dr. Villadsen defended her use of the ECAPM with adjusted betas in her rebuttal testimony.[581]

e. ATWACC and Hamada Leverage Adjustment

Mr. Megginson objected to Dr. Villadsen's use of the ATWACC adjustment to her proxy group results:

> The ATWACC approach takes market weights for equity and debt to establish a market value overall rate of return for the proxy group. The approach then attempts to recreate the same overall market value rate of return using book weights or rate case weights of debt & equity of the Company. If the market weight for equity is higher than debt, which is normally the case, then to obtain the same overall market return, it will most always require a higher cost of equity. Thus, the approach takes traditional

[579] See 7 Tr 1914.
[580] See 6 Tr 1337.
[581] See 6 Tr 1345-1347.

model DCF results and runs them through additional steps to produce higher yet more skewed results.[582]

Mr. Walters also objected to Dr. Villadsen's ATWACC adjustment and to her related Hamada adjustment, testifying that it is not commonly accepted in electric rate-setting proceedings, and noting that the Commission rejected this adjustment in Case Nos. U-18014 and U-18255.[583] He further explained:

> An obvious concern is that DTE Electric's common stock is not publicly traded and therefore there is not a market value capital structure to compare to those of the proxy companies. If there was, the process of developing a group of comparable risk companies to rely on in estimating the cost of DTE's equity would be moot since the cost of equity capital could be established by applying these models directly to DTE's stock. Because DTE does not have a market value capital structure to use as a comparison to the proxy companies' market value capital structures, it is reasonable to assess the financial risk of DTE relative to the proxy companies using the book value capital structures since all companies have book value capital structure. The book value capital structure is used, in part, to support the valuations assigned to each of the companies in the sample (i.e. the market-to-book ratio or "M/B"). As shown on my Exhibit AB-10, the book value common equity ratio of DTE indicates that it has a comparable amount of financial risk to that of the proxy group, if not less. While DTE is not a publicly traded company, Dr. Villadsen has provided no reason to believe that DTE's common equity would be valued in the market substantially different than the sample companies' equity. Therefore, if one were to assume if DTE's common equity were publicly traded, we could apply the sample's M/B ratio to DTE's book value common equity. This would lead to the conclusion that DTE does not face any more financial risk than the average sample company.[584]

He expressed similar concerns to her use of the Hamada levered betas:

> [I]n similar fashion to her ATWACC adjustment, Dr. Villadsen deleverages the betas for the sample companies' market value capital structures, and re-leverage them using DTE's requested book value capital structure and an assumed debt beta of 0.10. As I have discussed above, because DTE's stock is not publicly traded, and Dr. Villadsen has provided no reason to

[582] See 9 Tr 3301-3302.
[583] See 7 Tr 1880.
[584] See 7 Tr 1878-1879.

> believe DTE would be valued (i.e., M/B) any differently than the sample group, the book value capital structure of DTE relative to the book value of the sample is the relevant comparison.[585]

Additionally, similar to his concerns with Dr. Villadsen's use of the ECAPM with Value Line adjusted betas, he objected to her use of Value Line adjusted betas along with the empirically-determined Hamada adjustments:

> Dr. Villadsen's application of the Hamada adjustment in her CAPM and ECAPM analyses is inappropriate in determining DTE's cost of equity. While the Hamada adjustment may be an empirically recognized adjustment to raw or unadjusted beta estimates, it has not been shown to be applicable to an already-adjusted Value Line beta. While Dr. Villadsen discusses at length the appropriateness for each individual adjustment she makes to the CAPM model and its components, she has not provided empirical support for all the adjustments she makes to be used in concert with one another.[586]

Mr. Coppola objected to Dr. Villadsen's use of the ATWACC approach to increase the results of her DCF and CAPM analyses, presenting a chart at 9 Tr 3022 to show the increases to her DCF results from using this approach, and presenting a chart at 9 Tr 3027 to show the increases to her CAPM results from using this approach. He testified:

> The key factor causing the escalation in the ROE is the high stock market to book value of the common equity for each company in the analysis.
>
> The resulting effect of this ATWACC approach is that the high stock market to book ratios in the utility industry, due primarily to high ROEs vs. low interest rates, artificially inflates the cost of common equity. This is a major fault of the ATWACC approach that, if embraced by regulatory commissions, would lead to higher inflated ROEs awarded in rate cases.[587]

He further explained the circularity he believes would result from adopting this method:

> For example, if the ATWACC approach was to become universally embraced by regulatory commissions, the ROEs awarded in regulatory proceedings would increase. These inflated ROEs would then result in

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[585] See 7 Tr 1884.
[586] See 7 Tr 1884.
[587] See 9 Tr 3022.

> higher utility earnings, higher stock prices and higher market to book ratios for utility common stocks. The subsequent calculated ROEs in new rate cases under the ATWACC method would then produce even higher awarded ROEs because the ATWACC would use the higher stock market equity capitalization.[588]

In her rebuttal, Dr. Villadsen contended that the other analysts ignore the effects of leverage, which she characterized as a basic tent of financial theory,[589] and defended her leverage adjustments.[590] She disputed that the adjustment is circular, testifying that the weighted average cost of capital does not change with the cost of capital and is thus unaffected by financial risk.[591] She responded to Mr. Walters's testimony considering her adjustment essentially a market-to-book adjustment by saying first that he misconstrues her approach as claiming DTE's financial risk is greater than comparable companies.[592]

She specifically addressed her use of the Hamada approach at 6 Tr 1328.

f. Other Authorized Returns

Mr. Walters testified that the average authorized returns presented in Staff's analysis were incorrect, presenting Table 1 at 7 Tr 1907 to show the corrected averages.[593] Mr. Coppola also noted Staff's reliance on authorized returns from other jurisdictions, and contended that 2017 authorized returns are stale.[594]

g. Other Risk Factors

Dr. Villadsen disputed Mr. Walters's reliance on credit agency reports regarding DTE, testifying that credit rating agencies only describe bond risk. Further, she testified,

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[588] See 9 Tr 3023.
[589] See 6 Tr 1313-1319, 1339.
[590] See 6 Tr 1318-1332.
[591] See 6 Tr 1323.
[592] See 6 Tr 1319.
[593] See also 7 Tr 1918.
[594] See 9 Tr 3104.

all the proxy companies are highly-rated so differences in credit rating do not make a difference for the cost of equity."[595]

Mr. Walters objected to Dr. Villadsen's contention that DTE is of higher risk than the sample companies, characterizing her analysis as incomplete and inaccurate. In his view, she has "cherry-picked risks potentially faced by DTE without considering other unique risks faced by the proxy group companies." He testified that had rating agencies deemed these particular risks detrimental, they would have taken them into consideration. He also disputed that DTE's capital needs are not unique to DTE.

3. Discussion

DTE relies on Dr. Villadsen's analysis in its brief.[596] In response to the critiques of other witnesses, DTE relies on her rebuttal testimony in defense of her use of adjusted Value Line betas in the ECAPM, her use of the ATWAAC model and the Hamada adjustment, her use of natural gas and water companies in her proxy group, and her choice of inputs. DTE objects that Mr. Megginson, Mr. Coppola and Mr. Walters used annualized dividend yields rather than quarterly dividend yields in their single-stage DCF models, objected that Staff relied on what it labels "overlapping" growth rate estimates, and contends that ABATEs sustainable growth rate is not properly implemented.[597] DTE also cites the Commission's recent orders discussing DTE's cost of equity capital and DTE Gas Company's cost of equity capital, arguing that the Commission has acknowledged that increased volatility would justify a higher return on equity, and also

[595] See 6 Tr 1315.
[596] See pages 96-107.
[597] See DTE brief, page 101.

acknowledging that economic conditions in parts of DTE's service territory remain challenging. DTE also cites Dr. Villadsen's testimony that interest rates are expected to increase going forward. And it argues the TCJA has led to reduced cash flows, "putting DTE at risk for a credit downgrade."[598] It further argues that DTE's unique circumstances justifying a higher return on equity include rising interest rates, required compliance with environmental regulations, low electric demand growth, the lack of an RDM or fixed variable pricing, Michigan's economy, the need for capital to improve reliability, and "asymmetrical" risk from Fermi 2 due to the responsibilities of owning and operating a nuclear plant, as well as the connection between its cost of equity and its capital structure.[599]

In its brief, in support of its recommended return on equity of 9.8%, Staff emphasized Mr. Megginson's disagreement with DTE's use of gas and water utilities as a proxy group, its use of the ATWACC to adjust the proxy group return results, its use of the ECAPM and Hamada modification of the CAPM model, and with DTE's use of authorized returns on equity as an input to its risk premium analysis. Staff also addressed DTE's rebuttal testimony, defending Staff's use of the half-growth-rate convention in its DCF analysis as the method preferred by FERC,[600] Staff also defended its use of multiple sources for estimated growth rates against criticism from Dr. Villadsen[601] and defended

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[598] See DTE brief, pages 103-104.
[599] See DTE brief, pages 105-106.
[600] See also Megginson, 9 Tr 3299.
[601] See Staff brief, pages 49-51.

its CAPM and risk premium analysis in response to Mr. Coppola's and Mr. Walters's rebuttal testimony.[602]

In its brief, ABATE urges the Commission to adopt Mr. Walters's analysis. As discussed above, Mr. Walters took issue with elements of Dr. Villadsen's analysis, contending that her recommended return for DTE is unreasonable.[603] ABATE argues that consideration should be given to customers as well as investors, citing several cases in support of its argument.[604] ABATE further argues that the market views utility stocks and bonds as low-risk securities. It also argues that interest rates are flat to declining, citing cross-examination of Dr. Villadsen. It contends DTE's recommended return is out of touch with recent state commission awards, based on an invalid forecast of interest rates, high growth rates in its DCF model that are not sustainable, inflated market-risk premiums, and incorrect betas in the ECAPM analysis.[605]

The Attorney General urges the Commission to adopt Mr. Coppola's analysis and an authorized return on equity of 9.25%.[606] The Attorney General objected to DTE's reliance on gas and water company proxies, also arguing that some of the natural gas companies she selected have substantial non-utility business, and taking issue with several of the electric companies.[607] The Attorney General objects to DTE's DCF analysis, use of the ATWACC approach, and other choices that the Attorney General describes as "inventive, highly unconventional, not generally accepted, and . . . based in

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[602] See Staff brief, pages 53-57.
[603] See 7 Tr 1877-1889.
[604] See ABATE brief, pages 25-26.
[605] See ABATE brief, pages 44-45.
[606] See Attorney General brief, pages 91-108.
[607] See Attorney General brief, pages 95-98.

part upon DTE's own opinion that risk levels have permanently risen since the 2007-2008 financial crisis."[608] The Attorney General argues that low interest rates should no longer be viewed as a temporary phenomenon, and emphasizes Mr. Coppola's testimony that a return of 9.25% will not impair DTE's access to capital markets.

Walmart addressed the return on equity in its brief, citing Mr. Chriss's general concerns with the use of projected rate base and the inclusion of Construction Work in Progress in rate base. Walmart argues that DTE's proposed return on equity is excessive and will have adverse customer impacts. Soulardarity also addressed the return on equity in its brief, arguing that the Commission should reject DTE's proposed increase and approve a return more consistent with the Attorney General's and ABATE's recommendations:

> In this case, DTE fails to satisfy adequately several elements of these tests for increasing its ROE. DTE's obsolete equipment and corresponding lack of reliability, its questionable estimation of economic risks related to its business, and the low quality and value of service provided to certain ratepayers do not justify DTE's proposed ROE. The Commission would be operating well within the bounds of its authority if it rejects DTE's request. "[T]he PSC has direction to set the rate at the level it chooses" so long as "the rate [] is neither so low as to be confiscatory nor so high as to be oppressive." Thus, Soulardarity urges the Commission to reject DTE's request to increase its ROE to 10.5% and instead adopt the rates proposed by other intervenors in this case. [609]

This PFD finds that DTE has failed to justify a higher return on equity for the projected test year. DTE has not shown an increased risk attributable to the TCJA, and presented no analysis of its current or projected credit metrics. The Credit A and Credit B

[608] See Attorney General brief, pages 101-102.
[609] See Soulardarity brief, pages 39-40.

refunds have been completed; the Commission has approved DTE's proposed gradual reduction in its accumulated deferred tax balances, and as those balances decrease, the equity percentage of the ratemaking capital structure will increase and correspondingly, the income component of DTE's revenue requirements calculation will increase. In addition, DTE has had multiple rate increases since the passage of the TCJA.

DTE has not shown that market volatility presents an increased risk. Dr. Villadsen presented index data from January 2000 through March 2019 for the VIX and SKEW indexes. She testified that although the VIX index, which measures market volatility, has recently been below its 30-year average of 19.3, with spikes above that in October and December 2018, the SKEW index, which measures the market's willing to pay for protection against sudden downturns, has generally been on an upward trend. See 6 Tr 1231-1232. Dr. Villadsen uses this to support her claim that investors require higher risk premiums and thus higher returns. She acknowledges, however, that "investors are willing to pay for protection against downside risk."[610] Utility stocks represent protection from that downside risk, as is also reflected in lower utility stock betas, which reflect that utility returns are less correlated with market returns than in the past.

DTE's own analysis of the cost of equity has many shortcomings. First, this PFD finds that DTE did not establish that it is reasonable or appropriate to rely on the application of cost of capital models to a proxy group including gas or water companies. The Commission endorsed the ALJ's concern with reliance on water companies in DTE Gas's most recent gas rate case, Case No. U-18999, stating that "The ALJ correctly

[610] See 6 Tr 1232.

questioned the relevance of DTE Gas' proxy group based on the heavy reliance on the water utility industry."[611] Interestingly, in that case that was litigated in 2018, DTE Gas argued that it needed to include water companies in its proxy group due to the prevalence of merger and acquisition activities among the gas companies.

Second, the range of return estimates presented by Dr. Villadsen include results from an ECAPM with questionable inputs. Notwithstanding Dr. Villadsen's testimony asserting that the empirically-determined adjustments Value Line betas do not duplicate the empirically-determined ECAPM alpha-values, this PFD finds Mr. Walters's, Mr. Coppola's and Mr. Megginson's testimony persuasive that the two adjustments are duplicative. Third, the Commission has already rejected the ATWAAC method of adjusting proxy group results, and DTE has not presented new or persuasive evidence that the Commission's decision was erroneous. Indeed, Dr. Villadsen's rebuttal testimony admits the truth of Mr. Walters's criticism that the goal is essentially a market-to-book-value adjustment to compensate investors in DTE Energy at the authorized rate of return relative to their market-price investment in DTE Energy:

> Most utilities have a much greater share of debt in their book capital structure than in their market value capital structure, i.e., they are more leveraged in book terms. As a result if the market cost of equity were granted against the book amount (cost basis), the utility shareholders would not be earning enough to offset the risk of full cost recovery. The additional debt in the book capital structure simply puts investors at risk for non-recovery. The leverage adjustment in turn takes this additional leverage into account and adjust the allowed return of equity from the market measured rate just enough to ensure the risk of cost recovery is compensated. Making the adjustment keeps investors whole, and the equity

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[611] See September 13, 2018 order, page 53.

> competitive with other investment opportunities, exactly as sought under Hope and Bluefield.[612]

As if this testimony was insufficiently clear, Dr. Villadsen testified as follows, addressing Mr. Walters's point that DTE stock is not publicly traded:

> It is perplexing that Mr. Walters should point to this fact since it describes the posture of many regulated electric utilities and in no way diminishes the need to (1) estimate the cost of equity based on market data and (2) ensure equity investors in DTEE are accurately compensated for the risk they take on.[613]

Fourth, Dr. Villadsen's risk-free rate projections are based on stale data. Not only do the other analysts present more current and lower projected Treasury rates, she also acknowledged that interest rates had fallen since her analysis in March 2019. Fifth, Dr.'s 25-basis-point increase to the risk-free rate (in her scenario 1) or 100-basis-point increase to the market-risk premium (in her scenario 2) to reflect an elevated return requirement, is unsupported.[614]

Indeed, a review of the collective results of the models presented by the analysts show results generally consistent with a reduction in the required return on equity over the last couple of years. As the Attorney General argues, interest rates are no longer projected to rise. The collective analysis of the parties including DTE's analytic results as presented in Mr. Walters's table at 7 Tr 1875, as well as Mr. Megginson's, Mr. Coppola's, and Mr. Walters's analysis, establish that the return on equity should not be set higher than 9.8% as recommended by Staff. Thus, this PFD recommends that the Commission adopt Staff's recommended return on equity of 9.8%.

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[612] See 6 Tr 1321.
[613] See 6 Tr 1322.
[614] See 6 Tr 1321.

D. Overall Weighted Cost of Capital

As shown in Appendix D, this PFD recommends a weighted average cost of capital of 5.42%, based on an authorized return on equity of 9.8%, a cost of long-term debt of 4.22%, a cost of short-term debt of 2.73%, and the capital structure proposed by DTE.

VII.

ADJUSTED NET OPERATING INCOME

Net operating income (NOI) constitutes the difference between a company's operating revenue and its operating expenses including depreciation, taxes, and allowance for funds used during construction (AFUDC). Adjusted NOI includes the ratemaking adjustments to the recorded test year NOI for projections and disallowances.

A. Revenue

1. Residential and Commercial Sales

Mr. Leuker presented DTE's projected test year sales forecast by rate class that underlies DTE's revenue projections.

Mr. Coppola took issue with the projected sales declines for residential and commercial customers. He analyzed historical weather-adjusted sales for these classes from 2014 through 2018 in comparison to DTE's projections for 2019 through the end of the projected test year, as shown in Exhibit AG-1.25. He also calculated weather-normalized sales per customer for each class, showing an average decline of .91% for residential customers measured on both a 3-year and 4-year basis, and an average decline of .49%-.71% for commercial customers, measured on a 3-year and 4-year basis.

Mr. Coppola testified that DTE's projected decline in sales per residential customer is .5% for 2019, 1.7% for 2020 relative to 2019, and 2.2% for the projected test year ending April 2021 relative to 2019. Similarly, he testified that DTE's projected decline in sales per commercial customer is 1.1% for 2019, 1.5% for 2020 relative to 2019, and 1.9% for the projected test year relative to 2019.

Mr. Coppola concluded that theses rate of decline are not supported by the historical average rates of decline. After reviewing discovery responses regarding DTE's energy waste reduction assumptions, he testified:

> Whether the Company is using the historical EWR sales reductions rate of 1.5% or the higher projected rates of sales decline in the regression model or subsequent adjustments made to the model, these assumptions overstate the actual rate of decline experienced over the past three to four years. At most, approximately half of those rates of decline in sales has been experienced during the 2014 to 2018 period. This means that either the targeted EWR or energy efficiency targets are not actually being achieved or something else is partially offsetting the EWR sales declines. In either case, the sales for the projected test year are significantly understated.[615]

He also considered the potential impact from distributed generation resources, reviewing DTE discovery responses showing projected sales offsets for the projected test year of 102 GWh or 0.2% of combined residential and commercial sales, also noting that DTE relied on nationwide forecasts from the Energy Information Administration rather than its own historical information:

> The rates of growth of 9% for residential DG and 6% for non-residential used by Mr. Leuker likely reflect areas of the country where DG evolved more quickly than in Michigan. Therefore, such broad assumptions are not likely applicable to DTEE's customer base. In discovery, the Company was asked to explain why these growth rates apply to its customers. In its response, the Company simply pointed to the EIA report with no further explanation.[616]

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[615] See 9 Tr 3040.
[616] See 9 Tr 3041.

Mr. Coppola found DTE's use of the DG growth forecasts to develop projected sales offsets "more troubling":

> Discovery response STDE-2.1b, included in Exhibit AG-1.26, shows that DG volumes have been forecasted at 126 GWh by 2021. This represents an increase of 114% from the amount of 59 GWh in 2019, or an average increase of nearly 60% per year over the two-year period. Such a growth trend over a two-year period is not credible. This incredible growth trend, combined with the exaggerated EWR sales reductions discussed earlier, render the Company's sales forecast for the projected test year unreliable.[617]

After observing the potential rate impact of even a 1% forecast error, Mr. Coppola recommended that the Commission limit projected sales declines for the residential class and for commercial customers under General Service Rate Schedule D3 to the historical rates of decline in sales per customer. He explained the limitation to Rate Schedule D3 customers: "Restricting my adjustment to sales for only these customers is a conservative step and considers the declines in industrial sales projected by the Company."[618] The calculations underlying his adjustments are shown in Exhibits AG-1.27 and AG-1.28. He testified that his adjustments increase test year residential sales by 127,842 MWh and commercial sales by 112,687 MWh, and that the combined impact is a $12.17 million increase in test year revenue at present rates.

In his rebuttal testimony, Mr. Leuker characterized Mr. Coppola's analysis as overly simplistic, objecting that he did not specifically consider the growth in energy waste reduction (EWR), the adoption of customer-owned generation, plant openings and closing or the current and future state of the economy. For residential sales, Mr. Leuker testified:

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[617] See 9 Tr 3041

[618] See 9 Tr 3043.

The combined impact of a growing EWR program and the loss of sales attributable to growth in customer-owned generation will lower residential sales by 446 GWh from the 2019 forecast. When we add back customer growth between 2019 and the rate case test year of 236 GWh, the company is forecasting a net decline in sales of 210 GWh in the residential class.[619]

Regarding commercial and industrial sales, Mr. Leuker testified:

Witness Coppola's simplistic CAGR approach does not capture changes due to the expansion of the EWR program and the increased growth in customer-owned generation for the rate case test year versus the historical years used in his analysis. Combined, these two factors account for a 355 GWh decline in sales from the 2019 forecast to the rate case test year.[620]

Mr. Leuker also presented a revised version of Mr. Coppola's analysis in his Exhibit A-38 using data from the first 10 months of 2019:

For the Residential market, the 4-year CAGR for residential UPC fell from -0.91% (2014-2018), as shown in Witness Coppola's Exhibit AG-1.25, to -1.02% (2015- 2019). Extrapolating the UPC CAGR out to the test year from 2019 weather normal actuals would result in a UPC forecast of 7.298 MWh/customer which is the same as the UPC provided in the Company's forecast for the test year. Therefore, utilizing Witness Coppola's approach updated for 2019 actuals, suggests the Company slightly under-forecasted test year sales in the residential market by 1 GWh (original test year of 14,724 GWh compared to test year using 4-year CAGR of 14,725 GWh), as opposed to having under-forecasted by 128 GWh as Witness Coppola suggests on page 89 of his Direct Testimony.[621]

In its brief, the Attorney General argues that a simple forecast is not necessarily wrong or flawed. The Attorney General cites Mr. Leuker's acknowledgement that Mr. Coppola's forecast did include EWR to the extent it is already reflected in current data, and disputes that DTE established a sound basis for its own forecast of EWR. See Attorney General brief, pages 30-33. The Attorney General makes a similar argument regarding customer-

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[619] See 4 Tr 425.
[620] See 4 Tr 425.
[621] See 4 Tr 428.

owned generation. Regarding Mr. Leuker's revision of the Attorney General's forecast, the Attorney General argues: "From Mr. Leuker's rebuttal on page 6, lines 6-17, it can be seen that he extrapolated the usage per customer numbers for the projected test year in a different way than Mr. Coppola calculated in Exhibits AG-1.27 and AG-1.28. Therefore, it is not surprising that Mr. Leuker's "revised" results match closely to what he had originally forecasted."[622]

This PDF acknowledges that the Commission has expressed a preference for the use of regression analysis to project sales. While the Attorney General reasonably questions DTE's EWR and customer-owned generation assumptions, the difference in revenue requirement is relatively minor. This PFD recommends that the Commission adopt DTE's forecast, with an instruction to provide a thorough analysis of these assumptions in future cases.

2. Energy Bridge Program Fees

Through Mr. Isakson's testimony, Staff initially recommended a $1.622 million increase in test year revenue to reflect DTE's charges for energy bridge devices to allow customers to access real-time usage data from the AMI meters. Citing Mr. Cejas Goyanes's testimony, he explained that DTE began charging a $0.99 monthly fee, plus a $25 fee for lost or damaged devices, in April 2018, but increased the monthly fee to $1.99 as of May 2019. In rebuttal, Mr. Cejas Goyanes identified an error in Staff's calculation, which Staff acknowledged in its brief. Staff now recommends that test year miscellaneous

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[622] See Attorney General brief, pages 34-35.

revenue be increased by $525,685 to incorporate the energy bridge fees. DTE appears to agree. Thus, this PFD considers this issue resolved.

3. LIA, RIA Customer Counts

Mr. Isakson also addressed RIA and LIA customer counts and the associated projected test year revenue impacts. He explained that RIA enrollments have never reached the 60,000 level DTE is projecting, and noted a recent drop in enrollment:

> In September 2018 the number of enrollees dropped to a mere 954. Staff expects that this drastic reduction in RIA customer count is due to on-going difficulties with the Company's new billing system. Staff does not anticipate test year RIA customer count to mimic 2018 but cannot ignore its occurrence. According to the data it is not reasonable to assume an increase in RIA customer count. Therefore, Staff recommends a RIA customer count equal to the 5-year historic average enrollment.[623]

Mr. Isakson testified that using the five-year average monthly enrollment of 37,367 increases the revenue at present rates by $2.04 million.

Also addressing the LIA enrollment, he indicated that enrollment levels are near the program cap of 32,000 per month, and as discussed below, recommended that the cap remain:

> The Company did not show that more customers need the LIA credit than in previous test years. In addition, as this program is still a pilot and the Company is unable to show how successful this program is relative to the RIA, the cap should remain as it is.[624]

After taking issue with the reference in Ms. Johnson's testimony to the Commission approving "funding" for the Low Income Self-Sufficiency Program, noting that the Commission does not establish a fund but sets rates sufficient to provide for the projected

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[623] See 9 Tr 3117-3118.
[624] See 9 Tr 3118.

credits, Mr. Isakson testified that leaving the current enrollment cap in place as Staff recommends increases revenues at present rates by $8.64 million.[625]

In rebuttal, Ms. Johnson agreed that the drop in RIA enrollments reflected problems with DTE's billing system, and that enrollments are now at the level of 43,000, and can be expected to trend upward to the projected 60,000 level.[626] Regarding the LIA program, she testified:

> The Company recognizes that the LIA pilot yields the best success for eligible low income customers when pairing the LIA credit with the LSP program. The Company has presented this analysis to the Commission year over year. In addition, the Company does not believe that LIA and RIA credits are relative in how they assist customers as stated by Staff. The differences in the credit amounts of $40 and $7.50 indicate that their roles in assisting low income customers are not the same. The Company proposes that if the cap were raised from 32,000 to the 50,000 as requested, there would be no shortage of Non-LSP low income customers enrolled in receiving the credit.

This PDF finds that the most recent data on RIA enrollments should be used, i.e. 43,000. Regarding LIA enrollments, since several parties weighed in on the appropriate design of the company's low-income programs, issues regarding the LIA credit and the low-income pilot are discussed further in Section IX below. For the test year revenue calculation, consistent with that discussion, this PFD recommends retaining the 32,000 customer cap for the LIA program and adopting Staff's revenue adjustment.

4. Fuel and Purchased Power Revenue and Expense

Ms. Holmes testified that DTE is not proposing any change to the base PSCR factor set in Case No. U-15244 of 31.26 mills per kWh, but is proposing to change the

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[625] See 9 Tr 3119.
[626] See 6 Tr 1153-1154.

loss factor to 7.3%, which will increase the base PSCR factor at the sales level to 33.54 mills per kWh. She explained that the calculation of the 7.3% loss factor is taken from Mr. Leuker's projected net system output relative to sales. She also testified that DTE's rate calculations assume that all PSCR costs will be recovered.[627]

Staff adjusted both PSCR revenue and PSCR expense to reflect historical loss percentages, as explained by Ms. Shi in her testimony.[628] She expressed a concern that DTE relied on a projected loss factor without a supporting updated line loss study to determine whether the result is reasonable. Staff recommended instead that the Commission use a five-year average of historical sales and net system output to calculate a loss factor for PSCR revenue and expense, as shown in Exhibit S-7.0, with the supporting date in Schedule E2 of Exhibit A-15 and Exhibit S-7.1.[629] The result is a reduction in PSCR expense and offsetting revenues of $789,774.

The MEC Coalition recommends that the Commission reject any increase in the PSCR loss factor. Mr. Jester explained that DTE had not conducted an actual loss study since the 1990s:

> Exhibit MEC-59 (DJ-2) consists of a discovery response from DTE Electric which represents that in calculations of load at generation to serve load at system outlet, witness A. E. Brasil used loss factors based on a 1995 loss study, about which little information is available.
>
> Exhibit MEC-60 (DJ-3) consists of a discovery response from DTE Electric with an attached copy of DTE Electric's most recent line loss study, which DTE Electric identifies as "U-20561 MECNRDCSCDE-1.8b Line Loss Study 1999". It is unclear whether that loss study is the basis for DTE Electric's other loss estimates in this case.[630]

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[627] See 8 Tr 2252-2253.
[628] See Staff brief, pages 65, 68.
[629] See 9 Tr 3348.
[630] See 9 Tr 3803.

Labeling these outdated and unreliable, and further identifying changes in the intervening years that could have affected line losses, he recommended that the Commission reject DTE's proposal to increase the line loss factor used in calculation PSCR costs by more than 7%, from 6.8% to 7.3%.[631] Mr. Jester also recommended that the Commission require DTE to prepare and file a new engineering loss study:

> Since such a loss study will potentially be of value in a number of cases that might be considered before DTE Electric's next rate case, the Commission should order that study to be completed by a date certain and filed in the docket for this case, rather than order it to be included in DTE Electric's next rate case.[632]

Staff also recommends that the Commission require DTE to conduct a new line loss study before its next electric case.[633]

In rebuttal, Ms. Holmes objected to the characterization of DTE's loss factor as outdated, testifying that because the 7.3% reflects the difference between net system output and sales from Mr. Leuker's forecast, it is not outdated.[634]

This PFD recommends that the Commission adopt the MEC Coalition's recommendation and retain the current loss factor for PSCR purposes. As discussed below, this PFD also recommends that the Commission adopt Staff and MEC Coalition recommendations requiring DTE to conduct a new line loss study. Since the value will be revisited shortly, based on a study, it seems unnecessary to plan to change it twice, with potential confusion for the PSCR process. Assuming the loss factor is not changed, there should be no needed adjustment to current revenues.

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[631] See 9 Tr 3804-3806.
[632] See 9 Tr 3806-3807.
[633] See Gottschalk, 9 Tr 3251; also see Krause, 9 Tr 3390-3391.
[634] See 8 Tr 2262-2263.

B. Operations and Maintenance Expense

In its application, DTE projected a total O&M expense of $1,353,445,000, excluding depreciation and amortization and taxes, but subsequently reduced its projection to $1,352,930,000. Staff's revenue requirement recommendation in its reply brief is based on an O&M expense level of $1,292,979,000. The Attorney General recommended a $129 million reduction. The MEC Coalition took issue with certain expenses, but did not calculate a projected total O&M expense.

1. Inflation

In its May 2, 2019 order in Case No. U-20162, the Commission addressed the appropriate rate of inflation, again rejecting DTE's proposed blended inflation rate:

> The Commission agrees with the ALJ that DTE Electric has not presented sufficient evidence in this case to induce the Commission to depart from its decisions in the 2018 orders and previous rate cases rejecting a blended inflation rate. The Commission agrees with the Staff that while DTE Electric will see some inflation, the company will also offset some of the inflation with productivity gains. Therefore, the Commission finds the Staff's proposed inflation rates to be the most reasonable and adopts the findings and recommendations of the ALJ.[635]

In its application in this case, DTE again proposes to use a blended rate of inflation, basing its projections on a 3% wage rate inflation factor for internal and contract labor and a Consumer Price Index (CPI) forecast for non-labor costs. Ms. Uzenski presented DTE's projected inflation factors in Schedule C5.15 of Exhibit A-13, using a blend of DTE's forecast labor inflation of 3%, which Mr. Cooper discussed in his testimony, and a

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[635] See May 2, 2019 order, page 73.

projected CPI-Urban value.[636] The resulting rates are 2.8% for 2019, 2.9% for 2020, and 2.9% for 2021 (prorated to 0.97% for the first four months of the year.)

Staff recommended the following inflation factors, presented by Mr. Ufollo: 2.19%, 2.477%, and 2.50% for 2019 through 2021 respectively. Mr. Ufollo presented a comparison of DTE's proposed inflation rates with Staff's proposed rates in Chart 3 at 9 Tr 3322. He testified that Staff used an average of projected inflation rates from IHS Global Insight, the International Monetary Fund, and the Energy Information Administration as shown in Exhibit S-4, Schedule D-3a.[637] In its brief, Staff explained that it adjusted DTE's projected O&M expenses for steam generation, fuel supply & MERC fuel handing, nuclear, hydro, and other power generation to reflect its inflation factors as shown in Exhibit S-7.3, but also recommends that its inflation factors be used to project distribution, customer service, regulated marketing and corporate support.[638] The revision increases Staff's recommended inflation adjustment from $5.5 million to $11.3 million.

ABATE argues that the Commission should reduce DTE's O&M inflationary expense projections by $17.52 million.[639] Ms. York also objected to DTE's use of a 3% wage escalation factor as part of its composite inflation projection, testifying that DTE reiterated the same arguments the Commission rejected in prior cases.[640] She also testified that DTE had not provided specific evidence on its contractual obligation to

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[636] See 6 Tr 1507-1508.
[637] See 9 Tr 3321-3322.
[638] See Staff brief, pages 68-70.
[639] See ABATE brief, pages 18-19.
[640] See 7 Tr 1923.

increase wages in the test year.[641] Recommending that the projected CPI be used for inflationary projections, she testified that this adjustment results in a $17.52 million reduction to DTE's projected O&M expenses, as shown in Exhibit AB-7.[642] She also noted that despite historical efforts to control its O&M costs, DTE is not projecting any specific savings offsets in this case, although it acknowledges cost-control efforts and capital investments expected to produce O&M cost savings.[643] In its brief, ABATE argued that the Commission should adopt Ms. York's recommendation and exclude the 3% wage escalation factor.[644] ABATE also cites Ms. Crozier's testimony/discovery response in Exhibit AB-8 acknowledging DTE's ongoing cost containment efforts, and emphasizes that DTE is expecting cost reductions as a result of distribution capital expenditures, generating plant closures, and the transition to alternative sources of generation. ABATE also argues that DTE will reduce costs as higher-cost workers retire and are replaced with lower-cost workers. ABATE argues the Commission should limit inflationary projections to the CPI forecasts presented by Ms. York, based on Blue Chip Economic Indicators, 1.8% for 2019, and 2.1% for 2020 and 2021.

The Attorney General argues that the Commission should exclude all inflationary increases DTE projects for O&M spending, or in the alternative, limit increases to the projected CPI-Urban increases.[645] Mr. Coppola identified $69.8 million attributable to DTE's projected inflationary increases in O&M spending. After noting DTE's use of a

[641] See 7 Tr 1924.
[642] See 7 Tr 1926.
[643] See 7 Tr 1926-1928.
[644] See ABATE brief, page 18.
[645] See Attorney General brief, pages 35-39.

blended rate that has been rejected by the Commission, he testified to the same concern with the use of an inflation factor that he identified in connection with certain of DTE's capital expense projections:

> More importantly, and contradicting some of the Company's testimony in this case, DTEE has not experienced across-the-board inflation pressure on its operating costs. In fact, according to Company witness Michael Cooper, actual O&M costs have remained well below the inflation trend line from 2009 to 2018. It is therefore difficult to understand why the Company would project inflation-related cost increases for 2019, 2020, and the four months in 2021.
>
> The Company has also been very vocal in stating that investments in technology will result in the reduction of O&M expenses. Yet, customers now must pay higher rates due to forecasted increases in O&M costs. The Company has not provided any evidence that its operations are facing inflationary cost pressures that it cannot manage in the course of operating its business. It is more than likely, based on historical data, that the proposed $69.8 million in inflation cost increases will not happen. The Company will likely continue to manage its operations to offset the low level of forecasted inflation with increased operating efficiencies and cost cutting.[646]

Acknowledging that the Commission has allowed inflation cost increases for O&M expenses in prior cases, Mr. Coppola nonetheless recommended that the Commission reject DTE's projected inflationary increases:

> As a matter of policy, it is not advisable to allow utilities to escalate costs for forecasted future inflation. It becomes a self-fulfilling prophecy to increase future costs with inflation increases which then fuel and justify further inflationary trends. The Commission should only grant inflation cost increases when those increases are actually experienced and are likely to occur, and not because it has been past practice to do so. In this case, the evidence is clear that inflation cost increases are not warranted or necessary.[647]

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[646] See 9 Tr 3044-3045.
[647] See 9 Tr 3045-3046.

In support of his recommendations, he testified that O&M expenses for distribution operations and generation are currently below projected levels and below the proposed inflation adjustments. As an alternative, he recommended that the Commission reject DTE's proposed use of a separate wage inflation factor of 3%, and instead use the CPI-Urban index projections of 1.9%, 2.1%, and 1.8% for 2019 through 2021, as shown in Exhibit AG-1.30.[648]

In her brief, the Attorney General relies on Mr. Coppola's testimony in recommending disallowance of all projected inflationary increases, and also reviews the Commission's orders in Case Nos. U-18014, U-18255, and U-20162 to show that the alternative CPI-Urban inflation estimates presented by Mr. Coppola are more appropriate if the Commission chooses to adopt an inflation estimate.

Kroger recommends that inflation be removed from DTE's projected test year - non-labor O&M expenses.[649] Mr. Bieber testified to two concerns. First, he explained:

> [A]t a broad policy level, I have concerns about regulatory pricing formulations that reinforce inflation. This occurs when projections of inflation are built into formulas that are used to set administratively-determined prices, such as utility rates. Such pricing mechanisms help to make inflation a self-fulfilling prophecy. As a matter of public policy, this is a serious concern. It is one thing to adjust for inflation after the fact; it is another to help guarantee it. For this reason, I believe that regulators should use extreme caution before approving prices that contribute to inflation before it occurs.[650]

Additionally, he objected to creating what he characterized as a cost-cushion:

> 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

[648] See 9 Tr 3046-3047.
[649] See Kroger brief, pages 4-6.
[650] See 8 Tr 2163-2164.

> 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.[651]

Citing this testimony, Kroger argues that building in an inflation allowance becomes a self-fulfilling prophecy that creates a "cost cushion" for the utility. Kroger cites the Minutes of the Federal Open Market Committee for September 17-18, 2019, stating inflation estimates of 1.7%-1.8% for 2019, 1.9%-2.0% for 2020, and 2.0% for 2021. Kroger cites Exhibit KRO-1 to show that DTE's protected test year O&M expenses include $7.4 million for non-labor inflation, and $25.5 million for outside services inflation, contending these cost adders should be removed.

Given the Commission's longstanding reliance on inflation for projecting these categories of expenses, notwithstanding the indications that DTE will reap the benefits of increased efficiencies from capital expenditures, this PFD recommends that the Commission adopt the lower inflation rate recommended by the Attorney General based on projected CPI-Urban values of 1.9%, 2.1%, and 1.8% for 2019 through 2021. DTE's proposed labor inflation factor should be rejected because DTE has not presented any new information sufficient to reach a conclusion different from the one the Commission has reached in prior rate cases. Additionally, recognizing that in its evidentiary presentation in this case, DTE has been reticent, even remiss, in failing to provide savings estimates associated with capital expenditures, this PDF recommends that DTE be directed to evaluate its own productivity gains in the last decade or propose the use of a productivity index.

[651] See 8 Tr 2164.

2. Steam Power (Schedule C5, line 1; Schedule C5.1)

Mr. Coppola compared 2019 actual expenditures to September 2019 to 2018 historical expenditures. He testified that when this level of expense is annualized, the annualized amount is 11% below DTE's 2018 expenses for this category, as shown in Exhibit AG-1.13 and in a chart at 9 Tr 3054. Mr. Coppola used this deviation as support for his recommendation to exclude inflation projections from DTE's O&M expense projections as discussed above.[652]

a. St. Clair Unit 1

In addition to the inflation-related adjustment, the Attorney General also recommends a $3.1 million reduction to the projected expenditures for the St. Clair plant due to the retirement of St. Clair unit 1 in March of 2019.[653] Mr. Coppola acknowledged DTE's $1.4 million reduction to historical expenditures to address this retirement,[654] but citing Exhibit AG-1.35, contended that an additional adjustment was warranted. First, he noted a decline in O&M expenses for the St. Clair plant from 2017 to 2018 of $4.3 million, which he believes can be mostly attributed to the retirement of St. Clair unit 4. Second, he computed an average expense per unit for the plant of $7.3 million to show the potential cost savings. Third, he testified the generating capacity of the plant decreased following the retirement of unit 1 by 12.4%, which would equate to a $4.5 million reduction in costs.[655]

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[652] See 9 Tr 3055.
[653] See Attorney General brief, pages 43-45.
[654] See Morren, 5 Tr 632.
[655] See 9 Tr 3056-3057.

Mr. Morren testified in rebuttal that Mr. Coppola's analysis is faulty because it does not properly consider the offsetting impact of $8 million in "O&M insurance proceeds" in 2018. He explained that if one were to exclude those proceeds from 2018 expense levels, they would have been $8 million higher, i.e. they would have shown a $4 million increase rather than a decrease.[656] The Attorney General does not discuss Mr. Morren's rebuttal testimony in its brief,[657] and this PFD finds Mr. Morren's explanation of the data relied on by the Attorney General to be reasonable. Thus, this PFD finds that no reduction to the proposed O&M expenses for St. Clair unit 1 is appropriate.

b. River Rouge Unit 3

Consistent with the discussion in section V above, MEC recommends that the Commission exclude projected O&M expenses for River Rouge unit 3 that are inconsistent with operating the unit after May 2020.[658] As discussed above, this PFD concluded that DTE has failed to establish that its plan to operate River Rouge unit 3 beyond May 2020 is reasonable and prudent. DTE argues that in Case No. U-20162 the Commission provided O&M expense recovery. The MEC Coalition does not ask to have all O&M associated River Rouge unit 3 excluded, but only the amount inconsistent with its retirement. A review of Ms. Leslie's analysis in Schedule B6.2, page 3, shows incremental O&M expense of $1 million in 2020 and $3 million in 2021 associated with

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[656] See 5 Tr 639-641.
[657] See Attorney General brief, pages 44-45.
[658] See MEC brief, page 11.

continuing to operate the plant to 2022. Thus, an O&M expense reduction of $1.66 million is appropriate.[659]

3. Nuclear Power (Schedule C5, line 3; Schedule C5.3)

DTE's projected test year O&M expense reflected on Schedule C5.16 includes a projected expenditure of $1.6 million for a nuclear decommissioning cost study that DTE projects will be completed by May 2020.[660] Mr. Davis identified this projected expenditure in his testimony.[661] Ms. Alderson took issue with DTE's projected expenditures for this nuclear decommissioning study.[662] She acknowledged that DTE was directed to provide an updated decommissioning study in its next rate case or in a standalone proceeding. She objected to DTE's proposal to recover an estimated $1.6 million in nuclear decommissioning study expenses through a five-year amortization, testifying that DTE has not yet awarded contracts to complete the study. Ms. Alderson considers her recommended adjustment to be confidential. Mr. Davis also further addressed this in his rebuttal testimony.

In its brief, ABATE cites Ms. Alderson's testimony, and recommends that any funding be limited to payments to outside vendors.[663] ABATE does not address Mr. Dennis's rebuttal testimony. This PFD finds that it is reasonable to include DTE's projected study expenses in its test year O&M expense. No party questioned the

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[659] $1 million (times 2/3 for the first 8 months of the projected test year) and $3 million (times 1/3 for the last 4 months of the projected test year. While the MEC Coalition established cost elements missing from DTE's NPVRR analysis, it did not establish the missing elements are included in DTE's rate case projections.
[660] See Exhibit A-13, Schedule C5.16, line 23.
[661] See 9 Tr 3459-3460.
[662] See 7 Tr 1812-1813
[663] ABATE brief, pages 16-17.

legitimacy of the undertaking, and the time frame for completion of the study is clearly realistic due to the Commission's prior order and DTE's commitment to make the required filing.

4. Distribution (Schedule C5, line 6; Schedule C5.6)

Mr. Bruzzano and Ms. Rivard both testified in support of DTE's projected distribution system O&M expense. DTE's tree-trimming program is discussed in greater detail in the discussion of surge funding in section IX below. Staff supported DTE's request, subject to Staff's use of revised inflation factors as explained in its initial brief.[664]

As noted above, the Attorney General recommended that the Commission exclude DTE's projected inflationary increase for distribution O&M expenses, which accounts for $21.3 million of the $69.8 million inflation-related adjustment. In addition, the Attorney General recommended that projected test year distribution O&M expenses be reduced by $5.1 million to exclude inflation from the normalization adjustment, and by $2.8 million to exclude DTE's requested $2.8 million increase in tree trimming expenses. Regarding DTE's normalization adjustment, this PFD finds that a normalization adjustment is acceptable for the same reasons discussed in connection with emergent capital costs in section IV above.

Regarding the tree trimming expenses, Mr. Coppola considered that the Commission set the base level for tree trimming expenses for 2020 at $95.1 million in Case No. U-20162. In her rebuttal testimony, Ms. Rivard objected to Mr. Coppola's recommendation as ignoring DTE's projected 3% inflation rate. The Attorney General

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[664] See Staff brief, pages 81-83; Evans 9 Tr 3231.

addressed this rebuttal testimony in her brief, contending that DTE also asserted a 3% inflation rate in Case No. U-20162 to provide a long-term forecast of tree trimming expenses through 2025, and the Commission did not adopt that inflation rate.[665]

Mr. Bruzzano testified in rebuttal at 4 Tr 266, objecting to the proposed exclusion of inflation, and also citing Mr. Cooper's and Ms. Uzenski's direct testimony regarding inflation.[666] He also objected to updating DTE's inflation factors, testifying:

> [T]he Company's projected distribution expenditures, both capital and O&M, were developed at a point in time. Selectively choosing cost elements that have decreased since that point in time without acknowledging those items that may have increased over the same period would not be appropriate.[667]

This PFD does not read the Commission's May 2, 2019 order in Case No. U-20162 as setting funding levels for the surge program based on a static level of O&M tree trimming expense. On this basis, this PFD finds DTE's proposed increase is reasonable.[668]

5. Customer Service (Schedule C5, line 7; Schedule C5.7)

a. Merchant Fees

In Case No. U-20162, the Commission approved DTE's decision to eliminate the option for larger industrial and commercial customers to pay by credit card at no additional charge:

> The Commission agrees with DTE Electric's proposed change to eliminate the option to pay by credit card for larger commercial and industrial customers, while preserving the option for residential and smaller commercial customers. The Commission agrees with the ALJ that merchant fees for residential and smaller commercial customers are a reasonable O&M expense. The Commission recognizes the increasing popularity of paying by credit card and the added convenience for the customer.

[665] See Attorney General brief, page 42.
[666] See 4 Tr 266-268.
[667] See 4 Tr 268.
[668] See May 2, 2019 order, pages 74-80; Exhibit A-22, Schedule L1.

> Therefore, the Commission adopts the $2.6 million increase for merchant fees and the change in DTE Electric's current payment options to eliminate the credit card payment option for larger commercial and industrial customers on rate schedules D6.2, D8, D11, and secondary choice customers. The Commission directs DTE Electric in its next rate case filing to provide information on the reduction in uncollectibles attributable to credit card payments.[669]

DTE now proposes to further revise its fee policy for credit card transactions.

Ms. Uzenski identified increased merchant fees as one of the primary reasons DTE projects O&M expense increases for the projected test year.[670] Mr. Clinton presented testimony in support of DTE's projected merchant fee expenses.[671] He testified that DTE has been experiencing a continued increase in merchant fee expense over the past several years, and explained that DTE's projected $19.1 million test year expense projection is based on a compound annual increase of 17.5% for residential customers and 51.4% for non-residential customers. Mr. Clinton also stated that customers often rely on debit or credit card payments to secure continuity of service. He explained that to reduce projected test year expense, DTE now proposes to preclude commercial and industrial customers from using credit cards for bill payments if their total bill in the preceding calendar year was more than $75,000:

> The Company believes it is reasonable to expect these larger, more sophisticated commercial and industrial customers to use more common business to business forms of payment, such as a check or electronic bank payment, that result in significantly lower costs to the Company and correspondingly to its customers.[672]

He testified that this change is expected to save $4.7 million in the projected test year.

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[669] See May 2, 2019 order, page 85.
[670] See 6 Tr 1508.
[671] See 6 Tr 1008-1010.
[672] See 6 Tr 1010.

Mr. Coppola did not object to the revised policy, and recommended that projected costs be reduced by the company's projected $4.7 million savings associated with the change.[673]

Staff recommends a further restriction on the availability of no-fee credit card payment options and reliance on historical costs for the projected test year.[674] Ms. McMillan-Sepkoski testified that Staff is concerned about the rising costs of this program, testifying that in 2018, the average merchant fee DTE paid per residential customer transaction was $0.92, while the average merchant fee DTE paid per non-residential customer transaction was $7.12.[675] Staff also addressed the study Ms. Johnson presented:

> Company witness T.D. Johnson testifies (at page 13, lines 8 through 11) that the Company did a five (5) month study on customers entering final arrears. When asked again about this in Staff Exhibit S-3.9[sic],[676] the Company indicates that uncollectibles did not decrease, but in fact could have possibly been an increase in uncollectibles if those customers had not paid with a credit/debit card. Staff is not convinced that a five (5) month study is adequate for what the Commission expected with good reason to receive.[677]

And Ms. McMillan-Sepkoski identified an audit concern with the merchant fees DTE reports for 2018:

> Another concern is when the Company was asked to reconcile a master pricing schedule for 2018 to the historical test year, the Company respondent stated per Staff Exhibit S-3.10[sic][678] they are unable to reconcile the 2018 actual merchant fee expenses to the master pricing schedule.

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[673] See 9 Tr 3057-3058.
[674] See Staff brief, pages 72-73.
[675] See 9 Tr 3283, Exhibits S-8.7, and S-8.8.
[676] Exhibit reference clearly intended to be Exhibit S-8.9.
[677] See 9 Tr 3284.
[678] Exhibit reference clearly intended to be Exhibit S-8.10.

A review of Exhibit S-8.10 shows that the "master pricing schedule" at issue is the master pricing schedule incorporated in DTE's Merchant Services Master Services Agreement. DTE's answer to Staff's audit request stated in full:

> DTE Electric is unable to reconcile the 2018 actual merchant fee expense to the master pricing schedule. The primary reason is that interchange costs, which is the vast majority of the merchant fee expenses, are not completely covered by the contract. The contract only addresses interchange fees that qualify for the low "utility rate". Transactions which do not qualify for the low "utility rate" are charged at more costly rates per the contract.[679]

Ms. McMillan-Sepkoski recommended that only residential customers be eligible for the free credit card payment option, and that projected test year costs be limited to the historical amount of $8,399,000.

In rebuttal, Mr. Clinton took issue with Staff's and the Attorney General's recommendations. Mr. Clinton testified that DTE has been accepting debit and credit card payments since 2010, and recovered the costs through rates.[680] He disagreed with Ms. McMillan-Sepkoski's recommendation to further limit the availability of free credit card payments, contending:

> Disallowing the use of debit and credit cards for the 34,000 smaller commercial and industrial customers utilizing them in 2018 would negatively impact customer satisfaction. It would require customers to change their payment methodology which could be a reoccurring, web and/or mobile payment channel and would most likely drive increased call center volume inquiring about the change. [681]

He testified that flexible payment methods "assist customers in paying their final arrears bill to reestablish service or eliminate service disconnections," and cited Ms. Johnson's

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[679] See Exhibit S-8.10.
[680] See 6 Tr 1048.
[681] See 6 Tr 1048.

five-month study, noting that the $1.9 million could equate to $4.6 million on an annualized basis. Regarding the $4.7 million in savings associated with DTE's proposal, he testified that only a $2 million reduction should be made for the projected test year, because DTE would not implement its revision until January 1, 2021 "as the Company would require time to implement both the required technology changes and to effectively manage the customer experience through this transition if a ruling came as late as May 2020."[682]

Mr. Clinton also took issue with Mr. Coppola's statement attributing the increase in credit and debit card use to DTE advertising it as a cost-free option. He contended instead: "The growth of credit and debit card transactional payments follows national trends which as reported by the Federal Reserve have an annual compound growth rate of over 7.2% from 2012 to 2016."[683] As the Attorney General argues, DTE did clearly represent to customers that the credit-card payment service was available at no charge.

In its brief, Staff responded that it understands DTE's concerns to avoid negatively impacting customer satisfaction, but believes residential customers would not be happy paying higher costs for the non-residential class. Staff also characterizes DTE's study as not showing a drop in uncollectibles resulting from the credit card merchant fee payments.[684]

The Attorney General addressed Mr. Clinton's rebuttal testimony in her brief, arguing that he failed to support his claim that test year savings should only be $2 million, due to a lag in the company's ability to implement the change, rather than the $4.7 million

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[682] See 6 Tr 1049.
[683] See 6 Tr 1047.
[684] See Staff's brief, pages 72-73.

savings presented in his initial testimony.[685] Citing Exhibit AG-1.50, the Attorney General argues that DTE's explanation of the lag is limited to an assertion that its billing system is complex. She also cites Mr. Clinton's testimony on cross-examination,[686] acknowledging that DTE has not analyzed the time it would take to implement the changes. The Attorney General also argues that DTE could have implemented the changes without waiting for Commission approval.

In its brief, DTE relies on Mr. Clinton's rebuttal testimony. In its reply brief, it responded to the Attorney General's assertion that DTE could self-implement the change: "The Company is unwilling to proceed in this manner, and notes that the AG did not suggest a basis for her proposed departure from regulatory practice."[687]

This PFD finds that it is reasonable to accept Staff's recommendation and adjustment, with the caveat that DTE should be able to accept credit card payments from C&I customers as it proposes, as long as it charges a fee for the service.

b. IT Expenses

Consistent with its recommended exclusion of the capital costs associated with certain IT programs, Staff recommended that the projected O&M expenses for those projects be excluded form test year O&M expense projections.[688] As Ms. Wang testified, Staff reduced projected test year O&M expense by $575,252 based on the reported O&M expenditures associated with the bill redesign project in DTE's business case, and Staff reduced projected test year O&M expense by $600,000 based on the reported O&M

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[685] See Attorney General brief, pages 45-47.
[686] See 6 Tr 1101.
[687] See DTE reply, pages 74-75.
[688] See Staff brief, pages 71-72.

expenditures associated with the Network -Advanced Metering Infrastructure Enhanced Support.

In rebuttal, Ms. Uzenski asserted that these expenses were not included in DTE's projected revenue deficiency calculations:

> The projected O&M submitted by the Company uses 2018 historical expense and adjusts for inflation and other specific projection adjustments detailed in our Exhibits A-13, Schedules C5. Since these amounts were clearly not included in the Company's projection adjustments, the Commission should not include these disallowances.[689]

In its brief, Staff responds that the O&M costs are clearly stated in DTE's business case for these programs, and reasons that if the capital costs are disallowed as Staff recommends, it is only reasonable to disallow the O&M costs as well. This PFD finds that Staff's recommendation is reasonable and consistent with the capital expense adjustment. Clearly, DTE anticipated that the money it planned to spend on the bill redesign project would be covered by its O&M expense request.

6. Uncollectible Accounts Expense (Schedule C5, line 8; Schedule C5.8)

In Case No. U-20162, the Commission addressed the method used to project uncollectible accounts expense, rejecting DTE's use of a three-year average of actual uncollectibles in favor of Staff's use of the three-year average of the ratio of net charge offs to revenue, referred to as the "cash basis" method:

> The Commission agrees with the ALJ that the cash basis methodology has been approved in previous cases and that consistency of method is important. The Commission finds the Staff's cash basis method to be the most accurate and least prone to potential forecasting error. Therefore, the Commission adopts the findings and recommendations of the ALJ.[690]

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[689] See 6 Tr 1561-1562.
[690] See May 2,2019 order, page 87.

The Commission's order indicated this method had been used in Case Nos. U-14347, U-16191, U-16794, U-17735, and U-17790.

Ms. Johnson testified in support of DTE's projected $51.6 million uncollectible accounts expense projection as shown in Schedule C5.8 of Exhibit A-13. She explained how DTE uses a balance sheet method to determine the accounts receivable reserve for uncollectible accounts:

> The AR reserve is calculated by applying reserve factors to aged receivables. Customer accounts receivable are classified in 30-day increments (arrears buckets) and a reserve factor is applied to each 30-day increment. The sum of these reserve values represents the total AR reserve.
>
> The reserve factors are recalculated monthly using a rolling average of the ratio of historical write-offs to historical arrears within each arrears bucket (30, 60, 90, etc.). A 12-month rolling average is utilized for residential and small commercial accounts and a 60-month rolling average is utilized for large commercial and industrial accounts.[691]

She testified that DTE determines its uncollectibles expense from a review of the accounts receivable, recording uncollectible expense in the income statement to reflect the change in the AR reserve:

> This is calculated as the required increase/decrease in the AR reserve based on the aging analysis just described, plus accounts that were written off that month, minus accounts that were recovered (on previously written off accounts) that month, plus any DTE Electric matches of low-income funding received.[692]

For its test year projection in this case, Ms. Johnson testified that DTE used a three-year average of "actual uncollectible expense" for 2015 through 2017, further testifying that

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[691] See 6 Tr 1143.
[692] See 6 Tr 1143.

this amount reflects DTE's efforts to keep uncollectible expense from increasing despite continuing economic challenges for many of its customers.[693] She explained that DTE excluded 2018 from its calculations due to system issues:

> [U]ncollectible expense was abnormally high during 2018 due to system issues and delayed collections, resulting from the Customer 360 (C360) billing system implementation. This type of project occurs perhaps once in 10 to 15 years and had a significant impact on collection activities. The impact of those issues is not easily quantified. Therefore, the Company excluded 2018 uncollectible expense from the calculation.[694]

In her testimony, Ms. Johnson acknowledged that the Commission adopted Staff's cash basis method for uncollectible expense in Case No. U-20162, and acknowledged that the Commission found Staff's method to be the most accurate and least prone to potential forecasting error. Nonetheless, she testified:

> DTE Electric believes the Company's three-year average method is the least prone to error because it is a straight forward and an easily verifiable calculation, using figures from the Company's books. The Staff's method, approved in Case No. U-20162, has an inherent flaw. Staff's calculation applied historical write-off percentages to the Company's forecasted revenues; however, those revenues did not include rate relief. Since the incorrect revenues were used as the basis for the calculation, the uncollectible expense was understated. In order for Staff's method to work properly, the write-off percentages must be applied to the finalized revenue inherent in the authorized revenue requirement. The Company applied a calculation based on a historical average because it provides a more consistent view of economic events.[695]

After describing efforts underway at DTE to reduce uncollectible expense,[696] Ms. Johnson addressed the study DTE was directed to undertake in Case No. U-20162 to evaluate the

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[693] See 6 Tr 1144; 1146-1147.
[694] See 6 Tr 1144.
[695] See 6 Tr 1145.
[696] See 6 Tr 1146-1147.

effect of the company's no-cost credit card payment option on uncollectible expense. She testified:

> We analyzed a 5-month period of payment methods from September 2018 to January 2019 for customers once they entered final arrears. Results were that approximately $1.9 million of payments went from non-credit card to credit card method of payment.[697]

Ms. McMillan-Sepkoski testified that DTE's projected uncollectible accounts expense is based on the accrual method, while Staff continues to recommend the cash basis method. She testified that using this method produces an uncollectible accounts expense of $46.8 million, a reduction of $4,792,261.[698] She testified that Staff believes the cash basis method is a better approach that provides a reasonable estimate and mitigates the potential for forecasting error.

In his testimony in this case, Mr. Coppola recommended a $2.1 million reduction to DTE's projected uncollectible accounts expense, citing the study DTE performed in response to the Commission's order in Case No. U-20162 to determine whether the company's elimination of credit card fees has had an impact on uncollectible expense.[699] Citing his calculations in Exhibit AG-1.38, he testified that annualizing the estimated savings of $1.9 million for the five-month-study period results in annual savings of $4.6 million; he further adjusted the savings to reflect the increased use of credit cards DTE projects in this case, resulting in an annual projected test year savings of $6.7 million. His recommended $2.1 million reduction in test year uncollectible expense is the

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[697] See 6 Tr 1148.
[698] See 9 Tr 3276-3277. Ms. McMillan-Sepkoski also noted that the adjusted as reflected in Schedule C5 of Exhibit S-3 and Schedule A1 of Exhibit S-1 incorporate a figure that is overstated by $7,581.
[699] See 9 Tr 3058-3059.

difference between the 2018 annualized savings amount of $4.6 million and the projected test year savings amount of $6.7 million, as shown in Exhibit AG-1.38.

In her rebuttal testimony, Ms. Johnson repeated the explanation she provided in her direct testimony regarding the cash basis method the Commission adopted in Case No. U-20162. She also objected to Mr. Coppola's recommended $2.1 million reduction based on DTE's study, contending that the impact of the proposed reduction is already embedded in the historical values used in DTE's projections, and contending that the projected increase in merchant fees reflects an increase in all customers using the payment option "and not specifically related to customers who may be disconnected."[700]

Ms. Uzenski also addressed Staff's uncollectible expense projection in her rebuttal testimony, testifying that she "does not agree with the cash basis method for estimating uncollectible expense," and further contending that the method Staff used in this case is not consistent with the method approved in Case No. U-20162:

> Although I disagree with using a cash basis method, if it is used, then it should be applied consistently. The technical corrections needed to ensure Staff's proposal is consistent with the U-20162 Order are shown on my Exhibit A-40, Schedule EE1. On line 1 and line 2, Total Write-Offs and Collections should be used from the P 522, page 226A. On Line 4, Sales to Ultimate Customers should be used from the P-222 page 300. With these changes, the three- year average of net write-offs to revenue changes to 1.0738% on Line 7. One additional technical correction is to use the Projected Revenue from Staff Exhibit S-3, Schedule C1, on Line 6 which is also consistent with the approach in Case No. U-20162.

She testified that the result of her revisions in Schedule EE1 of Exhibit A-40 is to increase the uncollectibles expense projection to $52.4 million.

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[700] See 6 Tr 1152-1153.

In her brief, the Attorney General defended Mr. Coppola's adjustment in response to Ms. Johnson's rebuttal testimony.[701] The Attorney General noted that on cross-examination, Ms. Johnson was unable to state where Mr. Coppola claimed this was a new offering,[702] arguing that Mr. Coppola's adjustment was based on projected new credit card users. Reviewing the mechanics of Mr. Coppola's adjustment, the Attorney General argued that Mr. Coppola considered only residential customer usage and residential customer savings in his adjustment. Responding to Ms. Johnson's claim that a projected increase in customers using the credit card option is not equivalent to customers who may be disconnected, the Attorney General argues that it is "logical to assume, as Mr. Coppola shows, that if more payments are made by credit card, then, proportionally, the same impact on uncollectible expense that Ms. Johnson calculated in her study will hold."[703]

In its brief, Staff adopted the revisions to the cash basis method in Schedule EE1 of Exhibit A-40 and revised its uncollectible expense projection to $52.4 million.[704]

This PFD first finds that neither Staff nor DTE properly implemented the cash basis method for estimating this expense item because they failed to update the data,[705] or show that the problem with DTE's three-year average method also affects the cash basis method. In theory, the cash basis method, which looks at net write-offs to total revenue

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[701] See Attorney General brief, pages 47-50.
[702] See 6 Tr 1165.
[703] See Attorney General brief, page 50.
[704] See Staff brief, pages 73-74.
[705] This is most clear from Ms. Uzenski's Exhibit A-40, in which she used the exact same percentages, taken from the exact same years (2015-2017) as was used in Case No. U-20162. While Staff clearly made an error in its original analysis, Ms. Uzenski's use of the stale data with no further analysis was not a serious effort to comply with the Commission's prior order.

would not be affected by a billing system problem. Note, too, that DTE's actual 2018 operating revenues were approximately $100 million above weather normalized values, so on an absolute basis, it is not surprising 2018 uncollectible expense would be higher than the prior three-year average. Again, this is an argument for the cash basis method the Commission has adopted. In the absence of evidence that an updated application of the cash basis method would produce an unreasonable result, this PFD finds that it is reasonable to adopt Mr. Coppola's recommendation, including his $2.1 million adjustment, which reasonably attempts to apply the result of DTE's study. A proper application of a three-year average would ordinarily make such adjustments unnecessary, because the average will incorporate savings over time.

7. Regulated Marketing (Schedule C5, line 9; Schedule C5.9)

a. Plug-in Vehicle Costs

DTE's filing included a projected test year amortization expense of $1.2 million for plug-in vehicle costs under the authorization of the Commission's December 11, 2015 order in case No. U-17767, as shown in Schedule C5.9 of Exhibit A-13. Staff recommends a reduction of $347,000 in the amortization expense.[706] Mr. Welke explained Staff's adjustment. He testified that DTE would complete the authorized amortization on January 20, 2021, prior to the conclusion of the test year. To include only the appropriate remaining amortization, he reduced DTE's projected test year amortization expense by $347,000, as shown on Schedule C5.3 of Exhibit S-3.[707] In

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[706] See Staff brief, pages 79-80.
[707] See 9 Tr 3339.

rebuttal, Ms. Uzenski agreed that DTE had overstated the amortization amount for the test year, but testified that the correct adjustment should be $415,000, which she calculated using an end date of January 1, 2021 rather than the January 20 date underlying Staff's calculation.[708]

In its brief, Staff stated that it stands by its initial adjustment, however, in its reply brief, Staff adopted DTE's revision to reduce disputed issues.[709] DTE cites Ms. Uzenski's rebuttal testimony. While the amount of the difference between the estimates is small, this PFD finds that it is appropriate to give the ratepayers the benefit of any doubt, and DTE's adjustment should be adopted.

b. Charging Forward Costs

DTE's filing included an amortization expense of $628,000 as shown in Schedules C5.9 and C5.9.1 of Exhibit A-13. Staff recommended a reduction of $360,000 in the test year amortization expense for the Charging Forward program.[710] Mr. Welke testified that DTE's projected amortization expense includes the amortization of projected expenditures, not yet incurred, which is inconsistent with the approval granted in Case No. U-20162. He explained that DTE's amortization expense includes projected expenditures of $2 million in 2019 and $3.4 million in 2020, while DTE only spent $220,000 through September 2019.[711] He recommended that only the $220,000 in reviewed expenditures be amortized for recovery in the projected test year.

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[708] See 6 Tr 1574.
[709] See Staff brief, pages 79-80; see Staff reply brief, pages 6-7.
[710] See Staff brief, pages 80-81.
[711] See 9 Tr 3339.

While as discussed above, DTE seeks to earn a return on the unreviewed and projected balance, DTE agrees with Staff that the amortization should be limited to actual, reviewed expenditures. In rebuttal, Ms. Uzenski testified that she “understand[s] that amortization of the regulatory asset for rate-making purposes can include only those amounts audited by Staff.”[712] Ms. Uzenski’s further rebuttal testimony regarding the inclusion of unamortized balances in working capital was addressed above in section V.B.

Consistent with that discussion, this PFD finds that Staff’s adjustment to the amortization expense should be adopted. As Mr. Welke explained, Staff did not include this adjustment in Staff’s revenue requirement calculation in Exhibit S-1, but includes the adjustment in the calculations accompanying its brief.

Recommended modifications to the charging forward program are discussed below.

c. Fixed Bill Pilot

DTE’s projected O&M expense also includes $900,000 for the fixed bill pilot.[713] As discussed in the rate design section below, because this PFD recommends that the pilot be rejected, it recommends that funding for the pilot also be excluded from test year O&M expense projections.

d. Low Income Renewable Energy Pilot

DTE’s projected O&M expense also includes $800,000 for its low-income renewables pilot program.[714] Because this PDF does not recommend approval of the

[712] See 6 Tr 1575.
[713] See Clinton, 6 Tr 1034-1035, 1037, 1040, 1067.
[714] See 6 Tr 1040.

pilot, for the reasons stated in the rate design section below, this PDF recommends that the associated expenses be excluded from test year O&M expense projections.

8. Corporate Support (Schedule C5, line 10; Schedule C5.10)

a. Injuries and Damages

In Case No. U-20162, the Commission retained a five-year average method for projecting this expense category, not adjusted for inflation.[715]

Ms. McMillan-Sepkoski presented Staff's recommended projection for injuries and damages expense. She testified that DTE's projected expense of $12.9 million was based on a five-year average with a normalization adjustment. She testified that Staff has historically used a five-year average to protect this category of expense, but recommends that a four-year average be used in this case, excluding DTE's 2018 injuries and damage expense of $19.3 million:

> [D]uring the 2018 historical test period, the Company experienced a considerable increase in Injuries and Damages Expense. The 2017 I&D expense was $13.2 million, and the 2018 I&D expense was $19.3 million. When Staff requested support for this significant increase, the Company deemed it to be confidential and cannot be made public and available via the docket records. See Staff Exhibit S-3.2. Staff proposes a calculation of a four-year average for I&D, Staff Exhibit S-3.1, in the amount of $11.3 million by not including the 2018 historical test period expense because of the extreme increase over the previous 4 years expense. This calculation sufficiently smooths the volatility and difficulty of projecting I&D.[716]

She further recommended that the 2018 experience be excluded from the averaging in future cases as well, unless DTE establishes that its injuries and damages expense for that year was reasonably and prudently incurred.[717]

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[715] See May 2, 2019 order, page 90.
[716] See 9 Tr 3278.
[717] See 9 Tr 3278-3279.

In rebuttal, Ms. Uzenski objected to Staff's adjustment, contending that Ms. McMillan-Sepkoski "selected excluded one year . . . because it happens to have a higher I&D expense than the other years." She contended the 2018 experience was not unusually high, stating that past averages have included a single year of expense over $20 million, and she objected to what she characterized as a change in the approved methodology.[718]

In its brief, DTE relies on Ms. Uzenski's rebuttal testimony. Staff addressed Ms. Uzenski's rebuttal testimony in its brief, emphasizing that Staff's adjustment is not based exclusively on the magnitude of the injuries and damages expense for 2018, but also on DTE's confidentiality claim.[719]

This PFD finds that Staff's adjustment should be adopted, and the 2018 injuries and damages expense should not be used in setting rates unless and until DTE establishes that it would be reasonable to expect ratepayers to pay for similar claims.

b. Membership Dues

ABATE recommends that $15.5 million in membership dues and fees be removed from projected test year O&M expenses. Mr. Dauphinais cited Ms. Uzenski's testimony explaining that "certain corporate memberships and advertising, executive incentives, and regulatory assets and liabilities recovered under separate surcharges and not allowable for ratemaking," and thus, DTE's approximately $1 million expenditure on memberships in trade associations is not reflected in rates. He contrasted this with DTE

[718] See 6 Tr 1562-1563.
[719] See Staff brief, pages 74-75.

memberships in other organizations: “[U]nlike the trade associations, DTE’s membership in utility industry associations add millions of dollars to DTE’s revenue requirement. In fact, DTE has recorded nearly $80 million over the last six years to support its membership in utility industry associations.” He presented a list of corporate memberships charged to operating expenses at 7 Tr 1656. Mr. Dauphinais testified that DTE failed to support the $15.465 million expense, and also expressed a concern that groups such as the Edison Electric Institute (EEI), receive a majority of their revenue from utility membership dues, are highly political in nature, promote policies that are not always in the best interest of ratepayers. He testified: “[R]atepayers are subsidizing speech and political advocacy that may run contrary to their personal beliefs and pecuniary interests.”[720] Mr. Dauphinais noted that the Commission has previously approved EEI dues as reasonable and prudent, but recommended that the Commission “at a minimum . . . require DTE to make a showing that ratepayers actually benefit from its Corporate Memberships.” Noting fluctuation in the annual costs as shown in his table, Mr. Dauphinais also recommended the Commission require DTE to support its test year expense and also indicate whether the industry association dues are used directly or indirectly to influence legislation.[721]

In her rebuttal testimony, Ms. Uzenski presented a list of corporate memberships included in the company’s revenue requirement, with a statement of the benefits those memberships provide, in Schedule EE2 of Exhibit A-40. She averred:

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[720] See 7 Tr 1657.
[721] See 7 Tr 1658.

> Memberships in organizations that provide key operational support are allowed for ratemaking purposes. All other corporate memberships are excluded. Any dues paid related to influencing legislation or other political activity are recorded to account 426.4, Expenditures for Certain Civic, Political, and Related Activities, which is excluded from base rates.[722]

In a discovery response and in cross-examination, Ms. Uzenksi acknowledged a $4,000 error reflecting her failure to exclude American Gas Association membership dues,[723] and a $281,175 error relating to an organization that should have been fully excluded.[724]

Staff accepted Ms. Uzenski's adjustments in its brief.[725] ABATE argues that even in rebuttal, DTE did not establish the reasonableness and prudence of the expenditures.[726] ABATE contends that Ms. Uzenski acknowledged it was her responsibility to ensure that political and lobbying expenses were removed, but instead she merely assumed they were, subsequently acknowledging two errors.[727] ABATE argues that in addition to removing political and lobbying expenses, DTE must show that these costs are reasonable. ABATE then contends that providing ratepayer funding for DTE's dues and memberships is "effectively unconstitutional compelled speech."[728] ABATE asserts that the entities listed on page of Exhibit AB-37 "engage in precisely this type of advocacy and speech," and asserts that DTE has the burden of proving otherwise.[729] Citing Ms. Uzenski's cross-examination testimony in which she

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[722] See 6 Tr 1565.
[723] See 6 Tr 1609; Exhibit AB-8.
[724] See 6 Tr 1616; Exhibit AB-8.
[725] See Staff brief, pages 78-79.
[726] See ABATE brief, pages 56-62.
[727] See ABATE brief, page 58.
[728] See ABATE brief, pages 59-62, citing *Harris v Quinn*, 573 US 616, 656; 134 S Ct 2618, 2644; 189 L Ed 2d 620 (2014); *Thomas M. Cooley Law School v Doe 1* 300 Mich App 245, 275 (2013); *Consolidated Edison Co of New York, Inc. v Pub Serv Comm of New York*, 447 US 530, 543; 100 S Ct 2326; 65 L Ed 2d 319 (1980).
[729] See ABATE brief, page 61.

acknowledged that she did not know whether the groups listed on page 1 of Schedule EE2 have a lobbyist or government affairs person on their staff, ABATE contends that Ms. Uzenski was unable to confirm basic facts about the industry groups' activities.[730] In its reply brief, the MEC Coalition supports ABATE's position.[731]

DTE argues in its brief, however, that Ms. Uzenski's testimony shows that memberships in organizations that provide key operational support are allowed for ratemaking, and that DTE has a careful review process and conservative exclusion of certain items from the Company's requested rate recovery. DTE argues that her careful scrutiny revealed the two items that should be removed from DTE's rate request in this case.[732] After repeating these arguments in its reply brief,[733] DTE argues that ABATE's brief added nothing to the discussion, and then acknowledges ABATE's argument regarding compelled speech, responding:

> The Company disagrees but declines to belabor the point because the Commission lacks jurisdiction to decide ABATE's suggested constitutional issue. *Wikman v Novi*, 413 Mich 617, 646-47; 322 NW2d 103 (1982) ("an agency exercising quasi-judicial power does not undertake the determination of constitutional questions or possess the power to hold statutes unconstitutional").[734]

This PFD finds the record does not support excluding the membership fees for all associations as ABATE requests, and does not provide a basis for evaluating the activities of the associations. In Schedule EE2 of Exhibit A-40, Ms. Uzenski indicates that

[730] See ABATE brief, page 61, citing 6 Tr 1614.
[731] See MEC Coalition reply, page 3.
[732] See DTE brief, page 137.
[733] See DTE reply brief, pages 79-80.
[734] See DTE reply brief, page 80.

DTE's membership in several of these organizations is required.[735] The Commission has recently reviewed EPRI, and concluded that ratepayer funding is appropriate, and an example of its activities is presented in this case, through Mr. Bruzzano's testimony. Similarly, the North American Electric Reliability Association (NERC) standards are frequently a subject of testimony in Commission cases so its activities are well-known to the Commission. While Ms. Uzenski did not know certain details regarding some of the organizations, the cost of these memberships has been included in rates in prior cases and there is no evidence on the record to show that these organizations engage in lobbying or political activity the costs of which are not otherwise excluded as required by accounting rules, or that they engage in any form of speech that would constitute compelled speech by customers.

9. Pensions and Benefits (Schedule C5, line 11; Schedule C5.11)

There are two outstanding issues regarding DTE's projected benefits expense that have not been addressed, the Attorney General's recommended reduction to DTE's projected wellness expense, and DTE's projected incentive compensation expenses.

a. Wellness

Mr. Cooper testified to support the expense projections on Schedule C5.11, including the projected "wellness" expenses.

Mr. Coppola took issue with the increase in DTE's projected test year spending on its employee wellness program over historical levels:

[735] See Institute of Nuclear Power Operations, Nuclear Energy Institute, Inc., and US Nuclear Regulatory Commission.

> The Company has consistently spent between $1.8 million to $2.2 million on its “wellness” program during the 2014 to 2018 timeframe. However, for the projected test year the Company proposes a doubling of the expense amount from $2.2 million in 2018 to $4.5 million for the projected test year. The direct testimony of witness Cooper, who sponsors the wellness program, is completely devoid of any explanation as to how the Company plans to spend the additional funds for the program. In discovery, the Company was asked to explain the reasons for the increased spending on the wellness program and to provide any studies the Company has conducted regarding why the additional expenditures are justified.
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> In response, the Company did not provide any studies performed to justify the increase in expense and instead provided two published articles supporting the concept of wellness expenditures. In discovery, the Company was asked to provide a list of other utility companies and the amount they spend on wellness programs. The Company replied that it had not compiled such information.[736]

In rebuttal, Mr. Cooper testified:

> While the specific elements of the enhanced Wellness program were not finalized when my Direct testimony was filed, it has since been identified that the initial components of the enhanced Wellness program will focus on the three highest risk health risk factors of the Company’s employees: obesity, hypertension and high blood sugar levels. Accordingly, the majority of the expected increase in Wellness program costs will relate to pre-diabetes/diabetes prevention and management programs and cardiovascular management programs. Further, the Company will be expanding its employee training and awareness programs focused on injury prevention.[737]

Mr. Cooper also testified that DTE’s projected test year O&M includes a projected savings of $483,000 attributable to additional wellness activities.[738]

In her brief, the Attorney General addressed Mr. Cooper’s rebuttal testimony, arguing that even in rebuttal, he did not provide sufficient specificity to support the

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[736] See 9 Tr 3063.
[737] See 5 Tr 961.
[738] See 5 Tr 963.

projected expense increase.[739] The Attorney General "takes issue with DTE proposing cost forecasts and recovery for programs with uncertain parameters, which are not specifically understood."[740] She also cites cross-examination of Mr. Cooper at 5 Tr 972, arguing that his responses show the contours of this program are not sufficiently well outlined to support recovery. DTE argues that Mr. Cooper's testimony provides adequate justification for the expenditure.[741]

This PFD finds the Attorney General's adjustment is warranted. While wellness activities as a concept are reasonable and desirable, DTE failed to take advantage of the appropriate opportunity to demonstrate that has reliable plans to spend the projected amount, and that its actual plans are reasonable and prudent. While DTE did not meet this standard in its rebuttal presentation, as the Attorney General argues, DTE may not reserve expense allowances in its initial filing and figure out the details by the time its rebuttal presentation is due. The Attorney General also followed up on DTE's rebuttal testimony with additional discovery; as shown in Exhibit AG-1.48, DTE did not indicate the extent to which DTE's proposed additional spending relates to health program expenditures already covered in rates.

Nonetheless, for consistency, this PDF agrees that projected savings of $0.48 million should be deducted from the projected expense.

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[739] See Attorney General brief, pages 51-53, also citing Cooper, 5Tr 971.
[740] See Attorney General brief, page 50.
[741] See DTE brief, pages 141-142.

b. Incentive Compensation

In its order in Case No. U-20162, the Commission permitted DTE to include incentive compensation expenses attributable to attaining the non-financial operational measures, but declined to permit DTE to recover projected expenses associated with attaining financial measures:

> The Commission is not persuaded by either DTE Electric's or the Attorney General's arguments and adopts the findings and recommendations of the ALJ with regard to the disallowance of employee incentive compensation tied to financial measures and allowance of compensation tied to achievement of non-financial performance objectives. This is consistent with 11 prior Commission decisions and is reasonable and prudent given that incentive compensation tied to financial performance measures has not been shown to benefit ratepayers. PFD, pp. 171- 172; see Staff's initial brief, pp. 67-68 (listing the 11 cases). The Commission agrees with the Staff and the ALJ that the company failed to present any new information persuading the Commission to deviate from its prior orders disallowing this O&M category.[742]

While not adopting the Attorney General's recommendation to exclude 50% of projected incentive compensation expenses associated with operational measures to reflect DTE's historical failure to achieve those measures, the Commission provided the following additional directive to DTE:

> Notwithstanding the continuation of this approach, the Commission directs DTE Electric to provide additional detail on compensation, performance targets, and achievement in its next rate case to allow the Commission to evaluate whether adjustments should be made for the non-financial incentive structure authorized for recovery in rates.[743]

Mr. Cooper presented DTE's request to include projected incentive compensation expenses for both financial and non-financial measures totaling $47.6 million in the test

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[742] See May 2, 2019 order, page 93.
[743] See May 2, 2019 order, pages 93-94.

year revenue requirement.[744] Mr. Cooper described DTE's overall approach to compensation and its executive compensation before turning to programs underlying the company's incentive compensation request. He testified that DTE has incentive compensation plans for its executive and non-represented employees, with short-term plans called the Annual Incentive Plan (AIP) for executives and the Rewarding Employees Plan (REP) for non-represented employees.[745] Mr. Cooper explained that the two plans are identical except for the minimum payments for threshold performance and the maximum payouts for above-target-level performance. He presented the measures and weightings for the AIP and the REP, separately for DTE Electric other than nuclear generation, DTE Electric nuclear generation, and DTE Energy Corporate Services in Schedules k4 through K6 of his Exhibit A-21, and discussed each of the four categories of measures, "Financial Performance, Customer Satisfaction, Safety and Engagement, and Operating Excellence," for DTE Electric (non-nuclear) and DTE Electric Nuclear Generation employees.[746] He testified that the measures for DTE Energy Corporate Services include the same measures as for DTE Electric, as well as measures related to gas. Mr. Cooper also identified DTE's Long-Term Incentive Plan (LTIP), which he described as follows:

> The Long-Term Incentive Plan (LTIP) provides certain individuals the opportunity to receive retention-oriented and/or performance-based rewards delivered via shares of DTE Energy common stock, through either Restricted Stock or Performance Shares, which are based on the achievement of multiyear performance objectives. For Executives and Director level employees, 30% of the value of awards is through Restricted Stock and 70% is through grants of Performance Shares, while 100% of the

[744] See 5 Tr 917-947.
[745] See 5 Tr 928, 924.
[746] See 5 Tr 929-935

> awards to employees below the Director level are through Performance Shares. The objective in granting shares through this program is to both motivate superior results as well as provide a means to retain key employees and is consistent with the practices of 88% of surveyed companies, as reflected in the WorldatWork and Deloitte Consulting LLP referenced above.[747]

He testified that the measures used to award performance shares for the LTIP are shown in Schedule K7 of Exhibit A-21. For DTE Electric, he identified the predominate measure as total return to DTE Energy shareholders relative to a group of peer companies over the next three years, with the other two measures including DTE Energy's Funds From Operations to Debt ratio, and DTE Electric's three-year return on equity.[748] Mr. Cooper described these measures as reflecting "the long-term financial performance of DTE Energy and are intended to motivate employees of the individual operating companies, such as DTE Electric, to keep in mind the role of their own contributions to the overall long-term success of DTE."[749] For DTE Corporate Services LLC, the only measures are total return to shareholders and the FFO to Debt ratio. Mr. Cooper presented a chart at 5 Tr 938 showing the projected expenses by plan, separately for each employee group, and separately for financial and operating measures.

Mr. Cooper testified that DTE's $47.6 million expense projection for its incentive compensation program excludes $10.5 million in incentive compensation expenses related to DTE Energy's top five Executive Officers, as reflected in Schedule C20 of Exhibit A-3. He also testified that it excludes $3.7 million in restricted stock shares paid

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[747] See 5 Tr 935-936.
[748] See 5 Tr 937.
[749] See 5 Tr 936.

out under the LTIP program that are not awarded based on performance, but are forfeited if an employee leaves the company prior to retirement, death, or disability.[750]

Mr. Cooper cited the prevalence of incentive compensation programs in the market. He acknowledged the Commission's order in Case No. U-20162, including incentive compensation relating to operating measures but not financial measures, and also directing DTE to provide additional detail "to allow the Commission to determine whether adjustments should be made for the non-financial incentive structure."[751]

After this acknowledgement, Mr. Cooper testified that he does not agree that incentive compensation related to financial measures should be excluded from the company's revenue requirement, contending that the Commission's decisions on this expense item "overlook the more important issue of the overall reasonableness of total compensation."[752] He presented Schedule K1 of his Exhibit A-21 to illustrate that DTE's compensation practices are competitive with the market medians.[753]

Turning back to the analysis requested by the Commission, Mr. Cooper testified that Schedule K3 of his Exhibit A-21 contains a summary of the company's actual annual performance relative to the thresholds, targets, and maximums for the non-financial measures for the years 2014-2018. He testified that the average results were 92% for the AIP and 79.9% for the REP, which he contends demonstrates the company is performing very near to target levels.[754]

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[750] See 5 Tr 939.
[751] See 5 Tr 919.
[752] See 9 Tr 919-920.
[753] See 5 Tr 920-924; also see Cooper, 5 Tr 926-927.
[754] See 9 Tr 924.

Mr. Cooper also presented what he characterized as a comprehensive analysis of the customer benefits that would be derived from the achievement of the financial and operating metrics in DTE's plans. He included this analysis in Schedule K8 of Exhibit A-21, and discussed it further in the balance of his testimony, concluding:

> While not every individual measure has quantified benefits in excess of the incentive compensation expense of the related measure, it is clear that in aggregate, the quantified customer benefits of the Company achieving Target performance levels for both the financial and operating measures are substantially greater than the related expense. Moreover, in those instances where the quantified benefits are less than the related expense (i.e., customer satisfaction and safety), the non-quantifiable benefits are undoubtedly substantial.[755]

Ms. McMillan-Sepkoski presented Staff's recommendation that the Commission retain its past practice and permit recovery only of the incentive compensation associated with the non-financial operational measures, a projected expense of $19,169,000.[756]

Mr. Coppola testified to his opinion that the three plans are too heavily skewed toward measures that benefit shareholders rather than customers, and that DTE estimates of customer benefits "are based on a faulty premise of historical cost savings and an expectation that future targets of performance will be achieved."[757] He testified that the financial measures primarily benefit shareholders, and recommended rejection of all associated costs.

For the non-financial measures, Mr. Coppola reviewed the benefits and costs as presented in Schedule K8 of DTE's Exhibit A-21. For the Customer Satisfaction and

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[755] See 5 Tr 946-947.
[756] See 9 Tr 3279-3280. She also explained DTE's post-filing minor revisions to its expense projections for this category.
[757] See 9 Tr 3066.

Employee Engagement categories, he concluded that the benefits achieved are below the costs. For the Operating Excellence category, he testified:

> The only measures that have a direct link to customers are the Electric outage metrics (SAIDI and CAIDI), which represent a small portion of the expected payout. Moreover, improvements in this area will be largely a function of a more aggressive tree trimming program which is largely contracted out and paid for through increases in customer rates.[758]

Mr. Coppola also took issue with Mr. Cooper's testimony that DTE's performance is at 92% for the AIP and 79.9% for the REP programs, and thus very near the target level:

> Exhibit A-21, Schedule K3 Revised provides a different picture, especially with respect to 2018, which is the most recent year of experience. As can be seen on lines 38 through 43 of this exhibit page, the Company performed at "less than Threshold" for 11 of the 32 metrics in 2018 and below Target on another 5 of the 32 metrics. Adding these two categories together, the Company is below the Target 50% of the time in 2018. Moreover, if one considers 2018 compared to 2017, only 7 metrics were below Target in 2017 (vs 18 in 2018)—suggesting a decline in performance levels or at least a decline in outcomes relative to management's expectations.[759]

Explaining that based on the historical percentage of operating measures attained in 2018, 30%, he could recommend that DTE recover only 30% of its projected incentive costs for the non-financial measures, he instead recommended that 50% of the projected costs for the non-financial measures be included, characterizing a 30% recovery as "punitive, especially since it would be dependent upon just on year of performance results."[760] He thus proposed a test year incentive compensation expense amount of $9.6 million, a $38 million reduction to DTE's requested amount.

[758] See 9 Tr 3067-3068.
[759] See 9 Tr 3069.
[760] See 9 Tr 3072.

In rebuttal, Mr. Cooper reiterated his view that the Commission should include projected costs associated with financial measures in O&M, reiterating the claims that DTE's overall compensation levels with the incentive compensation are reasonable, and asserting benefits to ratepayers.[761] Mr. Cooper also objected to Staff's proposed exclusion of the portion of DTE's long-term incentive compensation plan that awards restricted stock to employees simply based on longevity, with a projected value of $3.670 million.[762] Mr. Cooper testified that these awards do not turn on any level of financial performance by the company. Mr. Cooper also objected to Mr. Coppola's analysis of the DTE's performance on the operating measures, also objected to his conclusion that recovery should be limited to 50%. Mr. Cooper presented an alternative analysis in Schedule X2 of Exhibit A-33, to show that only 38.46% of operating measures for the DTE REP plan in 2018 were below threshold performance, with an average of 31.2% across all REP plans, and for the AIP plans on average, only 28.57 operating measures were below threshold levels.[763] He also presented corresponding figures for the five-year period 2014-2018.[764]

In her brief, the Attorney General argues that the Commission should exclude not only the $28.4 million associated with financial measures, but also 50% of the projected expenses associated with operational measures. The Attorney General addressed Mr. Cooper's rebuttal testimony regarding the benefits of financial measures by citing cross-examination of Mr. Cooper at 5 Tr 966. The Attorney General argued that being fiscally

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[761] See 5 Tr 950-952; 955-957.
[762] See 5 Tr 952-953.
[763] See 5 Tr 958-959.
[764] See 5 Tr 959-960.

responsible and keeping O&M costs low should be a basic expectation for management employees to earn base pay, and contended that Mr. Cooper "hedged" and was vague under cross-examination when asked about the base-level expectations for employees.[765] Addressing Mr. Cooper's rebuttal testimony and Schedule X2 of his Exhibit A-33, the Attorney General argued that the 30% figure he cited reflects operational measures not achieved at even a threshold level, while the same exhibit shows that only 55% of operational measures over the time period were achieved at the target level in 2 of the last 3 years.[766]

DTE's briefs primarily restate Mr. Cooper's testimony, arguing that DTE's overall compensation levels are reasonable and contending that ratepayers benefit from the financial as well as the operating measures. This PFD finds that DTE has provided no new evidence or analysis that indicates the Commission's prior findings on this expense category are erroneous. DTE merely raises the same claims it has raised in case after case. DTE contends that a benefit from its financial measures is DTE's maintenance of its credit rating, but ratepayers pay a great deal of money to help DTE maintain its credit rating already. Indeed, in Case No. U-20162, the Commission included $934,862,000 in DTE's rates, before application of the revenue multiplier of 1.3496, to cover interest payments on debt and a return on equity of 10%. DTE's rates are include depreciation and amortization expenses of another comparable amount, and O&M expense projections of well over $1 billion. DTE has not established why it is fair or reasonable for

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[765] See Attorney General brief, page 55-56.
[766] See Attorney General brief, pages 56-58.

ratepayers to fund an additional $28 million to help DTE maintain its current credit rating, or why it is appropriate to use the cost associated with a one-notch change in DTE's credit rating as a "benefit" of DTE's financial measures.

DTE also disputed Staff's adjustment for the portion of DTE's long-term incentive plan (LTIP) in which restricted stock is awarded to certain employees based on longevity. DTE argues that because no level of financial performance is required to earn the restricted stock award, the $3.67 million projected cost should be included in test year O&M.[767]

Staff argues the value of the restricted stock awards should be excluded from O&M.[768] Staff cites Exhibit S-8.6 in arguing that the goal of the restricted stock award is to enable the recipient to share in the value created for shareholders, as a reward for sustaining the company's profitable growth, and to link the recipients' rewards to long-term financial results. This PFD finds that Staff has correctly analyzed the expense and it should be excluded from test year O&M. While DTE disputes the applicability of some of the language in Exhibit S-8.6 to the "restricted stock" component of the LTIP, Exhibit S-8.6, page 3, clearly states:

> When you own shares in the Company, you benefit financially when DTE Energy Company stock increases as well as when the Board authorizes a dividend. As a leader, you have the ability to make decisions that result in meeting or exceeding both short-term and long-term goals. When we achieve our goals, we are more likely to see our stock price increase.

[767] See Cooper, 5 Tr 953-955. Note Mr. Cooper revised his original testimony to exclude this restricted stock value from the incentive compensation total. See 9 Tr 938.
[768] See Staff brief, page 77.

10. Taft-Hartley Training Trust

The UWUA Local 223 requests that the Commission require DTE to set aside training funds. Mr. Harmon is the Executive Director for the UWUA Power for America Training Trust Fund. He presented several exhibits designed to show the concerns raised by a gaining utility workforce, both nationally and in Michigan. He explained the training benefits provided by P4A, discussing examples in California, Ohio, and Illinois.[769] He recommended that the Commission carefully examine projected training costs in DTE's rate request in light of workforce graphics and the aging workforce. He recommended that the Commission require DTE to document how it plans to deal with the crisis, and further require DTE to partner with P4A:

> [A]t present there is no requirement that funds allocated for training be externally funded, so there is no certainty that sufficient funds will in fact be used to address the crisis of DECo's aging workforce. The Commission should therefore require DECo to partner inP4A, to ensure that the necessary funds are externally funded and available for training the new workforce that must emerge to provide quality service to the public.[770]

Mr. Smith is responsible for the day-to-day operations of Local 223. After discussing national and local demographic trends to show DTE's workforce is aging, with increasing retirements, he testified that this presents a challenge for DTE both in hiring and training:

> DECo is posed with an additional challenge because senior employees have traditionally provided training for new employees in DECo training and apprenticeship programs. In recent years there have been a significant number of retirements. While the Company has made efforts to replace those workers there still is a significant shortage of skilled, clerical, and other employees, who can provide quality training to the Company's new recruits. The ratio between trainers and apprentices is significantly out of balance. Simply put, this imbalance has created a scenario where there are

[769] See 9 Tr 2744.
[770] See 9 Tr 2746.

> not enough experienced employees to provide training to new employees. This imbalance places great pressure on experienced employees who are responsible for providing both on-the job training and classroom training. Externally funded training programs like the UWUA Power for America Training Trust Fund ("P4A") could help reduce some of this pressure by providing additional trainers and/or by taking responsibility for the classroom component of DECo's apprenticeship and training programs.[771]

DTE argues that the external funding of a Taft-Hartley trust is strictly a question for collective bargaining. Staff cites Union Carbide in arguing that the Commission cannot require DTE to fund the training trust. DTE also expresses a shared concern about the talent loss due to retirements and the need to train new utility workers:

> The Company shares the indicated concerns about the talent loss due to retirements, and the need to train new utility workers. The Company therefore continues to work with the UWUA to inform solutions for this and other labor-related challenges to DTE Electric; however, selecting solutions to these challenges is ultimately the responsibility of the Company's management (4T 506).[772]

DTE also argues that its current reporting obligations are adequate to address these concerns:

> There is similarly no necessity nor other basis for an additional report as suggested at UWUA Initial Brief, pp 14-15, particularly in light of the Company's existing reporting requirements. For example, in compliance with the Commission's surge reporting requirements (May 2, 2019 Order in Case No. U-20162, p 81), the Company will provide annual reports starting March 1, 2020, and a Tree Trimming Effectiveness Report in 2022 (9T 3626-27). Staff recommended that in the annual report, "DTE Electric discuss progress the Company is making toward achieving an adequate level of qualified local workers in the tree trimming workforce" (9T 3231-32). The Company agrees to provide an update on the number of local journeymen and the number of local apprentices in its annual reports for the duration of the surge program. The Company will also provide updates on any programs in which it is participating to increase the number of local tree trimmers (9T 3631).[773]

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[771] See 9 Tr 2751-2752.
[772] See DTE reply brief, page 70
[773] See DTE reply brief, pages 70-71.

This PFD finds that DTE's reporting is a reasonable approach, although in view of the issues discussed in connection with its strategic capital, DTE should also identify and workforce and training issues that would interfere with its ability to complete its strategic capital investments as well.

11. Case No. U-20084 Expenses

The RCG asks the Commission to ensure that DTE is not seeking to recover expenses to comply with the Commission's order in Case No. U-20084.[774] The RCG does not identify any specific costs associated with DTE's compliance with that order that are included in this case in contravention of that order. This PFD does not recommend any specific adjustment.

12. TCJA-Related Potential Cost Savings

The RCG also argues that DTE should be encouraged to seek cost reductions from suppliers and contractors, on the theory that their costs have fallen due to the TCJA.[775] RCG cites Exhibit RCG-9 to show that DTE is undertaking some efforts. Consistent with the foregoing discussion, between rate cases DTE clearly has an incentive to seek cost reductions. In the absence of specific requested adjustments, this PFD does not recommend any.

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[774] See RCG brief, pages 20-27.
[775] See RCG brief, pages 27-28.

C. Other Expenses

1. Tax Expense

No party took issue with DTE's projected tax expense calculation, with the exception of ABATE's recommended regulatory plan, which was addressed above. There is thus no further dispute regarding the calculation of property tax, federal income tax, or state and local taxes. The different tax amounts reflect different levels of projected expenditure.

2. Depreciation and Amortization

There are no disputes regarding the depreciation rates or amortization periods for rate base or other amortizable expense items. To the extent the parties differ regarding amortization expense amounts, those issues were addressed for convenience above in connection with working capital.

3. AFUDC

There was also no dispute between the parties regarding the calculation of AFUDC. The differences are driven by different projected capital expenses.

D. Adjusted Net Operating Income Summary

Based on the discussion above, this PFD recommends an adjusted net operating income of approximately $855 million as shown in Appendix C.

VIII.

REVENUE DEFICIENCY

Based on the foregoing recommendations, this PFD recommends a revenue deficiency of $99.94 million, as shown in Appendix A.

IX.

OTHER REVENUE-RELATED ITEMS

A. Surge Funding Extension and Reporting

In Case No. U-20162, the Commission approved DTE's request for surge program funding for three years, through 2021. Ms. Rivard described the surge program, and the enhanced tree-trimming practices (ETTP) DTE has been using. She reviewed DTE's 2018 operations, and explained the variability in work volume by mile trimmed. She testified to DTE's plans for 2019, and provided a performance analysis of the ETTP practices. She also identified improvements DTE has made to its tree-trimming practices, including fixed-bid contracts, a "mowing alley pilot" in Detroit, and an herbicide program. And she identified initiatives including improvements in production using innovative tree-trimming equipment, improved tree counts and tree density information, and an estimating team composed of company arborists to negotiate accurate pricing with contractors. She endorsed Mr. Bruzzano's testimony that tree-trimming is the higher-priority investment, and testified that DTE is committed to a five-year cycle, further explaining that it will take 7 years of surge funding to achieve a five-year cycle. In comparison to the company's plans as presented in Case No. U-20162, she testified that DTE has reduced its planned miles for 2019 to concentrate on "more unit intensive miles" to reduce high trouble volumes.[776] After reviewing the benefits from the surge program and the expected benefits from attaining a five-year clearing cycle, she explained DTE's request for an extension in the surge funding to "provide the Company the financial security needed to

[776] See 9 Tr 3608.

retain contractors and grow the local work force." The amount requested for 2022 is $58.2 million. She testified that DTE has significantly ramped up its 2019 spending to meet the program commitment, noting that DTE spent $61.2 million through May 2019, and is projected to reach the total projected expenditure of $134.6 million. Ms. Rivard also explained DTE's workforce of tree-trimmers, risks to DTE's ability to retain this workforce, and initiatives underway to create additional local tree-trimmers.[777] She testified that starting March 1, 2020, DTE will begin filing annual reports on circuit performance, with a report on effectiveness to be submitted in 2022.

Mr. Evans explained Staff's support for the increase, testifying that although the surge program has only been in effect since the beginning of 2019, DTE has been using ETTP since 2015 and the practice is beneficial.[778] He recommended that in its annual report on the program, DTE discuss its progress toward achieving an adequate level of qualified local workers, citing Ms. Rivard's testimony.[779]

Mr. Coppola objected to the request. He testified:

> There is no need to further expand the program at this point, as the Company requests. The Commission approved a three-year period of funding for this costly program in order to ascertain if the surge program was achieving the claimed benefits, before approving a longer-term program. Nothing of significance has changed since the Commission decision in May 2019 that justifies extending approval for another year through the year 2022. The main reason that Ms. Rivard offers in her direct testimony is that tree trimming contractors may go to other states if there is no assurance that the DTEE tree trimming surge program will continue through 2022.
>
> This claim is perplexing, because in response to discovery DTEE disclosed that the current contracts with tree trimming contractors expire on

[777] See 9 Tr 3622-3624.
[778] See 9 Tr 3231.
[779] See 9 Tr 3231-3232.

> January 1, 2020 and the Company is currently negotiating new three-year contracts with contractors that will begin in January 2020. These contracts would span through January 2023. The new contracts should remove any concerns about not having contractors for the year 2022. Furthermore, if the Company strongly believes that over the coming three years the surge program has achieved the benefits claimed in Case No. U-20162, it can proceed with the required amount of surge spending for 2022. The Company can later request inclusion of those costs in the regulatory asset for future recovery in a subsequent rate case.[780]

Mr. Coppola opined that insufficient time had passed to allow for an assessment of the merits of the program.[781]

In her rebuttal testimony, Ms. Rivard acquiesced to Mr. Evans's requested workforce reporting.[782] She also disagreed with Mr. Coppola's objection, asserting that she provided sufficient evidence that the surge program is effective in reducing outage events, customer interruptions, customer outage minutes, and downed wires.[783] She acknowledged that DTE had signed 3-year contracts, but testified that the contracts "do not guarantee any volume of maintenance work." She further asserted:

> If the Company cannot provide work volume guarantees in 2021 for the full 2022 Surge Program work volume, then contractors will likely elect to move some of their trimmers and equipment to other areas of the country where they have guaranteed work volumes.

Based on Ms. Rivard's rebuttal testimony, this PFD recommends that the Commission wait until DTE's next rate case to consider the additional surge funding. DTE's March 2020 report will be available then. DTE will have the opportunity to demonstrate one full year of successful spending under the program. Assuming DTE

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[780] See 9 Tr 3051-3052.
[781] See 9 Tr 3052.
[782] See 9 Tr 3631.
[783] See 9 Tr 3633.

repeats its recent pattern of rate cases, DTE should file its next rate case around July 2020, with a Commission order expected in May 2021, which should be ample time to meet Ms. Rivard's stated deadline of 2021 for the company to provide work volume guarantees.

As noted above, Staff also requested additional reporting regarding the surge program that DTE agreed to. As discussed above regarding worker training, since DTE has had difficulty completing strategic capital investments in addition to its emergent replacement and new construction obligations, this PFD also recommended that DTE include other distribution system workers in its reporting.

B. DTE Accounting Requests

DTE seeks Commission approval of three accounting requests. First, DTE requests an increase in the Program Evaluation and review Committee (PERC) base to $15 million. Mr. Davis and Ms. Uzenski discussed this request in their testimony. Ms. Uzenski testified that DTE has incurred costs well above the $4.9 million base since it was originally approved in Case No. U-18014, citing Schedule C5.17 of Exhibit A-13. Mr. Davis projected annual expenses from $16 million to $19.9 million. She testified that the regulatory asset balance as of December 2018 was $43.4 million, and that should annual expenditures fall below the base level, the remainder of the $15 million would be used to reduce the regulatory account balance. No party opposed DTE's request, so this PFD finds that it should be granted.

DTE also asks that the Commission authorize continuing deferral of net Other Post Employment Benefits (OPEB) expenses. Citing Ms. Uzenski's testimony, it explained:

> The Commission approved the Company proposal to defer negative OPEB expense to a regulatory liability (December 11, 2015 Order in Case No. U-17767, p 69), and to continue that deferral (January 31, 2017 Order in Case No. U-18014, pp 94-95; April 18, 2018 Order in Case No U-18255, p 34, n 8; May 2, 2019 Order in Case No. U-20162, p 91). The Company proposes a continuation of the OPEB deferral until the regulatory liability fully absorbs any future OPEB expense, with any resulting debit balance to be reviewed in a subsequent rate case. Therefore, the negative OPEB expense is not included in the Company's proposed revenue requirement, and there is no obligation for the Company to fund its OPEB liability (5T 902-903).[784]

Once again, no party objected to DTE's request. This PFD therefore finds that it should be granted.

Additionally, DTE asks for approval to record certain deferred costs associated with cloud computer services as other assets in Plant, Property and Equipment (PP&E), rather than in Plant in Service, to comply with Accounting Standards Update (ASU) 2018-15, "Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract."[785] Again, it does not appear that any party objected, so this PFD finds DTE's request should be granted.

DTE's request to authorize the creation of a regulatory asset for pension expenses is addressed above, with the recommendation the request be denied.

C. <u>TCJA Accounting and Reporting Requirements</u>

The Attorney General and Staff each recommend that the Commission establish a regulatory asset/liability to record the annual differences between the excess deferred tax expense included in rates and the actual amortization amounts for each type of excess deferred taxes.[786] Staff and the Attorney General also recommend the Commission

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[784] See DTE brief, page 140.
[785] See 6 Tr 1556; DTE brief, page 154.
[786] See Attorney General brief, pages 109-111; Staff reply brief, page 40.

require DTE to report on its amortization of excess deferred tax balances resulting from the TCJA. Mr. Nichols recommended that DTE be required to file an annual letter each March 31 in this docket detailing the annual activity related to the excess deferred federal income taxes, including the following information, separately stated for protected and unprotected balances:

> (1) the beginning refundable balance;
>
> (2) the yearly amount included in rates;
>
> (3) the over/under regulatory asset/liability the company has recorded, which shall be calculated as the differences between the actual amount of excess deferred taxes in a given year and the estimated amount included in rates; and
>
> (4) the ending refundable balance.[787]

Mr. Nichols testified that other utilities have been required to file such a letter, including DTE Gas, and he cited the relevant dockets. Mr. Coppola similarly recommended that DTE be required to report on its excess deferred federal income tax balances.[788] DTE did not object.

This PFD finds that these recommendations are reasonable and should be adopted.

D. <u>Analytic and Other Reporting Issues</u>

This section addresses requests for further analyses and reporting that were not addressed above.

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[787] See 9 Tr 3332.
[788] See 9 Tr 3076-3077.

1. Line Loss Study

Staff recommends that DTE conduct a line loss study before its next rate case. Mr. Gottschalk testified that DTE had not conducted a loss study since 1999. He testified that DTE's system has undergone many changes in that time period, including numerous investments and its acquisition of the Detroit Public Lighting Department's system.[789]

Mr. Jester also identified a number of changes taking place since 1999, including substantial changes in the sales mix and the geographic distribution of customers.[790] He recommended that the Commission reject DTE's proposed increase in the line loss factor based on its sales and generation forecasts, as discussed above, and also require DTE to conduct a loss study. He recommended that the loss study be filed in this docket within 6 months. He also testified that DTE's study should provide hourly losses for a full year and also statistically relate those losses to loads by rate class, explaining that upcoming distribution planning efforts, the evaluation of EV charging programs and distributed generation, and energy waste reduction and demand response efforts require consideration of marginal costs.[791]

Mr. Krause testified in rebuttal that Staff for the most part agrees with Mr. Jester's analysis, but offered this additional explanation:

> [A] shortcoming of Mr. Jester's testimony is that he focuses on engineering losses and does not discuss the other reasons for the difference between generation and sales. Other factors include, but are not limited to, meter inaccuracy, the difference between estimated and actual service, and theft.[792]

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[789] See 9 Tr 3251.
[790] See 9 Tr 3804-3806.
[791] See 9 Tr 3807.
[792] See 9 Tr 3390.

Mr. Krause indicated that actually incorporating all of these factors into an hourly marginal line loss for cost-of-service purposes may be difficult or potentially inappropriate. Thus, he testified that Staff did not necessarily support a requirement that DTE conduct a marginal loss study.[793] Staff calls for a line loss study in its brief, but echoes Mr. Krause's caution regarding a marginal loss study.[794] In its reply brief, DTE agrees to conduct a loss study, but also agrees with Mr. Krause that a marginal line loss study "may not be appropriate."[795]

In its reply brief, the MEC Coalition argues the caution is misplaced, arguing that Staff is speculating without evidence that it may be difficult to assign non-engineering losses on an hourly basis:

> Since it has been over 20 years since DTE's last engineering loss study, there is little recent local experience to inform such a conclusion. But even if it is difficult to evaluate non-engineering losses on an hourly basis, that bears not at all on whether DTE should evaluate engineering losses on an hourly or marginal basis. In other words, DTE should not be excused from conducting an engineering loss study on both an average and marginal basis due to challenges associated with non-engineering losses.[796]

This PFD finds that DTE should be required to conduct a line loss study before its next rate case, and since DTE has not objected to either the time required or the cost of the analysis, it should endeavor to complete the marginal loss study described by Mr. Jester or provide a detailed explanation of what appropriate limitations it imposed on its analysis. Clearly, the company's distribution system is a focus of substantial investment for the utility, and additional insight into the operation of that system would seem to be

[793] See 9 Tr 3390-3391.
[794] See Staff brief, page 101.
[795] See DTE reply, page 107.
[796] See MEC Coalition reply, page 35.

valuable as Mr. Jester testified. This says nothing about the usefulness or appropriateness of the resulting information for cost of service study purposes, which the parties would always be free to debate.

2. Reporting of AMI Benefits

Once again, the parties dispute whether DTE should continue to report on AMI benefits as required by prior orders. Ms. Robinson testified that as of April 1, 2019, DTE installed over 2.6 million AMI electric meters and 1,226,000 gas modules, but:

> Due to numerous customer related issues, including but not limited to, Can't-Get In's (CGI's), vacant properties, locked gates, lack of customer response, etc., the Company is still working to complete the remaining 631 installments of AMI electric meters in 2019.[797]

She also testified that DTE is working on several new ideas for leveraging AMI technology, including the identification of power quality problems; creating daily outage statistics; enhancing the tree-trimming program by using the frequency of momentary outage interruption data experienced at a customer meter; enhancing automatic closure algorithms to identify areas where power has been restored and performing other storm-related work; and modeling electric grid voltage levels. She presented Exhibit A-19, Schedule 11, to comply with the Commission's directive in Case No. U-18255 to report on AMI benefits, but recommended that the reporting be discontinued.[798]

Staff objected to discontinuing the AMI benefit reporting. Dr. Wang testified that the benefit forecast information DTE provided does not comply with the requirements established by the Commission in Case No. U-18255:

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[797] See 9 Tr 2613.
[798] See 9 Tr 2618.

> Forecasted benefits may differ significantly from actual realized benefits due to forecasting methods and assumptions. Forecasts only provide the best guess of future performance and cannot serve as evidence of realized benefits. Only actual realized benefits from AMI implementation can demonstrate the ongoing and long-term benefits of AMI technology.[799]

She also disputed that most of the benefits from AMI implementation have already been realized:

> As the Company leverages AMI functionalities, additional operational and customer benefit opportunities will likely arise. For example, since AMI reports customer outages and restorations, the Company has the data to determine the outage durations experienced by customers. It could automatically provide customers with the Electric Reliability Credit, awarded when customers experience long duration or frequent outages, instead of requiring customers to apply for the credits, as is currently required. This could yield greater customer convenience and improved customer service.
>
> The true benefits of AMI do not arise from technology implementation and data collection. They arise from the analysis and use of AMI data to improve Company operations and to improve customer experience. As the Company intends to continue exploring how to leverage AMI data and functionalities, these AMI benefits should accrue over time.[800]

Dr. Wang recommended that DTE provide actual yearly realized benefits of AMI for the categories listed in Exhibit A-19, Schedule 11 "from installation through the rate case year," as well as forecasted benefits from past years to enable comparisons, and future projections.[801]

In her rebuttal, Ms. Robinson objected to Staff's request for additional reporting:

> As noted above, the Company and Staff both agree on the numerous benefits of AMI. However, the amount of data being requested by Staff would require a full-time employee to build a model, mine the data, and continue to report on the data going forward. The Company believes that given the effort involved to produce the data, with no real benefit to show to stakeholders, this would be a non-value added activity. AMI is here to stay,

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[799] See 9 Tr 3359.
[800] See 9 Tr 3361.
[801] See 9 Tr 3362.

> and as noted above, the Company is actively seeking out new ways in which to leverage its investment. In addition to the annual Smart Grid report filed each February in Case No. U-18014, if more "real-time" information is needed by the Staff, the Company is open to sharing its current learnings, operational improvements, and future plans with the Staff or other parties as needed.[802]

Staff argues in its brief that the Commission should continue to require DTE to report on AMI benefits, also citing the RCG's interest in a review of the non-transmitting meter charges.[803] Staff addressed Ms. Robinson's rebuttal testimony:

> The Company's assertion that a full-time staff member would have to be hired to assess the realized benefits of AMI implementation gives Staff concern. If additional Company staff is required to determine the value of AMI programs because the costs and benefits of Company programs are not being tracked, this suggests that the Company is not routinely assessing the success of its programs during implementation that allow course corrections to ensure the most reasonable and prudent use of ratepayer funds. If the Company is routinely tracking the implementation of its programs, their ongoing costs and realized benefits, and providing redirection as needed, then the aggregation of benefits from AMI programs should not require an additional staff member.[804]

DTE rejects Staff's contention that the AMI benefit data would be relevant to an evaluation of the opt-out tariff rates:

> Staff's Initial Brief, pp 120-21, relies on RCG (which again re-hashes its repeatedly-rejected assertions at RCG Initial Brief, pp 13-20) and asserts that the "Company misses the mark" because the additional information regarding "realized AMI benefits" is allegedly needed to "review the validity of the non-transmitting meter charges, as required by the Commission order U-17053." Instead, it is Staff (and RCG) that "misses the mark" because the non-transmitting meter charges are not based on AMI benefits. Instead, they are based on the Staff's own projected costs of those meters: $67.20 to modify the transmitters located inside the AMI meters and for information technology expenses associated with billing, and $9.80 per month to cover the incremental costs of maintaining manual meter-reading infrastructure and of manually reading meters (U-18014, 4 T 578-79). The Commission

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[802] See 9 Tr 2630.
[803] See Staff brief, pages 119-122.
[804] See Staff brief, page 21.

> has repeatedly denied RCG's request to revisit these charges, which will be revisited when AMI installation is complete, as ordered in Case No. U-18014 (see DTE Electric's Initial Brief, pp 63-65).[805]

This PFD finds that DTE should continue to comply with the AMI reporting requirements the Commission has already established, and should work with Staff to make sure that it is not misunderstanding the work involved.

3. Staff Requests Reporting on Charging Forward Pilot

In addition to the discussion above regarding the charging forward program, Staff asked that DTE provide quarterly reports to Staff, and clearly and explicitly state all assumptions regarding EV adoption and charging in the EV grid impact study. DTE did not object to the additional reporting.

4. Other Reporting Requirements

In the discussion above, this PFD recommended that the Commission adopt additional reporting requirements. To summarize: 1) For the reasons discussed in connection with DTE's IT capital expense projections, this PFD recommends that the Commission adopt Staff's IT reporting directions. 2) The ALJ expressed a concern with DTE's capitalization of incentive compensation expenses including duplication of amounts included in rate case O&M as well as incentive compensation categories not authorized for inclusion in rates. The ALJ recommends that the Commission demand a further accounting from DTE and an adjustment to historical rate base. 3) In the context of distribution system capital spending, this PFD recommended that the Commission consider performance-based ratemaking measures for future cases, and that the

[805] See DTE reply, pages 39-40.

Commission require additional reporting regarding DTE's plans to manage its strategic capital investment to avoid displacing those investments with emergent capital and new business expenses. 4) DTE should be required to provide comprehensive information regarding past and expected future CCR costs. 5) DTE should present an updated retirement analysis for Belle River in its next rate case.

X.

COST OF SERVICE

The principal dispute among the parties regarding the cost of service allocations to rate classes involves the production cost allocation method. This is discussed in section A below, with the remaining issues relevant to the cost of service allocations discussed in sections B through E.

A. Production Cost Allocation

Several witnesses addressed DTE's production cost allocation, including Mr. Lacey[806] and Ms. Crozier[807] for DTE, Professor Dismukes on behalf of the Attorney General,[808] Mr. Chriss on behalf of Walmart,[809] Mr. Dauphinais on behalf of ABATE,[810] Mr. Jester,[811] Mr. Boothman,[812] Mr. Gard,[813] and Mr. Bunch[814] on behalf of the MEC Coalition, Mr. Bieber on behalf of Kroger,[815] and Mr. Gottschalk on behalf of Staff.[816]

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[806] See 7 Tr 2034-2047
[807] See 4 Tr 497-503.
[808] See 9 Tr 2841-2858.
[809] See 9 Tr 2663-2664 and 2674-2680.
[810] See 7 Tr 1641, 1652-1654, 1667-1703.
[811] See 9 Tr 3825-3841.
[812] See 9 Tr 3865-3881.
[813] See 9 Tr 3887-3898.
[814] See 9 Tr 3903-3913.
[815] See 8 Tr 2170-2199.
[816] See 9 Tr 3253-3260.

The 4CP 75-0-25 method currently used to allocate DTE's fixed production costs refers to a weighted average allocation based 75% on each rate class's contribution to DTE's system peaks during the four summer months (4CP) and 25% based on total energy use. The Commission adopted the 4CP 75-0-25 production cost allocation method for DTE in Case No. U-17689, subsequent to the enactment of 2014 PA 169 (Act 169).[817] Act 169 required the Commission to initiate a proceeding for each electric utility to evaluate cost allocation and rate design methods used to set rates.[818] In several rate cases since this method was approved, the company and parties representing large commercial or industrial customers have proposed alternatives that would eliminate the energy portion of the allocator and assign costs based 100% on demand. The Commission has rejected these proposals, and in the May 2, 2019 order in Case No. U-20162, pages 128-129, the Commission found:

> DTE Electric's production cost allocation should be revisited in the company's next rate case, which the Commission anticipates may be filed in the very near future. Given the allocation of costs trend since Case No. U-17689, set forth in Exhibit MEC-5, along with the trendline illustrated in testimony on behalf of MEC/NRDC/SC and MEIBC/IEI (6 Tr 2188), the Commission finds it reasonable to revisit this issue to ensure that rates are cost-based, as required by MCL 460.11(1).
>
> For purposes of DTE Electric's next rate case, however, the Commission reminds future parties of the standard:

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[817] Staff correctly points out that, prior to the order in Case No. U-17689, the production cost allocator for DTE was 12CP 50-25-25.

[818] Act 169, MCL 460.11, as originally enacted, mandated, *inter alia*, that "The cost of providing service to each customer class shall be based on the allocation of production-related and transmission costs based on using the 50-25-25 method of cost allocation. The commission may modify this method to better ensure rates are equal to the cost of service." Subsequently, MCL 460.11 was amended to reflect the 75-0-25 allocator that the Commission adopted as part of the Act 169 proceedings, while still permitting the Commission to alter the allocator "if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service."

> that any party proposing to revise the production cost allocation method in a future case include in its evidentiary presentation an analysis using the equivalent peaker method or an approximation for comparison purposes. On pages 52-53 of the NARUC Manual, it states that "[e]quivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added." January 31, 2017 order in Case No. U-18014, p. 100 (alteration in original).

As an initial matter, the MEC Coalition contends that in Case No. U-20162, the Commission's determination that the production cost allocator should be revisited in this case, means that the Commission found that 4CP 75-0-25 does <u>not</u> reflect cost-of-service-based rates. Staff disagrees, arguing that the Commission's desire to revisit the production cost allocation method does not imply that the Commission made a finding that 75-0-25 should be replaced.[819]

A review of the Commission's discussion of the production cost allocator in Case No. U-20162 does not indicate that the Commission determined that 4CP 75-0-25 does not ensure cost-based rates, only that the parties raised sufficient concerns, such that the allocator should be reexamined in the instant proceeding, where additional evidence could be brought to bear on the issue. The ALJ agrees with Staff that had the Commission found that 75-0-25 does not reflect cost-causation, the Commission could have modified the allocator in DTE's last rate case.

Consistent with the Commission's order, the Attorney General, and the MEC Coalition presented alternative production cost allocation methods. Walmart

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[819] See Staff reply, page 27.

recommended another option in the event the Commission decides to change the allocation method. Specifically, the Attorney General proposed to equalize the weighting of the demand and energy portions of the 4CP method, and Walmart recommended the use of an Average and Excess (A&E) method. The MEC Coalition offered three choices for allocating production costs: (1) 4CP Equivalent Peaker (EP4CP) method; (2) Equivalent Peaker Usage (EPU) method; and (3) Probability of Dispatch (POD) method.[820] However, in its brief, the MEC Coalition no longer advocates for the adoption of the POD or EPU methods, instead recommending that the Commission implement the EP4CP method or the Attorney General's proposal for production cost allocation.[821]

In the sections below, this PFD provides an overview of the various methods proposed by the intervenors followed by a discussion of the appropriate production cost allocator based on the record in this proceeding.

<u>4 CP 75-0-25 and Modified Weighting</u>

Mr. Lacey presented the unbundled cost of service (UCOS) studies for DTE in Exhibit A-16, Schedules F1.1 and F1.2.[822] Mr. Lacey explained that for the test year UCOS, DTE proposes to continue to apply the 4CP 75-0-25 allocation method to

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[820] Mr. Jester presented the MEC Coalition's UCOS studies for the three proposed methods in 2nd Revised Exhibit MEC-66. In support of the UCOS studies, "Mr. Boothman partitioned the proposed production costs DTE presented in Exhibit A-16 Schedule F1.1 among the company's generation assets. Mr. Bunch calculated the equivalent peaker costs for each category of DTE's generation assets. Mr. Gard calculated the allocation of costs for each of DTE's plants and other resources using the POD method. Mr. Gard also calculated the share of peaker usage attributable to each customer class using the POD method." MEC Coalition brief, page 76.
[821] MEC Coalition brief, pages 98-99.
[822] Mr. Gottschalk sponsored Staff's UCOS, which also used the 4CP 75-0-25 production cost allocation method, using Staff's revenue requirement, in Exhibit S-6; F1.1.

production-related costs and 12CP 100-0-0 to transmission O&M costs.[823] Distribution costs and customer-related costs were allocated by various methods, consistent with the Commission's approvals in Case No. U-20162.

Mr. Lacey provided an overview of the three-step process (functionalization,[824] classification, and allocation) used to develop a UCOS study, noting that the company included an updated general and intangible (G&I) plant functionalization in the study, per the Commission's order in Case No. U-20162. He also provided sources and methods for functionalization and allocation processes, explaining that he reclassified certain equipment that operates at sub-transmission voltage (24/40 kilovolts(kV)) to properly allocate the associated costs.[825] Based on the company's rate request, DTE will experience a $165.4 million total production revenue deficiency, and a $185.2 million distribution revenue deficiency.[826]

Mr. Lacey testified that the 4CP 75-0-25 method has been approved in DTE's last four rate cases, characterizing it as a "good initial step in appropriately aligning cost allocation and cost causation."[827] Staff also recommended continuing the use of the current allocator,[828] and Mr. Dauphinais testified that although ABATE would prefer a 4CP

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[823] Except for the Attorney General's challenge to the classification of certain facilities as distribution, discussed below, the 12CP 100-0-0 transmission cost allocator was not in dispute.
[824] See, Exhibit A-16, Schedule F1.3.
[825] See 7 Tr 2022-2023.
[826] See DTE brief, page 155.
[827] See 7 Tr 2025.
[828] See Staff brief, page 102. Staff however disagrees with DTE's claim that the 75-0-25 allocator is a "good initial step" toward aligning cost allocation with causation. Citing multiple orders, Staff contends, "The Commission has consistently found that an energy portion for the production allocator is necessary for that allocator to properly reflect the cost to serve customers . . . There is no reason to believe the Commission intended the current production allocation to be a step on the road towards a 100% demand allocation, nor would that be appropriate." Staff reply, page 26.

100 allocator for production costs, it does not contest the continued use of 4CP 75-0-25.[829] Walmart and Kroger also support the current production cost allocation method as discussed by Mr. Lacey.[830]

Professor Dismukes reviewed the history of legislative mandates regarding the production cost allocator from 2008 through 2016.[831] He agreed that the 4CP portion of the allocator was appropriate because DTE is a summer-peaking utility.[832] And he agreed with the Commission's finding, in Case No. U-17689, that DTE's system was built to provide both energy and capacity;[833] thus, the production cost allocator should reflect both total energy use and capacity. Professor Dismukes opined, however, that although the 4CP 75-0-25 method generally comports with the average and peak (A&P) allocation approach, "the arbitrary 75 percent demand and 25 percent energy weighting for classifications does not. It is typically accepted that the weighting between demand and energy components should be equal (i.e. 50-50) or based on the utility's system load factor."[834] Professor Dismukes explained that he evaluated DTE system load factors from 2014-2018, which have ranged from 44.4% to 47.2%, with a 44.4% load factor for the projected test year, which supports his proposed 50-0-50 allocation method.

In addition, Professor Dismukes conducted two analyses of the classification of individual generating units, first by examining the gross plant in service amount of each

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[829] See 7 Tr 1641, 1651-1654.
[830] See Kroger brief, page 6; Walmart brief, page 8.
[831] See 9 Tr 2843-2844.
[832] See 9 Tr 2848; Exhibit AG-2.2.
[833] See June 15, 2015 order, pages 20-23.
[834] See 9 Tr 2849, citing Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners (NARUC Manual) pages 57-59, Exhibit MEC-68.

unit and the unit's projected test year capacity factor. In his second analysis, he again calculated gross plant in service for each unit and then considered the levelized cost of each unit to classify the function that each unit serves. According to Professor Dismukes, "[t]his second analysis can be appropriately viewed as a close facsimile to the equivalent peaker method the Commission has noted in the past."[835] According to Professor Dismukes, the result of the first analysis showed the same 50-50 split between energy and capacity functions as his load factor analysis. The second analysis "finds that, at most, only 59 percent of the Company's production plant in service could be classified as being associated with provision of demand-functions."[836]

Thus, based on his assessments, Professor Dismukes proposed to adjust the production cost allocator to equalize the energy and demand weightings, resulting in a 4CP 50-0-50 allocation. Professor Dismukes explained that his proposal "is based on my analysis of what would constitute a fair and reasonable approximation of the relative cost of service[,]" and is "consistent with examinations of the relative classification of individual Company generation units."[837] If adopted, Professor Dismukes approach would decrease production costs allocated to residential customers by $47.8 million and increase the share allocated to primary customers by $49.9 million.[838]

In its brief, the MEC Coalition notes that the Attorney General's result is quite close to the result from Mr. Jester's EP4CP analysis.[839] The MEC Coalition also points to

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[835] See 9 Tr 2854; Exhibit AG-2.5.
[836] See 9 Tr 2855.
[837] Id. at 2857.
[838] See 9 Tr 2944.
[839] See MEC Coalition brief, page 80.

testimony by Staff witness Charles Putnam, in Case No. U-17689, wherein Mr. Putnam described an analysis he performed to determine if a zero percent energy weighting was reasonable. He found that it was not reasonable and further explained that a 25 percent energy weighting "is the minimum," and it would also be reasonable for the energy weighting to be higher.[840]

In rebuttal, Ms. Crozier testified that the Attorney General's proposal does not result in the cost-based rates required under MCL 460.11,[841] and Mr. Lacey testified that the methods Professor Dismukes employed are not equivalent peaker methods, as the Commission requires for replacing the 4CP 75-0-25 allocation method.[842] Mr. Lacey explained that:

> The NARUC Manual describes two methods to calculate the demand/energy splits for a Company's generating units, under the equivalent peaker method. The first method is based on the original cost to install the Company's generating units. The second method utilizes a comparison of the relative rate base cost of a peaker unit to that of a base load unit with the assumption that the relative average cost difference determines the percentage of base load unit should be considered demand-related. Exhibit AG-2.5 determines the demand/energy split in two ways: method 1 uses capacity factors and method 2 compares a levelized total cost to the MISO CONE price. Neither method utilizes either original installation cost or a comparison of the rate bases of base load and peaker units. Therefore, I do not see how this is a "close" approximation.[843]

Mr. Bieber also took issue with Professor Dismukes' recommendation, noting that although there are some structural similarities between the 4CP 75-0-25 method and the A&P method, "the utilization of total peak demand [in the A&P method] is different than

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[840] Id. at 71, quoting Case No. U-17689 at 2 Tr 316-317. The ALJ took official notice of Mr. Putnam's testimony and exhibits from Case No. U-17689. See 4 Tr 110-111.
[841] See 4 Tr 503.
[842] See 7 Tr 2047.
[843] Id.

some other energy weighted cost allocation methods, like the Average and Excess ("A&E") method, which uses an *excess* demand measure to allocate capacity costs."[844] Mr. Bieber testified that the portion of the NARUC Manual Professor Dismukes relies on does not support the energy weightings that he proposes, and he opposed using the system load factor to compute energy weighting in the A&P approach, explaining that because this method includes average energy for all hours of the year, including peak periods, it results in a bias against higher-load factor customers.[845] Mr. Bieber therefore recommended that the Commission reject Professor Dismukes proposal, reasoning that:

> [T]he NARUC Manual prescribes a specific weighting calculation for the P&A method which would actually result in a 69.5% peak demand weighting and 30.5% energy weighting. Therefore, Mr. Dismukes' proposed 4CP 50-0-50 method would actually be a further departure from the P&A method, compared to the current and proposed 4CP 75-0-25 method.
>
> Further, cost allocation methods such as the 4CP 75-0-25 and the P&A already suffer from a structural bias that double weights the energy component and unreasonably shifts costs towards higher load factor customers.[846]

<u>Average and Excess Method</u>

As noted above, Mr. Chriss testified that for the purposes of this docket, Walmart does not oppose the continuing use of the 4CP 75-0-25 method for production cost allocation; however, if the Commission decides to make a change, he stated that it would be more appropriate to use an A&E method for allocating these costs.[847]

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[844] See 8 Tr 2175.
[845] See 9 Tr 2177-2179; Figure KRO-1.
[846] See 8 Tr 2181-2182.
[847] See 9 Tr 2675.

According to Mr. Chriss, an A&E allocator:

> recognizes the contribution of each class to average demand, as well as the relative non-coincident peak ("NCP") demand of each class. The class NCP value is subdivided into average demand and excess demand.
>
> The average demand, which represents the energy portion for each class and is calculated by dividing the kWh for each class by 8760, is weighted by the system load factor. The excess demand portion, which is the difference between the average demand and NCP demand for each class, is weighted by 1 minus the system load factor.
>
> As system load factor increases, the weighting of the average demand portion of the allocator increases. That is, as the system load factor increases, more weight is given to the energy portion of the allocator. Additionally, as a class load factor increases, the allocator for that class reflects an increase in the weight given to the energy portion of the allocator. At a theoretical maximum of 100 percent load factor, the A&E allocator is essentially an energy allocator. As such, this methodology recognizes production plants as being used to meet peak demand as well as provide energy.[848]

Mr. Gottschalk took issue with a number of Mr. Chriss's characterizations, noting that, contrary to Mr. Chriss's understanding (that the production cost allocator allocates *capacity* costs), "[t]he 4 CP 75-0-25 method allocates production costs associated with generation plants other than fuel whether they are related to provision of capacity service or not."[849] According to Mr. Gottschalk, Mr. Chriss's use of the term "production capacity cost allocation" coupled with equating capacity costs with "fixed generation costs" might lead one to assume that all production costs are capacity- (e.g., demand-) related, and therefore "should be allocated strictly on a demand basis with no energy component."[850]

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848 Id. at 2678-2678.
849 See 9 Tr 3254.
850 Id. at 3255.

Mr. Gottschalk testified that some production costs are incurred to provide lower-cost baseload energy and therefore should not be considered capacity-related.

Mr. Gottschalk explained that while the Staff does not necessarily oppose the A&E method, it nevertheless prefers retaining the current 4CP 75-0-25 method, which assigns the majority of costs to peak demand while still recognizing that energy must be provided reliably year-round.[851]

Equivalent Peaker 4CP Method

Mr. Jester explained that because DTE was unable to provide production costs by individual plant, the MEC Coalition witnesses used categories of plants (i.e., Fossil, Nuclear, Hydraulic, Peakers, MISO, and PPA) for the methods he used in his analysis. "In addition, we allocated certain cost pools not associated with energy or capacity resources in the cost of service study, namely Other, Transmission, and General/Intangible." Mr. Jester added that, "while our results using plant categories are not as precise as if done by individual plant, they are based on the same categories that DTE uses in its cost of service study and should be about equally accurate as their results."[852]

According to Mr. Jester, the EP4CP method:

> partitions total production costs for the utility's energy and capacity resources between energy and capacity, by identifying the cost of capacity with the sum of the current costs of a peaker of equivalent age and capacity for each of the utility's resources, then subtracting that sum from total production costs to identify energy costs. Energy costs are then allocated to customer classes based on an appropriate energy usage metric and

[851] Id. at 3258.
[852] See 9 Tr 3828.

> capacity costs are allocated to customer classes based on an appropriate measure of usage of capacity.[853]

As shown in 2nd Revised Exhibit MEC-66, line 17, a change to the EP4CP method for production cost allocation would reduce the revenue requirement for the residential and commercial secondary classes by $42.2 million and $1.2 million respectively, and it would increase the revenue requirement for the primary class by $41.8 million and result in an increase of $1.6 million for lighting classes.

Ms. Crozier testified that all three methods proposed by the MEC Coalition should be rejected as contrary to MCL 460.11. DTE maintains that, "[t]o reverse course now would erode a decade of deliberate, and legally-required, moves intended to ensure that rates are equal to the cost of service."[854] In addition, Mr. Lacey testified that in the company's UCOS, not all production costs are allocated, only those that are plant and plant-related. "Other production costs are allocated on a different basis or directly assigned. For example, fuel expenses are allocated 90% on energy and 10% on 12CP."[855] Contrary to DTE's approach, Mr. Lacey claimed that Mr. Jester allocated all production costs in all three of his analyses. In doing so, Mr. Lacey asserted that the MEC Coalition "totally ignored the capacity charge calculation mandated by the Commission and created its own inappropriate methodology."[856]

Mr. Lacey testified that using the correct capacity charge calculation method, he recalculated Mr. Jester's UCOS in Exhibit MEC-66 in Exhibit A-36, Schedule AA1.

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[853] Id. Nevertheless, in the company's next rate case, the MEC Coalition recommends that DTE be required to provide production costs on a plant-specific basis.
[854] See DTE brief, page 158
[855] See 7 Tr 2037.
[856] Id. at 2043.

According to Mr. Lacey, "[i]ncorporating the Commission mandated capacity charge calculation into MEC Witness Jester's proposed EP4CP method results in a $42 million reduction to primary customers and a $42 million increase to residential customers as compared to the Company's filed COSS in this proceeding."[857]

The MEC Coalition responds that MCL 460.11(1) does not require that the same costs that are used for the capacity cost calculation under MCL 460.6w must also be used for the production cost allocator. As for DTE's Exhibit A-36, Schedule AA1, which purportedly adjusted Mr. Bunch's calculation of EP required revenue, the MEC Coalition responds:

> *Of course* that result is surprising – because the method made no sense. The calculation of capacity charge required revenue is made by subtracting certain costs listed in the 6w statute from the sum of all production costs. The calculation of equivalent peaker required revenue is made by adding together all of the production costs for DTE's peakers and segregating those from the production costs for DTE's baseload fleet. Substituting the capacity charge revenue requirement for the revenue requirement for the peakers and reallocating based on the capacity charge number is a pointless exercise, because the two sets of costs have nothing to do with each other.[858]

Nevertheless, in its brief, the MEC Coalition states that it does not oppose applying the EP4CP method to just the Section 6w capacity charge costs. "The point is that doing so is not required by the statutes and it may not reduce the costs relief to residential customers."[859]

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[857] Id. at 2044.
[858] MEC Coalition reply, page 40.
[859] MEC Coalition brief, page 95. The MEC Coalition also points out that DTE's fuel cost allocation method, which allocates 90% of costs on the basis of energy, actually allocates more costs to large industrial customers than the method Mr. Jester used.

Staff agrees with the MEC Coalition, that there is no relationship between the production cost allocation method and the capacity charge calculation, arguing, "[a]ny given production allocator will have no effect on the capacity charge revenue requirement, as the capacity charge revenue requirement uses total production costs, which do not change based on how that total is allocated to each class. Therefore, the Commission should not be influenced by any discussion of the capacity charge . . . as support for the Company's arguments regarding production cost allocation."[860]

Mr. Bieber also took issue with the MEC Coalition's EP4CP method, contending that Mr. Boothman's plant assignments were erroneous because many of the plants included in the fossil and peaker categories do not have similar operating characteristics. He pointed out that some of the plants included in the peaker category have higher capacity factors than others assigned to the fossil category.[861]

Like Mr. Lacey, Mr. Bieber testified that the MEC Coalition's EP method differed from the standard method described in the NARUC Manual. According to Mr. Bieber:

> According to the NARUC Manual, the ideal analysis is a "date of service analysis." In the example above from the NARUC Manual, the ratio of the cost of a new combustion turbine compared to the cost of a new coal unit is 30%. Thus, 30% of the rate base for all of the example utility's coal-fired and other generation units of varying ages is classified as demand-related, and the remainder is classified as energy-related.
>
> In contrast, Mr. Bunch's modified peak classification compares the average revenue requirement of all of the units that Mr. Bunch categorized as "Peaker" units to the average revenue requirement of the rest of DTE's generation resources. The use of revenue requirement by generation category skews the results of this analysis because it includes non-capital costs, such as fuel expense, which varies based on the relative usage of

[860] Staff's reply brief, pages 27-28.
[861] 8 Tr 2184-2185.

> each category of generation resource. Further, it does not take into consideration the varying ages of the different generating units and the results are further skewed by the varying levels of depreciation. Thus Mr. Bunch's use of the relative revenue requirements between generation categories does not provide an "apples to apples" comparison of investment costs for the various generation alternatives or provide an accurate representation of the trade-off between fixed and variable costs.[862]

Mr. Bieber further testified that there were historical reasons why the EP classification method is not appropriate, explaining that between 1978 and 1987, the use of natural gas, and therefore the construction of peaker units, was restricted by the Powerplant and Industrial Fuel Use Act. He noted that DTE's Monroe, Belle River, Fermi and Ludington pumped storage plants were planned and built at a time when natural gas supply was disrupted, thus:

> [E]lectric utilities could not just as easily install natural gas fueled combustion turbines as other technologies. Thus, the premise underlying the Equivalent Peaker method that utilities would only incur costs for more expensive units because of additional energy loads is not consistent with the historical generation planning practices during the timeframe when the majority of DTE's production plant was being planned.[863]

The MEC Coalition contends that Mr. Boothman assigned DTE's plants to the same categories that DTE and the Staff did. The MEC Coalition adds that the use of average revenue requirement in its EP4CP analysis tends to skew the results more toward demand than energy because DTE's peaker units are generally newer than its baseload units, a point that Mr. Bieber conceded in cross examination. Finally, the MEC Coalition points out that the peaking units that DTE installed in the 1960's, before any natural gas supply disruptions, were miniscule in both size (12.5 MW to 60-160 MW) and

[862] 8 Tr 2186-2187.
[863] Id. at 2189.

installed cost ($100-$200 per MW), compared to the Monroe and Fermi units.[864] According to the MEC Coalition:

> The suggestion that difficulties constructing 12 or 100 MW peakers for $100 per kW played any significant role in DTE's decision to build the massive Monroe and Fermi plants for more than $1,000 per kW strains plausibility to the breaking point. When pressed for specific evidence that gas supply issues or the Fuel Use Act played a material role in DTE's decisions to build Monroe or Fermi, Mr. Bieber acknowledged he was not aware of any. He acknowledged the same thing with respect to Ludington. He also conceded that DTE would have planned and developed Monroe before the issues he surmised about would have commenced in the early 1970s.[865]

Equivalent Peaker Usage and Probability of Dispatch Methods

Mr. Jester described the EPU method as "very similar to the Equivalent Peaker 4CP Method, except that the Equivalent Peaker Required Revenue is allocated proportional to customer class shares of peaker usage[.]"[866] Noting that because peakers are not used exclusively in the summer months, Mr. Jester testified:

> The peaker usage method looks beyond the theory that peaker capacity is needed to serve system peak and looks empirically at when peakers are actually needed. Peakers may be needed because of seasonal performance characteristics of other generating units, periods of outage of non-peaking resources for maintenance, and many other reasons. The actual usage of peakers reflects that the overall system is relatively short of capacity resources and must therefore dispatch units that are expensive to run. It would therefore be appropriate to allocate peaker costs to the times when they are actually operating.[867]

Under the EPU method, as shown in 2nd Revised Exhibit MEC-66, page 1, line 27, the revenue requirement for residential and commercial secondary customers would

[864] MEC Coalition brief, page 92.
[865] Id., citing 8 Tr 2228-2230, 2231, 2234.
[866] See 9 Tr 3832.
[867] See 9 Tr 3836-3837.

decrease by a total of $166.3 million while the revenue requirement for primary customers would increase by $162.1 million

For the POD method, Mr. Jester explained:

> The probability of dispatch method allocates all costs, whether plant, fuel, or other operating costs on a common basis. The total revenue requirement for each plant is allocated to its hourly usage over the year, typically based on MWh of net generation. Costs allocated to each hour from each plant are summed for each hour, reflecting that all customers are served by the pooled energy from all plants. Costs for each hour are then allocated to each customer class in proportion to the customer class usage of energy in that hour and such hourly allocations are summed over the year. This method allocates the cost of baseload plants to customers based on their use throughout the year, the cost of load following plants to customers based on their loads during "on-peak energy hours," and the cost of peakers to the customers using energy during periods of relative generation shortage that cause dispatch of plants such as peakers that have high marginal costs.[868]

Mr. Jester opined that with the addition of wind, solar, and storage to DTE's system, "unless the Commission changes to a marginal cost method for all costs, it will eventually be necessary to use the probability of dispatch method or a similar method to properly allocate costs to customer classes based on the varying roles of various generation resources in meeting electricity demand at various times."

Application of the POD method for allocating production costs would decrease residential revenue requirement by $157 million, and decrease commercial secondary revenue requirement by $35.6 million, while increasing the revenue requirement for primary customers by $185.5 million.[869]

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[868] See 9 Tr 3829.
[869] 2nd Revised Exhibit MEC-66, page 1, line 36.

Several parties criticized the EPU and POD methods, including DTE, Staff, ABATE, Kroger, and Walmart. DTE points out that the POD method is a time-differentiated approach, and not an equivalent peaker method, and that there were several errors in Mr. Boothman's assignment of revenues. In general, Staff disagreed with Mr. Jester's claim that the POD method may be required in the future if the Commission does not change to a marginal cost method for all costs. Mr. Gottschalk testified that Mr. Jester failed to support his claim, and he did not demonstrate that embedded cost methods do not properly allocate costs.[870] Kroger asserts:

> MEC's proposed Probability of Dispatch and Peaker Usage allocation methodologies suffer from logical inconsistencies that should disqualify them from approval by the Commission. DTE's generation participates in the MISO market and is dispatched based on MISO system conditions, which are not always aligned with DTE's system conditions. DTE can also rely on resources owned by other parties to serve its loads. Given this disconnect between DTE system loads and the dispatch of DTE's generation resources, Mr. Bieber concluded that the Probability of Dispatch and Peaker Usage allocation methodologies do not accurately match the dynamic nature of DTE's generation costs to the variability of DTE customers' loads.[871]

Discussion

Highlighting Professor Dismukes' testimony, the Attorney General maintains that DTE's significant rate increases have fallen disproportionately on residential ratepayers, noting that the revenues collected from the residential class have increased by 34.9% since Case No. U-15244, whereas revenues from primary customers have decreased by 24.5% in the same time period. The Attorney General largely attributes this disparity to

[870] See 9 Tr 3254.
[871] See Kroger brief, pages 11-12 (footnote omitted).

the company’s COSS methods, particularly its approach to allocating production costs which “ha[s] a material impact on customer rates, skewing results away from actual cost of service rates and placing a higher burden on smaller usage customers.”[872] Consistent with this view, the Attorney General advocates the adoption of Professor Dismukes’ proposed 4CP 50-0-50 method as a reasonable and fair approximation of cost of service for residential and primary customers. Alternatively, if the Commission declines to adopt his proposal, Professor Dismukes recommended that the rate increase for residential customers be limited to 1.15 times the overall average increase, with any shortfall allocated to the remaining customer classes.[873]

The MEC Coalition asserts that the same production cost allocation issues that the Commission cited in its order in Case No. U-20162 continue to exist, citing Exhibit MEC-61, which shows an increasing disparity in rate increases for residential customers compared to industrial customers. In addition, the residential class’s share of production costs has increased from 40.1% to 50.7%, with a commensurate decrease in costs borne by the primary class from 36% to 24.4%, from the beginning of Case No. U-17689 to the present case.[874]

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[872] See Attorney General brief, pages 121-122.
[873] See Attorney General brief, page 113.
[874] The MEC Coalition notes that “DTE may take the position that the “apples-to-apples” production cost allocator shares in this case are instead 47.1755% for the residential class and 27.8896% for the primary class, based on Mr. Lacey’s workpaper. If so, MEC-NRDC-SC-CUB accept those numbers. Whether the increase in the allocation of production costs to the residential class in this case is 1% or 4%, it results in a large monetary cost shift due to the very large amount of revenue involved. Based on Mr. Lacey’s Exhibit A-16, Schedule F1.5, p 1, column (a), line 1, DTE’s total net production costs revenue requirement is $3,277,653,000, so a 1% change in the allocator shifts almost $33 million in costs.” MEC Coalition brief, page 82 (footnote omitted).

The MEC Coalition further contends that DTE's production costs are heavily weighted toward base load generating plants, which were designed and built to provide large amounts of energy at a low variable cost, principally for the benefit of primary customers. Nevertheless, about half of the company's production costs are paid for by residential customers, who use only 35-36% of the energy that DTE supplies.[875] Finally, the MEC Coalition contends that the 4CPEP method it proposes ensures that rates are equal to cost of service because it mirrors the approach used in integrated resource planning where, "the required revenue for any nonpeaking resource is earned as the cost of a peaking resource of the same net capacity plus the sum over all times of the marginal cost of energy when it is dispatched."[876] For these reasons, the MEC Coalition recommends that the Commission adopt a production cost allocator more heavily weighted toward energy such as its proposed 4CPEP method or the Attorney General's proposed 4CP 50-0-50 weighting.

As noted above, DTE, Staff, ABATE, Kroger, and Walmart recommend that the Commission continue the use of the 4CP 75-0-25 method for allocating fixed production costs. DTE maintains that the Attorney General's recommendation of 4CP 50-0-50 does not result in cost-based rates, as required under MCL 460.11. Moreover, DTE contends that Professor Dismukes' approach, which relies on system load factors, is not an approximation of an EP method that the Commission requires for replacing the current

[875] See MEC Coalition brief, page 83.
[876] Id., quoting 9 Tr 3836.

allocator. DTE also argues that Professor Dismukes' proposal to limit any residential rate increase to 115% of the overall system average rate increase would be unlawful.

Regarding the MEC Coalition's recommendations, DTE claims that the proposals are "deeply flawed" for numerous reasons and should therefore be rejected.[877] DTE reiterates that under all three methods, the MEC Coalition incorrectly calculated the capacity charge, pointing out that although the coalition contends that it was not intending to calculate the capacity charge, "there is no meaningful difference between 'capacity charge' and 'revenue requirement attributable to capacity'"[878] in the MEC Coalition's presentation.

DTE also asserts that the MEC Coalition incorrectly allocated several tax categories including income tax, social security tax, and property tax, and that its calculation of G&I costs was erroneous. "Overall, MEC/NRDC/SC/CUB ignores the reality that these errors, in the aggregate, total tens of millions of dollars and unpersuasively suggests that their erroneous conclusions should be ignored because they are partially offset by other amounts that were also calculated incorrectly."[879] Finally, DTE argues that the MEC Coalition's approach, allocating revenues to each rate class rather than assigning them directly, is unsupported by its witnesses and the NARUC Manual.[880]

ABATE first takes issue with the Attorney General and MEC Coalition's citation to testimony and documents in other proceedings, contending that reliance on such information is contrary to MCL 24.285 and that the Commission must rely on the record

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[877] See DTE reply brief, page 90.
[878] Id. at 91.
[879] Id. at 92.
[880] Id. at 93.

in this case as the basis for its decision. ABATE adds that the Attorney General and the MEC Coalition's evidence and arguments in this proceeding constitute a collateral attack on prior Commission orders.

ABATE maintains that differences in rate increases or decreases across customer classes does not demonstrate that rates are not cost-of-service based. To show that rates are not cost-based, the Attorney General would need to demonstrate that the facts and circumstances underlying the Commission's decision to implement the 4CP 75-0-25 method have materially changed, such that an alternative production cost allocator is justified. ABATE argues that the Attorney General has failed to make this showing, noting:

> [W]hen performing rate comparisons, and when considering the production facility cost allocation methodology specifically, it is important to isolate production facility costs from other costs in rates. (7 Tr 1682.) Without doing so the rate comparison provides no insight into whether production facility costs and their allocation are appropriately driving overall customer class rate increases. (Id.) This is because overall base rates include both power supply and delivery service costs, while power supply costs alone include certain non-production facility when performing rate comparisons, and when considering the production facility cost allocation methodology specifically, it is important to isolate production facility costs from other costs in rates. (7 Tr 1682.) Without doing so the rate comparison provides no insight into whether production facility costs and their allocation are appropriately driving overall customer class rate increases. (Id.) This is because overall base rates include both power supply and delivery service costs, while power supply costs alone include certain non-production facility costs that are not allocated to customers using the production facility cost allocator.[881]

Next, ABATE argues that the facts underlying the Commission's decision in Case No. U-17689 have not materially changed, "[i]ndeed, DTE's minimum kW hour to

[881] See ABATE reply brief, pages 45-46 (footnote omitted).

maximum kW hour percentage (resulting in the Company's hour load analysis) and the dollar portion of DTE's production assets that are base load remain extremely similar."[882] Thus, according to ABATE, a change from 4CP 75-0-25 is not justified.

ABATE takes issue with the Attorney General's claims that the 75-0-25 portion of the allocator is arbitrary or that an equal weighting of energy and capacity is a more generally accepted approach to production cost allocation. ABATE contends that the current allocator was the result of careful consideration and that the NARUC Manual does not indicate that a 50-0-50 weighting was prevalent. ABATE further asserts that using an overall system load factor, typically 50%, "pre-ordains" a 50% weighting of the energy portion of the allocator.[883] In addition, ABATE argues that the Attorney General's analysis contains numerous flawed assumptions, particularly the belief that high load factor customers fully benefit from lower fuel costs, thereby justifying the assignment of more fixed production costs on the basis of energy.[884]

ABATE also contests the MEC Coalition's recommendations, noting that application of the EPU or POD method would result in "an extreme reallocation of costs between the various customer classes and have not been shown to better align costs with their causation."[885] Concerning the EP approaches specifically, ABATE notes numerous flaws in the coalition's methods and arguments in support thereof. ABATE is particularly

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[882] Id. at 47.
[883] Id. at 49.
[884] Id. at 52-53.
[885] Id. at 57.

critical of the MEC Coalition's reliance on the PFD in DTE's previous electric rate case as well as its description of the cross-examination of Mr. Dauphinais in this case.[886]

Relying on the testimony of Mr. Bieber, Kroger contends that the Commission should reject the proposals by the Attorney General and the MEC Coalition on grounds that these methods give too much weight to the energy allocator, to the detriment of high load factor customers. Walmart asserts that if the Commission does decide to modify the production cost allocation method, it should consider adopting an A&E approach to production cost allocation.

As noted above, as provided in MCL 460.11(1), a change from 75-0-25 requires a finding by the Commission that "that this method of cost allocation does not ensure that rates are equal to the cost of service." The MEC Coalition and the Attorney General contend that the disparity between residential and industrial rates has continued to grow, as has residential customers' share of production costs. In addition, DTE's production costs are heavily weighted toward baseload plants, primarily Fermi and Monroe, which the MEC Coalition contend provide the most benefit to industrial customers.

ABATE counters that 75-0-25 does ensure that rates are equal to the cost of providing service, and that differences in rate increases for residential versus industrial customers are insufficient to demonstrate that the allocation method is unreasonable. According to ABATE, "The degree to which each rate class is affected by a revenue requirement increase is a function of the type of cost that is increasing and how each rate

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[886] Id. at 64-65.

class contributes to that cost."[887] ABATE further notes that an overall rate comparison "provides no insight into whether production facility costs and their allocation are appropriately driving overall customer class rate increases[,]"[888] pointing out that base rates include revenue requirements for both production and distribution costs. Finally, ABATE concludes that:

> The Commission relied on Staff's analysis in that [U-17689] proceeding, stating that it "well supported" the 75-0-25 methodology which "better ensures rates are equal to cost of service." . . . Updated for current conditions, this foundational analysis demonstrates that the facts and circumstances underlying the Commission's determination have not changed. (See 7 Tr 1686-88; Exhibit AB-30; Exhibit AB-31.) Indeed, DTE's minimum kW hour to maximum kW hour percentage (resulting in the Company's hour load analysis) and the dollar portion of DTE's production assets that are base load remain extremely similar. (*Id*.) In fact, the minimum portion of production facility assets that should be allocated on total energy is actually less now than the figure calculated in Case No. U-17689. (*Id*.) As such, there is no evidence that there has been a change since Case No. U-17689 to either the characteristics of DTE's load or the dollar portion of its production assets that are base load which would justify increasing the portion of production facility costs currently allocated to customer classes on the basis of total energy. (*Id*.)[889]

The MEC Coalition no longer advocates for the adoption of the EPU or POD methods, instead recommending that either Professor Dismukes' proposed 4CP 50-0-50 allocator or the EP4CP method be adopted. The Attorney General recommends that Dr. Dismukes' suggestion to equalize the peak and energy weightings in the current allocator be approved.

Although the MEC Coalition made a reasonable first attempt at implementing the EP method, the PFD nevertheless agrees with DTE that, given the number of errors in its

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[887] See ABATE brief, pages 44-45.
[888] Id. at 45.
[889] Id. at 47 (footnote omitted).

analysis, the results are not sufficiently reliable to approve in this proceeding. Although DTE's claim, that only the costs included in the calculation under Section 6w should be included in the EP4CP method, should be rejected for the reasons discussed by the Staff, DTE nevertheless points to a number of other problems with the MEC Coalition's approach. These issues include the incorrect allocation of certain taxes, the erroneous calculation of G&I costs, and the failure to directly assign revenues rather than allocate them. As DTE points out, these errors could result millions of dollars in production costs that are misallocated. In addition, the MEC Coalition's analyses were hampered by the fact that DTE could not provide revenue requirements by plant. As for this last point, the PFD agrees that DTE should be directed to provide this information in its next rate case.

Turning to the Attorney General's recommendation of a 50-0-50 allocation of production costs, as an initial matter, the PFD disagrees that the Commission intended that the EP method, and only the EP method, could be presented as an alternative to the current allocator. In its discussion in the January 31, 2017 order in Case No. U-18014, pages 100-101, the Commission found that "the equivalent peaker method is <u>one</u> method that may provide additional beneficial information about production cost allocation." (Emphasis supplied). Thus, Professor Dismukes' approach, looking at the relative weighting of the peak and energy portions of the allocator based on system load, is a reasonable one, even though it is not strictly an EP approach. That said, this PFD finds that Professor Dismukes' claim, that a 50-0-50 allocation is typical, was not well supported. Nevertheless, Professor Dismukes' load factor analysis as refined by Mr. Bieber, along with Mr. Putnam's testimony in Case No. U-17689 that a 25% energy weighting is a minimum in production cost allocation, provides sufficient support to demonstrate that 75-0-25 should be modified to slightly increase the energy weighting to 30% and decrease the demand weighting to 70%.

B. Subtransmission

The Attorney General recommended that the Commission adopt a 12CP 100-0-0 cost allocation methodology for subtransmission plant facilities, consistent with the allocation of transmission plant. According to Professor Dismukes: "This would [reflect] the quasi-transmission role sub-transmission plays in the delivery of electric power."[890] Professor Dismukes described DTE's subtransmission system which consists of lines and transformers between 24 and 120 kV, noting that:

> The presence of 120 kV lines on the Company's sub-transmission system is unusual, as voltages greater than 115 kV are usually associated with bulk transmission systems, and indeed MISO defines bulk electric system as facilities "generally operated at voltages of 100 kV or higher." The presence of high-voltage lines on the Company's sub-transmission system reflects the quasi-transmission role sub-transmission plays in the delivery of electric power.[891]

DTE disagrees with the Attorney General's recommended allocation of subtransmission facilities, noting that transmission plant is allocated based on the same 4CP 75-0-25 allocation as production plant. DTE contends that the Attorney General confuses the allocation of transmission plant with transmission O&M, which is allocated on 12CP 100-0-0. Pointing to rebuttal testimony by Mr. Lacey, DTE argues:

> Mr. Dismukes' proposal should be rejected because it essentially re-functionalizes subtransmission plant from distribution to power supply, as 12CP 100-0-0 is a power supply allocator (7T 2036). Mr. Dismukes attempted to support his proposal based on the claim that "the Company's

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[890] See 9 Tr 2861.
[891] Id. at 2860 (footnote omitted).

> 120 kV lines, which comprise approximately 1.9 percent of the Company's sub-transmission system in mileage, are certainly closer in characteristic to transmission systems than the Company's distribution system" (9T 2860). In addition to the AG's proposal being based on just a small percentage of lines, the Commission previously recognized why 120 kV lines are on the Company's system, and specifically adopted the Company's undisputed classification proposal that "classifies distribution facilities to include the 120 kV radial lines to end-use customers as well as facilities operating at lower voltages (41.6, 24, 13.2 and 4.8 kV and secondary voltages)." (January 14, 1998 Opinion and Order in Case No. U-11337, p 3. See also, p 8). There is no basis to revisit this previously-established matter (7T 2036-37).[892]

In her reply brief, the Attorney General responds that DTE's argument is misleading because, "Dr. Dismukes' reference is to the allocation of DTE Accounts 352 and 353, which are Transmission Structures and Improvements and Transmission Station Equipment[,]"[893] adding:

> Dr. Dismukes' proposal would make the Company's allocation of Accounts 355, 356, 357, and 358 consistent with its allocation of 352 and 353.114 These are accounts associated with transmission poles and fixtures and transmission lines (overhead and underground). The Company has not explained why there is an inconsistency in its allocation of these accounts compared to accounts 352 and 353, if all accounts represent sub-transmission plant as now claimed by the Company.[894]

In her reply brief, the Attorney General introduces a new justification for Professor Dismukes' recommendation, providing DTE with no opportunity to respond or explain the alleged inconsistency in the FERC accounts. Moreover, as DTE explains, the company's classification of subtransmission as distribution has been settled since at least 1998. Based on the record in this case, there is no reason to change the current classification of DTE's subtransmission system.

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[892] DTE brief, page 162.
[893] See Attorney General reply, page 32, citing FERC Uniform System of Accounts, 18 CFR 101 pages 469-470.
[894] Id.

C. Secondary Voltage Demand-Related Costs

To allocate costs associated with secondary-voltage distribution plant facilities, DTE uses an allocation method based on the sum of individual customer's peak demand requirements, in contrast to the company's method for allocating costs associated with other demand-related distribution plant facilities, which are allocated on the basis of class non-coincident peak (NCP). Professor Dismukes recommended that costs associated with demand-related secondary-voltage distribution systems also be allocated based on class NCP demands. According to him, "[t]he Company's proposed allocation places too much emphasis on individual customer peak loads failing to recognize that not all customers present on the system peak at the same time. Furthermore, allocating secondary-voltage distribution costs in a manner consistent with the allocation of primary-voltage distribution costs is consistent with how these costs are typically allocated in other jurisdictions."[895]

Professor Dismukes provided an overview of how distribution systems are designed and operated as part of the overall electric grid and explained that although DTE has not assessed the diversity of load profiles on its secondary voltage distribution system, other utilities have done so and have found significant variability in customer load profiles. Professor Dismukes further testified that:

> I have examined eighteen rate cases filed from the period 2010 to 2018. In 66.7 percent of cases the accepted CCOSS allocated costs associated with demand related secondary-voltage distribution plant on an identical basis to costs associated with demand-related primary-voltage distribution plant

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[895] See 9 Tr 2865.

assets. Likewise, in 72.2 percent of accepted CCOSS, the allocation of secondary-voltage distribution plant was based on identified class NCP.[896]

DTE responds that the Attorney General's recommended change is not "necessary or appropriate."[897] Citing rebuttal testimony by Mr. Brasil, DTE maintains that "Mr. Dismukes' recommendation was not robust (18 general rate cases over an eight-year period, out of hundreds of rate cases during that period), and just because a method is used by another utility or in another state does not, in itself, justify its use for DTE Electric."[898] DTE argues that Professor Dismukes did not present sufficient evidence to support any change from the current allocation method.

In her reply brief, the Attorney General defends her position, arguing that DTE's response was simply to dismiss Professor Dismukes' recommendation without providing any evidence supporting its statements in rebuttal.[899]

The PFD finds that while the Attorney General's recommendation may have merit, there is insufficient evidence on this record to support her proposed change in the method for allocating secondary-voltage distribution plant. As the company points out, 18 rate cases out of the hundreds that may have been filed over a decade is a very small sample that may have been biased toward a particular outcome. Nevertheless, the Attorney General may raise this issue in a future rate case, albeit with more evidentiary support for her position.

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[896] See 9 Tr 2864.
[897] See DTE brief, page 162
[898] Id.
[899] See Attorney General reply, page 34.

D. Distributed Generation

The MEC Coalition raises a concern about how energy outflows from DG systems are addressed in the company's COSS. According to Mr. Jester, DG outflows should be treated as negative load and assigned to the customer class that supplies the outflow energy, otherwise, the principal of cost-causation will be violated. Nevertheless, the MEC Coalition admits that DG outflows are extremely small at the present time and therefore will not affect rates established in this case. However, over time, DG may become more prevalent and should be appropriately addressed in future rate cases.[900]

Staff witness Revere disputed Mr. Jester's proposal, testifying that:

> First, until the problem is actually shown to exist, no solution is necessary. Second, Staff does not agree that outflows should offset the allocation of the assets of the voltage level to which the DG customer is connected. While currently it may be the case that outflow likely travels a short distance on the system level to which the customer is connected, at higher levels of penetration that will not necessarily be the case. As admitted by MEC/NRDC/SC/CUB witness Jester, at current levels of penetration the impact of enacting his proposal is not material. At the levels of penetration it would become material, outflow may well travel much farther on the system level to which the customer is connected, and should therefore not offset the inflows on that level of the system. Third, it is not clear from MEC/NRDC/SC/CUB witness Jester's proposal how exactly the offset would occur. In Staff's opinion, any such offset would need to be that which reflects the actual mitigation of the relevant determinant used to calculate the allocators. For these reasons, MEC/NRDC/SC/CUB witness Jester's proposal is flawed, premature, and not fully described or supported, and should therefore be rejected in the instant case.[901]

In its response, DTE points to testimony by Mr. Brasil indicating that the company does not currently have systems that incorporate outflows in calculating load factors, but

[900] See MEC Coalition brief, pages 99-101, see also 9 Tr 3823-3825; Exhibit MEC-64.
[901] See 9 Tr 3399-3400.

DTE will investigate including outflows in determining allocation factors in the company's next rate case.

This PFD agrees with Staff that issues concerning the allocation of DG outflows are premature and should be addressed in the future when DG outflow amounts are sufficient to affect cost allocation.

E. Capacity Charge Revenue Requirement

There is no dispute among the parties regarding the calculation of the capacity charge revenue requirement.

XI.

RATE DESIGN AND TARIFFS

The primary differences between DTE and Staff regarding rate design are driven by different revenue requirement analyses, which are discussed above. The remaining disputes primarily revolve around DTE's residential pilot program proposals, which are addressed in section E below.

A. Residential Rate Design

Soulardarity asks that the Commission freeze residential rates. It argues that DTE's proposed rate increase for residential customers is unfair. It cites the recent history of residential rate increases, and its concern regarding differential investments in infrastructure (discussed above). In evaluating DTE's revenue requirements, this PFD has come to the conclusions as stated above that some of the increase DTE is requesting is unwarranted and made an alternate recommendation accordingly. Nonetheless, this PFD does not recommend that the Commission reject any increase. As DTE and Staff point out, such an approach is inconsistent with the cost of service and rate design principles the Commission has adopted.

Similarly, Professor Dismukes recommended that if the Commission does not adopt his recommended changes to the cost of service allocations, residential rate increases should be limited to 1.15 times the overall system average increase. This PFD discussed cost of service allocations above. Consistent with the discussion of Soulardarity's request, the Commission's choice of cost of service allocations generally determines the revenues to be collected from each class, rather than using rate design to indirectly address cost of service allocations.

The only other disputed issues related to residential rate design involve DTE's proposed pilot programs, which are discussed in section D below.

B. Commercial and Industrial Rates

There are no significant disputes between the parties regarding commercial and industrial rate design. Staff proposed a correction to DTE's initial allocation of property taxes in determining the customer charge; DTE and Staff now agree the currently-approved customer charges for sub-transmission and transmission customers should be retained and the customer charge for primary customers should be increased to $70.

Citing Mr. Zakem's testimony, the Foundry Association of Michigan argued that DTE's proposed service charge increases were unjustifiably high for subtransmission and transmission voltage customers.[902] Staff addressed these concerns in its reply brief, explaining that DTE did not initially follow Staff's method, and as noted above, Staff's

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[902] See Foundry Association brief, pages1-3.

recommended customer charges for subtransmission and transmission voltage customers are the same charges approved in Case No. U-20162:

> Staff's customer charge method, which is the same method used by Staff in DTE's last three cases, uses principles that apply to all customer classes, not just residential and commercial secondary. Exhibit S-6, Schedule F-1.4 details the steps in the calculation and produces customer charges for residential, commercial secondary, primary, sub-transmission and transmission customers.
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> In its continued debate against the Company's customer charges and the method used, the Foundry Association of Michigan and Energy Michigan fail to recognize Staff's revelation that the "Staff method" used by the Company is not actually the method used by Staff in this case or in previous cases. (9 TR 3249.) They also ignore the Company's admission to the same and subsequent recommendation in its rebuttal testimony to adopt Staff's proposed customer charges for primary, sub trans and transmission customers. (7 TR 2047-2048.)[903]

As Staff argues, Staff's rate design is cost-based and appears to resolve the dispute.

C. Streetlighting

Soulardarity also objected to the differential rate increases for above ground and underground streetlighting rates. Mr. Koeppel testified to Soulardarity's concerns:

> DTE is increasing rates for streetlights with above-ground wiring disproportionally as compared to streetlights with below ground wiring. DTE estimates the above-ground wiring increase to be approximately 11.0%. See Exhibit A-16, schedule F3, page 44 (line 112, column (j) ($22,781) compared to line 112, column (f) ($20,523)). DTE estimates the increase for underground as approximately 2.3%. See Exhibit A-16, schedule F3, page 46 (line 120, column (j) ($25,658) compared to line 120, column (f) ($25,083)); see also Exhibit A-16, Rate Schedule No. E1 (Municipal Street Lighting Rate) (defining "Underground Municipal Street Lighting").
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> Financially-struggling communities comprised of low-income people, like Highland Park, have less financial resources due to a low income-tax base and more urgent other needs, e.g. public safety, social safety-net expenditures, etc. Thus, raising rates more steeply on overhead-wired

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[903] See Staff reply, page 28.

fixtures relative to underground-wired fixtures creates a disproportionate impact on the lower-income communities.[904]

Staff and DTE explained that the cost allocations drive the rate increases, and consistent with the established cost of service allocation and ratemaking principles, the charges for each of the lighting rates are designed to collect a revenue requirement based on actual cost.[905] Nonetheless, this PFD recommends that in its next rate case, DTE provide an explanation of efforts it has taken to control the costs of maintaining aboveground streetlighting as well as any efficiencies gained through the use of technology.

D. Distributed Generation Tariff (Rider 18)

DTE proposed to continue the outflow credit for Rider 18, set at power supply less transmission, which is the same method the Commission approved in Case No. U-20162.[906] Several intervenors raised concerns regarding distributed generation generally, and the DG tariff specifically. On behalf of GLREA, Mr. Rafson testified that Rider 18 is unreasonable and unfair to DG customers. Mr. Rafson raised issues with respect to the inflow/outflow method, claiming that there is insufficient data to properly calculate the outflow credit. He recommended that a detailed COSS be undertaken "which considers all relevant costs, savings, and benefits associated with DG."[907]

Mr. Rafson testified that the inflow/outflow compensation mechanism is not reasonable, again because of a lack of data about each individual DG customer, the

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[904] See 6 Tr 1415-1416.
[905] See Isakson, 9 Tr 3142-3143.
[906] See 7 Tr 2126-2127.
[907] See 9 Tr 2780.

timing of netting for TOU DG customers versus Rate D1 DG customers, the failure to account for the capacity value provided by DG, the failure to incorporate the value of avoided air emissions and pollution, and the different values assigned to inflow and outflow without any justification, among other concerns. Given these unaddressed issues, Mr. Rafson suggested that the Commission return to the monthly net metering approach under Rider 16, "until such time as a comprehensive cost of service study and data can be provided to determine the impact on rate recovery and the customer's rate as well as the cross subsidy that the DG customers provide to all other customers."[908] Mr. Rafson further observed that whatever value DG provides to DTE, credits to DG customers should not vary based on system size.

Mr. Richter echoed Mr. Rafson's concerns, testifying that Rider 18:

> dramatically increased the cross-subsidy from DG customers to other customers in their class. Under the DG tariff, outflow is credited at roughly half of the retail rate, without any basis from the cost-of-service study. Nor has a study of the effect of instantaneous netting been commissioned.[909]

Mr. Richter added that DTE's DG program, as currently designed and implemented, violate Bonbright principles 4, 5, and 8. Specifically, according to Mr. Richter, the DG tariff does not discourage the wasteful use of electricity; it does not reflect the present and future private and social cost of electric service, and Rider 18 does not promote innovation in response to changing supply and demand patterns.[910]

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[908] See 9 Tr 2784.
[909] See 9 Tr 2796.
[910] See 9 Tr 2796-99, citing Edison Electric Institute, "1.0 Primer on Rate Design for Residential Distributed Generation", February 14, 2016, at 9 Tr 2797 n10.

DTE responds that the Commission approved Staff's method for calculating the outflow credit in Case No. U-20162, and the company used the same calculation here. DTE points out that the outflow credit does recognize the value of capacity because it includes both capacity and non-capacity rates for power supply. Staff also disagreed with GLREA's position, noting that the power supply component of the outflow credit includes pollution control expenses. "Therefore, the suggestion that the Company is not compensating DG for offsetting these items is incorrect."[911] Staff also takes issue with the suggestion that DG customers be placed in a separate class and that placing each DG customer into his or her own class is "unreasonable and inappropriate."[912] Finally, Staff points out that it is completely appropriate to treat systems of significantly different sizes differently.

While some of GLREA's concerns are well-taken, Rider 18 has been in effect for less than one year, and most, if not all, of the arguments GLREA raises here were considered in the Commission's evaluation of the DG tariff as part of company's last rate case. Accordingly, this PFD finds that GLREA's request to revisit and modify Rider 18 should be rejected at this time.

Next, Staff and GLREA recommend that the company voluntarily lift the 1% "soft" cap on distributed generation. Mr. Matthews testified that based on data from net metering reports, DTE may reach the cap for smaller generators (20kW or less) between 2021 and 2023. Mr. Matthews explained that because Rider 16 is now closed and Rider

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[911] See Staff brief, page 88.
[912] Id. at 89.

18 is based on inflow/outflow, a cost-based pricing mechanism, “limiting aggregate participation to the PA 295 soft caps is no longer necessary.”[913] Mr. Matthews pointed out that the Upper Peninsula Power Company has doubled the DG cap to 2% pursuant to a settlement agreement.

In response, DTE contends that the cap is set by statute, and in any event, until DG rates include a system access charge, they are not cost-based. As such, it would be unreasonable to increase the cap because doing so “could expose the Company to uncapped revenue shifts, and expose non-DG customers to increased and improper cost subsidizations.”[914]

The Commission has previously determined that Rider 18, without a system access charge, is cost-based, contrary to the company’s claims.[915] As for limitations on DG participation, MCL 460.1173(3) provides: “An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years.” Thus, the characterization of this portion of the statute as a cap, soft or not, is misplaced because Section 73(3) only sets a lower limit, leaving the upper boundary to the utility’s discretion. As such, the Commission cannot order DTE to allow more participants in the program once the 1% amount is reached. Nevertheless, DTE should be mindful of the interplay

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[913] See 9 Tr 3268.
[914] See DTE brief, page 182.
[915] As Staff points out, Rider 16 is a closed, legacy net metering program that is not cost-based. However, going forward, all new participants will be required to apply to the program under Rider 18, which is cost-based.

between the company's self-imposed 1% limit on the DG program and the Commission's determination in Case No. U-20471, the company's recent IRP:

> The Commission finds that a DG analysis is imperative for IRPs. The Commission finds that the pace of changes in technology and customer behavior in this area demands that DTE Electric not screen out DG in its next IRP filing. The company's rationale that DG resources are not dispatchable or schedulable is unconvincing, as the same could be said for other elements of a modern electric grid. Similarly, its arguments over cost seem to ignore the investments customers have made in these systems, and focuses only on utility-owned DG resources. The Commission directs the company to fully analyze the effects of DG on the company's plan in its next IRP filing.[916]

Finally, Mr. Jester suggested that customers in DTE's SolarCurrents program be allowed to remain on Rider 16 for the twenty-year term of the SolarCurrents contract.[917] This issue is currently being addressed in a complaint case, Case No. U-20657, and need not be resolved here.

E. Pilot Programs

1. Fixed Bill Pilot

DTE proposed a Fixed Bill pilot as "an elective offering that allows up to 5,000 residential customers to pay a prespecified fixed monthly amount for a period of one year that is not subject to any adjustments for actual usage or price."[918] This pilot will be offered to customers, taking service under the residential rate schedule D1, "who have been in their current residence over the previous 12 months and are currently in good financial standing with the Company."[919] Mr. Clinton testified:

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[916] See February 20, 2020 order in Case No. U-20471, page 62.
[917] 9 Tr 3853-3855.
[918] See 6 Tr 1011.
[919] See 6 Tr 1011 and 6 Tr 1029.

> The Company will use the customer's historical monthly usage and the weather of that region to estimate usage under normal weather conditions, apply a forecasted usage change, and then bill that usage at the residential rate, plus a risk premium. At the end of each contract year, the Company will re-estimate each customer's offer for the next year, and each customer would then decide whether to renew. The Company plans to utilize an experienced vendor to calculate the forecasted usage change and risk premium.[920]

The vendor will determine the usage charge and risk premium based on experience with other Fixed Bill programs. The usage charge will "range from 0% to a maximum of 5%" and the risk premium will "range from 5% to a maximum of 10%."[921] Renewal in the program will be automatic, unless the customer withdraws.[922] Under what he labeled the "reasonable usage clause," a customer may be terminated from the Fixed Bill pilot when "actual usage in a given month is 30% greater as compared to . . . the previous year, excluding the effects of weather."[923] Mr. Clinton testified: "DTE Electric will implement this provision when feasible, after programming and modifications to the customer billing system have been made."[924] DTE intends to begin enrollment in the program in January 2021 and continue for 18 months.[925] The company projects costs for this pilot to be $2,800,000; with O&M expenses of $900,000 per year and capital spending for IT investments of $1,200,000.[926]

DTE will not impute a loss to other customers and indicated if the risk premium consistently exceeds costs, the excess could reduce the revenue requirement for the

[920] See 6 Tr 1028.
[921] See 6 Tr 1028.
[922] See 6 Tr 1032.
[923] See 6 Tr 1034.
[924] See 6 Tr 1030.
[925] See 6 Tr 1068.
[926] See 6 Tr 1067-1068.

residential rate class.[927] The PSCR and other surcharges would be funded based on each customer's actual monthly usage, rather than forecasted usage. Mr. Clinton also testified that DTE intends the usage clause to deter customers from taking advantage of Fixed Billing, stating it would only be used during the pilot if higher usage was widespread.[928] Mr. Clinton testified that DTE is not proposing a "true up" adjustment based on actual usage if a customer is removed from the program.[929] However, a "true up" will be done if the customer withdraws from the program prior to the end of the year, unless that customer moves from the service location.[930] And, the customer who leaves the program will not receive any credit if payments exceed what would the customer would otherwise have paid if not in program.[931]

In Case No. U-20162, the ALJ rejected a similar fixed bill pilot "on grounds that, more likely than not, the effects of the program would be contrary to the energy conservation policy goals of the State of Michigan and the company's energy efficiency efforts."[932] The Commission held:

> Given the valid concerns raised by the Staff, the Attorney General, and MEC/NRDC/SC; the various rate options already available to customers; and the forthcoming roll-out of the new summer on-peak rate, as further discussed below, the Commission does not find . . . the company's proposed pilot programs to be reasonable or prudent at this time.[933]

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[927] See 6 Tr 1028-1029.
[928] See 6 Tr 1030
[929] See 6 Tr 1032. Staff objected to a "true up" when a customer is removed from the program in Case No. U-20162.
[930] See 6 Tr 1032-1033
[931] See 6 Tr 1033
[932] See Proposal for Decision, Case No. U-20162, page 246.
[933] See May 2, 2019 order, Case No. U-20162, page 144.

The Commission cited with approval the ALJ's proposed decision in that case,[934] which also found:

> 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.[935]

Mr. Clinton acknowledged the Commission's decision in that case rejecting DTE's proposal, but contended in this testimony that objections from multiple parties in Case No. U-20162 were due in part to "an incomplete understanding of Fixed Billing and the consumer benefits that it delivers" and asserted changes were made to the Fixed Bill pilot to address Staff and intervenor concerns.[936] He testified that the pilot DTE proposes "will validate what, if any changes in usage will occur for customers" on the program.[937]

Mr. Clinton disagreed that the fixed billing would negatively impact price signals ("customers' price clarity or sensitivity to electric pricing") because DTE will consider their annual consumption in making a renewal offer, and because "[c]ustomers will continue to see current month actual usage charged and compared to the same month last year."[938] He drew an analogy to car insurance:

> An analogy can be made with auto insurance. With auto insurance, renewal offers reflect increases attributable to vehicle accidents, speeding tickets, and claims, so consumers are incentivized to engage in safe and lawful

[934] *Id.*
[935] See Proposal for Decision, Case No. U-20162, page 247
[936] See 6 Tr 1012.
[937] See 6 Tr 1017.
[938] See 6 Tr 1018.

> driving. In the case of Fixed Bill, the same incentive exists for the subsequent plan term, so energy conservation in this period rewards consumers with lower bills in their next term.[939]

Although asserting it is speculative to assume peak usage will increase under the program, Mr. Clinton admitted "utility benchmarking has found Fixed Bill's impact on peak demand varies from little or no impact to some impact, reiterating the need for a pilot."[940]

Mr. Clinton also disputed that the program duplicates the BudgetWise program, which "allows customers to pay a fixed monthly amount that is trued up annually and adjusted quarterly based on actual usage."[941] Nonetheless, Mr. Clinton presented the results of a 2018 survey which showed "roughly 55% of Fixed Bill customers would come from BudgetWise billing."[942] He asserted, "[f]ixed Billing is a reasonable and prudent extension of BudgetWise billing that provides valuable risk management features to a potentially large number of customers who like bill certainty and are currently under-served."[943] Mr. Clinton also stated low-income customers would benefit because they would be protected from a "true up" under the Fixed Bill pilot. In his view, "Customer desires and preferences, in this case should be provided an equal, if not greater consideration in supporting this pilot."[944] Also in support of the proposed pilot, Mr. Clinton presented examples of states that have adopted fixed bill programs with supporting documentation in Exhibit A-27.

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[939] See 6 Tr 1016.
[940] See 6 Tr 1019.
[941] See 6 Tr 1011.
[942] See 6 Tr 1027.
[943] See 6 Tr 1019-1020.
[944] See 6 Tr 1019.

Finally, Mr. Clinton testified that Arcadia Power, a third party, is offering Fixed Billing program which is similar to its proposed pilot and “appear to be soliciting business” from DTE customers. Mr. Clinton stated that because Arcadia is not regulated by the Commission this created a lack of transparency and oversight which is not in the best interests of customers and is unfair to DTE.[945] Mr. Clinton testified Arcadia is a growing company, however, he could not provide specific data on the number of customers in its territory, if any, who are enrolled with Arcadia.[946]

Staff, the Attorney General, and several intervenors recommend the Commission reject the fixed bill pilot. These parties argue that the fixed bill pilot is contrary to the State of Michigan’s energy conservation goals.

Mr. Isakson testified that the pilot “enables consequence free usage increases.”[947] He explained his concerns:

> The Company goes to great lengths to attempt to show that customers are unlikely to increase consumption, either energy or demand, when enrolled in a fixed bill program. However, the Company proposes to rely on a vendor to estimate customers’ fixed bills that include a forecasted usage change between 0% and 5%. This is in direct contrast to the Company’s residential sales forecast. The Company estimates that residential sales will decrease by an average of 0.4% annually through the test year. If the Company expects overall residential consumption to decrease yet plans to build in a projected increase in consumption for fixed bill customers, then it follows that the fixed bill program is directly opposed to energy conservation efforts. Because the fixed bill pilot assumes that customers increase usage under the program then either the Company actually expects customers to use more and sets the fixed bill appropriately, or the Company expects customers usage to remain unchanged, yet charge based on higher calculated usage. If customer consumption matches the estimated increase, then it violates the assumption that energy conservation goals are preserved under a fixed bill program. If the customer does conserve energy,

[945] See 6 Tr 1024.
[946] See 6 Tr 1025.
[947] See 9 Tr 3130.

> then the Company will continue to bill the customer as if they made no change. In either case, the fixed bill pilot program fails to address the Commission's concerns about the Company's previous fixed bill proposal.[948]

Mr. Isakson disputed Mr. Clinton's car insurance analogy, explaining that DTE customers can choose not to enroll in the fixed bill program following a year of high consumption, but most drivers will need to purchase car insurance.[949] Addressing DTE's assertion that conservation is not the only consideration in designing a new pilot, and its reference to other pricing programs such as interruptible rates and senior citizen discounts, Mr. Isakson countered that energy conservation should not be excluded from consideration and notes "those other pricing programs . . . do not so thoroughly mask price signals."[950] He also addressed DTE's contention that customers desire this service, explaining that customer demand "is not enough on its own to justify the existence of a rate" and stated the Commission must consider the reason for the rate "beyond customer desire."[951] Noting that a third-party vendor will "effectively calculate an estimated bill for each customer,"[952] Mr. Isakson stated the fixed bill pilot is not appropriate even if information can be gleaned, because the program itself "erodes the Commission's ratemaking authority."[953] He explained that DTE's proposal that it will not impute a loss under the fixed bill proposal and will "assume that . . . customers paid sufficient revenue at approved

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[948] See 9 Tr 3129-3130.
[949] See 9 Tr 3131.
[950] See 9 Tr 3131.
[951] See 9 Tr 3132.
[952] See 9 Tr 3134.
[953] See 9 Tr 3135.

rates," would in effect "decouple revenue from standard Commission-approved rates by way of estimating customer usage without reconciliation."[954]

Mr. Isakson also addressed DTE's reliance on Arcadia, testifying that Arcadia is not a regulated utility and therefore not subject to the Commission's ratemaking authority, and not relevant to an evaluation of DTE's proposal.[955] He also testified that DTE did not provide any evidence that its customers, or any consumers in Michigan, have signed up for any service from Arcadia, and thus have not established any negative consequences.[956]

Mr. Coppola also found DTE's proposal basically the same as its proposal in Case No. U-20162. He expressed his primary concern that the program will likely "discourage energy conservation."[957] He did not find DTE's proposal to notify customers about their current usage or its potential impact on their offer in the following year sufficient to address this concern: "Instead, such warnings could create confusion and resentment."[958] Mr. Coppola addressed Mr. Clinton's reference to Arcadia, testifying that Arcadia mainly markets renewable energy and that the company's website does not mention fixed billing, characterizing Mr. Clinton's concerns as overstated.

Mr. Jester objected to the proposal. He testified: "With the exception of the change in the reasonable usage clause, the Fixed Bill proposal in this case is not materially

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[954] See 9 Tr 3134.
[955] See 9 Tr 3134.
[956] See 9 Tr 3133-3134.
[957] See 9 Tr 3061.
[958] See 9 Tr 3061-3062.

different"[959] than proposals put forth by DTE in prior cases.[960] He disputed that fixed billing sends clear price signals to customers, characterizing any signal as "muted." Mr. Jester further pointed to DTE's plans "to offer fixed bills based on a projected consumption increase of up to 5%, at a time when residential electricity usage in DTE service territory has not been growing materially" and DTE is not projecting growth.[961]

Addressing DTE's reasonable usage clause, he characterized it as an improvement on the prior plan, but concluded the program is still "likely to increase energy consumption, mute price signals, and supplant a portion of the BudgetWise billing program."[962] Mr. Jester also noted that DTE relies on the same survey that was criticized in Case No. U-20162, and does not consider that customer demand resolves the concerns with the program. Recommending that the Commission disapprove the program, Mr. Jester also testified that DTE should consider revisions to the BudgetWise billing program.[963]

To Mr. Koeppel, DTE's proposal represented an interesting idea that could provide a helpful option for low-income customers, but objected that the program "does not appear to be well designed to achieve that stated goal and needs significant restructuring."[964] Mr. Koeppel asserted the pilot should include "only low-income

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[959] See 9 Tr 3845.
[960] See MPSC Order in Case No. U-17054, December 20, 2012 and MPSC Order in Case No. U-20162, May 2, 2019. In Case No. U-17054, the Commission rejected a fixed bill pilot in an *ex parte* case and ordered the matter be addressed in a contested case.
[961] See 9 Tr 3845. Mr. Jester points to Ex A-15, Schedule E1 for the assertion that DTE is not projecting per household growth.
[962] See 9 Tr 3848.
[963] See 9 Tr 3850.
[964] See 6 Tr 1418.

customers and should be coupled with energy-efficiency programs."[965] Mr. Koeppel expressed concern that higher income customers, who are more able to pay utility bills, will use more energy under this pilot and asserted consumers seem to use more power when they know their bills are going to be the same.[966]

Mr. Koeppel expressed a concern whether the program would benefit low-income customers, given its exclusion of customers taking service under the D1.6 residential tariff.[967] He also expressed a concern that low-income customers would pay more under this program. He observed that fixed bill customers are going to have higher bills due to the risk premium.[968] He pointed out, "customers might not be aware that they are paying a premium for fixed billing services relative to the standard rate."[969] And, he argued the risk premium should be expressly capped if the pilot program is adopted,[970] some notice should be required before a customer is removed from the program, and any overpayments from the fixed bill program should be returned to those customers."[971]

Mr. Isakson presented rebuttal testimony addressing Mr. Koeppel's testimony in part, emphasizing that Staff agrees with Mr. Koeppel's concerns regarding the pilot's shortcomings, but recommends that the pilot be rejected rather than revised.[972]

In his rebuttal testimony, Mr. Clinton reiterated the positions he presented in his direct testimony. He disputed that program runs contrary to conservation goals, insisted

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[965] See 6 Tr 1401.
[966] See 6 Tr 1419. Mr. Koeppel pointed to Mr. Clinton's testimony and Ex A-27, Schedule R1.1 when addressing increased usage.
[967] See 6 Tr 1420-1421.
[968] See 6 Tr 1420
[969] See 6 Tr 1422
[970] See 6 Tr 1422
[971] See 6 Tr 1423-1425
[972] See 9 Tr 3145.

that a pilot is the only well to determine whether consumption or peak consumption would increase, contended that Staff's rejection of the program fails to acknowledge customer benefits in the form of budgeting and potentially reduced billing inquiries, disputed that the program would interfere with the Commission's ratemaking, reasserted his concern with Arcadia, opining that DTE estimates 1100 customers have enrolled, and highlighted what he believes are significant differences between this program and the program rejected in Case No. U-20162. He also disputed that the program duplicates the BudgetWise billing program, disputed that the program could cause customer confusion, and reiterated in response to Mr. Koeppel's concern that DTE's risk premium under the program is capped at 10%, while also acknowledging that the program is not targeted to low-income customers.

This PFD finds the fixed bill pilot should be rejected by the Commission for the same reasons the Commission rejected the program in Case No. U-20162. That is, as the ALJ found in that case, "more likely than not, the effects of the program would be contrary to the energy conservation policy goals of the State of Michigan."[973] The fixed bill pilot proposed in this case is substantially the same as was proposed in Case No. U-20162. Mr. Isakson's testimony is persuasive that the program does not send proper price signals. As he pointed out, DTE's proposed pilot includes a projected increase in consumption of up to five percent each year, which is in direct opposition to energy conservation goals.[974] DTE's benchmarking does not refute energy conservation

[973] Proposal for Decision, Case No. U-20162, page 246.
[974] See 9 Tr 3129.

concerns. Mr. Clinton admitted the utility benchmarking showed varying impacts on peak demand.[975] And the unregulated activities of Arcadia, whatever they may be, do not justify the approval of a program that is contrary to the interests of ratepayers as a whole or contradicts the policy of the State of Michigan.

2. Low-Income Renewables Pilot

DTE proposed the Low-Income Renewables program (LIRP) as a pilot program to enable low-income customers to participate in the company's MIGreenPower program (MIGP) and increase the percentage of renewable energy they use. Mr. Clinton testified that customers qualified for this program "will be provided 35% incremental renewable energy . . . at no additional cost."[976] The program will permanently retire RECs and credit participating customers with renewable energy for 50 percent of their usage.[977] This pilot program "will be designed to enroll up to 2,500 qualified customers."[978] Qualified customers are "at or below 200% of the federal poverty level, who are not enrolled in Low Income Self Sufficiency Program (LSP), Shutoff Protection Program (SPP), or any other low-income credit program and are less than $100 in arrears."[979] DTE confirmed that 240,000 of its customers are at or below 200 percent of the federal poverty level, and with the above limitations, only approximately 56,000 customers will be eligible to participate in LIRA.[980] DTE projects the proposed total costs for the LIRP to be $800,000; with

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[975] See 6 Tr 1019.
[976] See 6 Tr 1037.
[977] See 9 Tr 3855.
[978] See 9 Tr 1038.
[979] See 9 Tr 1037-1038.
[980] See 6 Tr 1114.

$250,000 for Marketing and Customer Acquisition, $300,000 for IT Infrastructure development, and $250,000 for the RECs to be retired.[981]

Staff, the Attorney General, and several interveners argued this program should be rejected by the Commission as proposed. Mr. Banks testified the LIRP "pilot, as currently designed, doesn't attempt to aid low-income customers in lowering their electric bills, or the rates that they pay."[982] In his view: "The only direct benefit from this program appears to be that the Company can demonstrate that it is investing in the low-income community and that it has a renewable energy program for [those customers]."[983] Mr. Banks recommended that DTE work with the RE and EWR sections of the MPSC to create a new program to provide actual benefits to low-income customers, and file a new proposal in the next rate case.[984]

Mr. Koeppel testified the LIRP "investments in IT and marketing are disproportionate relative to the investments in renewable energy credits [which represent] just 31% of the total Pilot spending."[985] Mr. Koeppel testified: "The program eligibility requirements needlessly limit which low-income customers can participate in the pilot and undermines DTE's claim that the purpose of the pilot is to learn more about the demand of low-income consumers for renewable energy."[986] He points out that many low-income customers rely on other programs. "The fact that less than 25% of DTE's customers below 200% of the federal poverty line could participate in this pilot shows that DTE has

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[981] See 9 Tr 3855.
[982] See 9 Tr 3193.
[983] See 9 Tr 3194-3195.
[984] See 9 Tr 3195-3196.
[985] See 6 Tr 1435.
[986] See 6 Tr 1432.

not structured the pilot in a manner necessary to gain information about the interests of a broad swath of DTE's low-income consumers."[987] Mr. Koeppel also noted the pilot simply allocates or retires RECs from existing wind and solar facilities, and does not provide for the development renewable energy resources in low-income communities.[988]

Mr. Jester questioned the plan to cap low-income customer's participation in renewable energy to 50 percent of usage and suggests the LIRP be modified to allow qualified customers the option for up to 100 percent renewable energy.[989] And, Mr. Jester stated he did not see a public policy basis for limiting the LIRP and excluding other low-income program participants.[990] And, Mr. Jester suggested the Commission require DTE to report on the progress of the LIRP every six months, and the Commission require DTE to file additional options to provide economic benefits to customers in the next Voluntary Green Pricing (VGP) program case.[991] MEC asserts the LIRP should only be approved with Mr. Jester's proposed modifications.[992]

Mr. Kenworthy commended DTE for recognizing the need for a low-income renewable pilot, but objected to the pilot DTE proposed. Mr. Kenworthy expressed a concern that the program serves "mostly a marketing purpose," noting that DTE's witness supporting the program is from the regulated marketing department. Mr. Kenworthy noted his general concerns with DTE's VGP program as explained in DTE's recent IRP case,

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[987] See 6 Tr 1433-1434.
[988] See 6 Tr 1432.
[989] See 9 Tr 3856.
[990] See 9 Tr 3856.
[991] See 9 Tr 3856.
[992] See 9 Tr 3859.

Case No. U-20471.[993] Mr. Kenworthy also testified the LIRP program lacks "additionality" because it will only retire RECs from existing renewable facilities:

> No new renewable energy resources will be added to the DTE system to provide this capacity. New programs should lead to the development of new resources, not simply repurposing of existing resources. As previously noted, the Company is already recovering the costs of those resources through its PA295/PA342 programs, and it is appropriate to continue that recovery. But new resources should be developed for any proposed low-income renewables program so that those customers can capture the benefits of new clean energy resources.[994]

In his view, low-income customers should be put in a position where they can benefit from the falling costs of renewable energy and see bill savings.[995] He testified:

> For generations, low-income communities and communities of color have disproportionately borne the health burden and received less of the economic benefits of the United States' centralized fossil fuel-based energy system. While the Company's proposal marginally increases access to clean energy for low-income customers, the proposal will not result in any bill savings. Rather, it is just an accounting mechanism on that provides no financial benefit and that does nothing to address energy burden or provide additional low-income benefits.[996]

Mr. Kenworthy provided information regarding alternative program designs. He also expressed a concern with the size of the pilot and its exclusion of customers participating in other programs, narrowing the group of eligible customers.[997] He recommended the Commission not approve the program and that DTE work with stakeholders to improve the program.

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[993] See 9 Tr 2734.
[994] See 9 Tr 2734-2735.
[995] See 9 Tr 2735.
[996] See 9 Tr 2735-2736.
[997] See 9 Tr 2736-2737.

In his rebuttal testimony, Mr. Clinton testified that DTE does consider the provision of renewable energy as DTE has proposed to be a direct benefit to customers, and indicated that DTE also plans to offer addition renewable energy pilots or programs to customers.[998] He welcomed the opportunity to work with Staff, but wants to be able to offer the pilot.[999] Mr. Clinton responded to Mr. Kenworthy's concerns, contending that as a component of the MIGreenPower program, the pilot would satisfy "additionality".

This PFD finds that the proposed Low-Income Renewables pilot (LIRP) should be rejected as proposed. DTE has not shown the pilot will benefit low-income consumers. First, the program does not provide for new renewable generation resources; DTE will retire RECs from facilities operating at the time MIGP was approved.[1000] Second, exclusion of a majority of low-income customers indicates the program is not structured to efficiently glean information about the interest in renewable energy by the majority of the low-income customers.[1001] Third, the program does nothing to aid low-income customers to lower their bills. And fourth, the costs for the program are disproportionally marketing costs; purchase of RECs is less than a third of the total amount requested by the company.[1002] This PFD recommends that DTE accept Staff's offer to work with Staff's Renewable Energy and EWR sections, and also work with stakeholders, to redesign a low-income renewables pilot that offers more tangible benefits to low-income customers.

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[998] See 6 Tr 1060.
[999] See 6 Tr 1061.
[1000] 9 Tr 2729-2730
[1001] 6 Tr 1433-1434
[1002] See 6 Tr 1129. Mr. Clinton admitted the costs of this pilot maybe higher than others.

3. LIA Pilot/Low-Income Energy Assistance Initiative

Ms. Johnson testified that the goal of DTE's energy assistance program is "to gradually reduce arrears owed, while encouraging and supporting good payment habits and reducing consumption."[1003] She explained DTE's Low Income Self Sufficiency Program (LSP), in which DTE works with eligible customers, allowing them to make affordable fixed monthly payments with the remainder paid through energy assistance funds. She explained the eligibility criteria:

> A customer's income must be equal to or less than the 150% Poverty Level Guidelines (FPL). In addition, the customer's energy consumption cannot exceed $1,600 for electric, $2,150 for gas, and $3,750 for combined accounts. A customer's account must be active and less than $3,000 of arrears at time of enrollment.[1004]

Income eligibility is determined by evidence the customer is receiving a Home Heating Credit or through confirmation by a State or federal agency. She explained that customers in the LSP program get the LIA credit of $40 per month, as well as Michigan Energy Assistance Program (MEAP) funds. She views the LSP program as successful, testifying that less than 1% of the participants were disconnected for non-payment, while customers who receive the LIA credit but are not in the program have a 7% disconnection rate. LSP program participants take service under DTE's Residential Service Special Low-Income Pilot tariff, Rate Schedule D1.6, which was approved in Case No. U-17767. Ms. Johnson testified that DTE would like to expand the eligibility for the Residential Income Assistance Credit so that Rate Schedule D1.6 customers are eligible for that

[1003] See 6 Tr 1138.
[1004] See 6 Tr 1136.

credit as well. And she testified that DTE would like to increase funding for the LIA credit from $15.4 million to $24 million "to accommodate a projected increase of customers enrolled in the 2020 LSP."[1005] With the additional ratepayer funding, DTE would give preference to LSP customers, and "[n]on LSP customers who meet the LIA credit eligibility requirements will be considered for funding after all available LSP customers have been enrolled onto the credit."[1006]

Mr. Colton testified on behalf of the Attorney General and the MEC Coalition. Mr. Colton described his 35-year background working on low-income utility issues, including the planning, implementation, and evaluation of bill assistance programs for low-income households. He discussed his evaluation of DTE's programs, beginning with an examination of the affordability of energy to low-income customers in DTE's service territory, addressing the impact on DTE's collection outcomes due to its lack of an adequate bill assistance program, and then recommending changes to DTE's initiatives. While Mr. Colton's testimony is too detailed for a summary to do it justice, he assessed affordability by looking at the "income deficit" between annual incomes DTE low-income households experience and the income that would be needed to meet minimum levels of "self-sufficiency," and also by looking at the relationship between total housing costs, including utility costs, and income in DTE's service territory. He explained:

> As home energy takes up an increasing proportion of total housing costs, there is less money remaining to pay for the housing component of total shelter costs. As a result, DTE households are either forced into increasingly lower-priced (and presumptively lower quality) housing, or those households face ongoing bill payment problems attributable to the

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[1005] See 6 Tr 1142.
[1006] See 6 Tr 1142.

> mismatch between household resources and household expenses. In either case, the very housing cost characteristics that contribute to payment difficulties of DTE electric customers make it less likely that the household will be able to avoid those payment difficulties.[1007]

Mr. Colton also explained his conclusion that providing adequate bill assistance to low-income customers will help improve payment outcomes for DTE, "creating correspondingly positive impacts on reducing the costs associated with nonpayment that are ultimately charged to ratepayers."[1008] He reviewed DTE-specific data, and provided his opinion that DTE does not collect all the data that it should collect as a matter of prudent industry practice:

> DTE was unable to provide in a timely fashion certain information about the relationship between usage and payment difficulties that the utility should have readily accessible. This data includes the number of customers receiving bills for current service, the dollars billed for service, the dollars received in payments, or the numbers of payments received; the distribution of usage for all residential customers to the distribution of usage for all residential customers in arrears without a one-month lead time; data on the average bill for current service for all residential accounts, the average arrears of residential accounts in arrears, or the average bill for current service of residential accounts in arrears without a one-month lead time; or data disaggregated geographically regarding bills, payments or arrears without a one-month lead time.[1009]

From the data he was able to review, Mr. Colton concluded:

> While there are substantially more disconnect notices than there are actual service disconnections for nonpayment, the number of residential accounts losing service due to nonpayment ranged from a low of 8,018 in December 2018 to a high of 25,865 in October 2018. In this 16-month period, there were three months where DTE disconnected service for nonpayment to more than 20,000 residential accounts and twelve months where DTE disconnected service to more than 12,000 residential customers.[1010]

[1007] See 9 Tr 3661.
[1008] See 9 Tr 3661.
[1009] See 9 Tr 3662-3663.
[1010] See 9 Tr 3663.

He also testified that on average, only 65% of disconnected customers had their service restored within the 16-month study period. Mr. Colton also looked at data on the average arrearage of accounts receiving final notices of disconnection for nonpayment, on the order of $200-600, and believed based on his experience that the arrearages would be higher for customers actually disconnected. He also reviewed data on the aging of arrearages and the overlap with payment plans. He explained one of his conclusions, drawn from the volatility of 30-day arrearages relative to 60-day arrearages:

> More customers, in other words, find it difficult to pay in the seasonally warm summer months. To the extent that that seasonal usage, and thus seasonal bills, could be controlled, DTE would be able to shave the peak of nonpayment costs associated with those high peaking short-term arrears. While there is incomplete data for 2019 (with the data ending in August), the seasonal nonpayment peak certainly appears to be occurring in this most recent year as well. Third, even while the trend line in 30-day arrears shows a distinct downward slope, the trend line in 60-day arrears is virtually flat. The reduction in short-term arrears, in other words, is not being further reflected in DTE's longer-term arrears. Moreover, the longer-term (60-day) arrears are substantial, being in excess of $10 million in every month except the last two. The provision of low-income bill assistance to reduce bills is therefore justified as an effective means to control long term arrears and to control the costs associated with those arrears that are ultimately paid by other ratepayers.[1011]

After noting additional data gaps in DTE's knowledge regarding the success of its payment plans, he also reviewed American Housing Survey data on utility disconnections for Detroit, with data presented in Exhibits MEC-10 and MEC-11. He testified that the information he reviewed from Southeast Michigan is "uniformly consistent with" data generated for natural gas and electric utilities in other states, and discussed experiences in Pennsylvania and Maryland. He testified:

[1011] See 9 Tr 3672.

> The notion that bill payment assistance directed toward low-income customers can yield financial benefits flows from much of the discussion above. The delivery of bill payment assistance to low-income customers not only yields social benefits to the participating customer, but delivers a broad range of other utility cost reductions as well. Accordingly, low-income bill payment assistance should be pursued as an important business tool in controlling system-wide utility costs that are ultimately included in rates to customers. Cost reductions commonly associated with low-income bill payment assistance include savings such as reduced bad debt, reduced working capital, reduced credit and collection expenses, and the like.[1012]

He further testified:

> Cost reductions arise from reductions in arrears in at least the following ways. To the extent that DTE reduces the dollar level of arrears, the Company will experience expense savings. Second, to the extent that DTE reduces the amount of time a customer carries arrears, it will experience expense reductions. Expense reductions include reduced bad debt, reduced working capital and reduced credit and collection expenses. In addition, to the extent that DTE retains its customers against nonpayment disconnections, it preserves future sales and thus future revenue streams.[1013]

After describing measures of success for bill assistance programs, Mr. Colton explained that energy bills represent an ineffective means to send price signals to low-income customers, further explaining that an affordable bill program can improve price signals.[1014] Turning to DTE's programs specifically, Mr. Colton discussed DTE's LSP program, as well as the LIA and RIA credits. He testified:

> The bill payment assistance programs offered by DTE, outside the LSP program which is funded in total through external assistance, is much worse than the Company portrays in the Direct Testimony of Tamara Johnson. According to witness Johnson, the LSP program is "extremely successful" because: "At the end of the 2018 LSP program year: [1] Less than 1% of LSP customers were disconnected for non-payment; [2] 99% of enrollees successfully completed a full year of the program; [and 3] 97% of customers remain within the consumption limits of the program." My examination of

[1012] See 9 Tr 3682-3683.
[1013] See 9 Tr 3685.
[1014] See 9 Tr 3699-3703.

> the quantitative data provided by DTE Electric, discussed below, demonstrates that the affordable bills provided through LSP benefits provided through a non-ratepayer funded program have good payment patterns. In contrast, LIA recipients do not.[1015]

Mr. Colton testified that within the LSP program, LIA credits are counted as a payment, which helps to reduce the payment coverage ratio for LSP participants.[1016] Among his other conclusions, Mr. Colton also testified that graduation rates for the LSP program are quite low, noting that DTE uses graduation as a metric of success of the program.[1017]

Based on his analysis and experience, Mr. Colton recommended: 1) that the LIA credit be expanded to automatically enroll food stamp recipients; 2) that the LIA credit be increased from $40 to $60; 3) an additional benefit for customers living below 50% of the poverty level; 4) redirect RIA credits to low-income customers establishing special needs with incomes at or below 200% of the poverty level. Mr. Colton presented an analysis of the impact these changes would have on affordability.

The MEC Coalition and the Attorney General urge the Commission to adopt Mr. Colton's recommendations. The Attorney General argues:

> One other important conclusion that Mr. Colton demonstrates is that "providing adequate bill assistance to low-income customers will help improve payment outcomes for DTE Electric, thus creating correspondingly positive impacts on reducing the costs associated with nonpayment that are ultimately charged to ratepayers. This is important to note. There is solid, long-term evidence that providing adequate, well-structured bill assistance to low-income customers of a utility is advantageous to both the customers and the utility as a whole.[1018]

[1015] See 9 Tr 3708.
[1016] See 9 Tr 3710.
[1017] See 9 Tr 3715.
[1018] See Attorney General brief, pages 14-15.

Ms. Johnson presented rebuttal testimony, expressing that DTE shares the MEC Coalition and the Attorney General's concerns about bill affordability for low-income customers, but does not recommend an increase to the credit.[1019] She also took issue with Mr. Colton's testimony regarding DTE's data collection:

> [I]t's notable that Colton does not provide this "prudent industry practice" that he references; there is no list of documents or records that he believes comprise an industry standard of record retention. Second, the Company believes that Witness Colton is confusing the time needed to provide data with the ability to provide data to Witness Colton's requests.[1020]

She testified that DTE may have been able to produce additional data if Mr. Colton had submitted his requests in this case, rather than relying on DTE's responses in Case No. U-20373. She also offered an explanation for some of the seasonal variation in disconnections, based on winter shutoff protections, and took issue with his use of current accounts relative to 30 and 60 day payments.[1021] Ms. Johnson also objected to Mr. Colton's critique of the LSP program, testifying that DTE changed its policy for "graduation" from the program from four years to two years in 2018-2019, and under the four-year program, arrears were forgiven over a four-year timeframe.

Ms. Johnson also clarified that the LIA credit is "not part of" the current LSP program, so that some customers in the LSP program do not receive the LIA credit, and the credit is not part of the LSP payment plan.[1022] Nonetheless, she testified:

> "The Company stands by the success of pairing the LIA credit with the LSP program instead of just increasing the LIA credit to $60 as Witness Colton proposes. Disconnect rates for LSP customers receiving LIA is 1.5%

[1019] See 6 Tr 1162.
[1020] See 6 Tr 1157.
[1021] See 1158-1159.
[1022] See 6 Tr 1161.

compared to a 22% disconnect rate for Non LSP customers with no credit assistance."[1023]

She also testified that DTE does not have a cost estimate for configuring its system to automatically upload data from Michigan's Food Stamp office. Regarding Mr. Colton's recommendation for customers living below 50% of the federal poverty level, she testified:

> The Company agrees that not all low-income customers require the same level of assistance. An example of that is the expansion of the tiered payment plans based on FPL% levels in the 2019-2020 LSP program. Although additional assistance would be favorable, Witness Colton does not provide the source for such dollars.[1024]

The MEC Coalition argues:

> DTE's low-income programs provide important benefits but also need improvement. Roger Colton's four recommendations are based on thorough analysis of the data available. DTE acknowledges the need for improved support for customers in poverty, and supports increased participation in existing programs – a necessary but ultimately insufficient step forward. Staff agrees that with some refinement related to measurement, data collection, and evaluation, these recommendations would represent an improvement over the status quo.[1025]

Staff does not support either DTE's proposal or the MEC Coalition and Attorney General's proposal. Mr. Isakson testified that Staff objected to increasing the cap on eligibility for the LIA credit, stating "as this program is still a pilot and the Company is unable to show how successful this program is relative to the RIA, the cap should remain as it is."[1026] Mr. Isakson also took issue with the concept that the Commission "approves funding" for the LSP program:

> [M]ore importantly, the Company should not treat RIA or LIA credits as if they are dependent on a discrete source of funding. In other words, the

[1023] See 6 Tr 1161.
[1024] See 6 Tr 1162.
[1025] See MEC Coalition brief, pages 147-148.
[1026] See 9 Tr 3118, 3119.

Company should never deny a customer a RIA or LIA credit provided the customer meets the requirements set in the Company's Commission-approved tariff, or the LIA cap has been reached. Rather than approve funding for these programs, the Commission instead sets the Company's rates so that projected revenues are sufficient to make up for the projected credits disbursed through the programs. Rates are set such that the Company is projected to receive enough revenue in the test year to offset the projected RIA and LIA credits, but any unexpected change in customer count will necessarily create a mismatch between revenue and the credit total. This is the downside of relying on projected future test years.[1027]

In his rebuttal testimony, Ms. Isakson took issue with Mr. Colton's analysis, testifying that "the absence of appropriate data is not an excuse to rely on a flawed analysis." [1028] He objected that Mr. Colton looked at the affordability of the average bill, asserting that low-income customers "do not necessarily receive the average bill for all customers," and "it is not reasonable to assume that the bill received by the low-income customers matches or even closely resembles the average bill for all customers."[1029] He also objected to Mr. Colton's analysis of small geographic regions on the basis that the Commission does not set rates based on geographic region, and because he believes customer count is the more significant metric.[1030] Mr. Isakson testified:

In summary, the analysis MEC/NRDC/SC/CUB witness Colton provides in support of the argument that electric bills are unaffordable for low income customers should be rejected. However, Staff does not imply that electric bills are affordable for low-income customers. Rather, MEC/NRDC/SC/CUB witness Colton simply provided flawed analyses attempting to illuminate a problem that is already well known to exist.[1031]

[1027] See 9 Tr 3119.
[1028] See 9 Tr 3147.
[1029] See 9 Tr 3147.
[1030] See 9 Tr 3148.
[1031] See 9 Tr 3148.

Mr. Isakson also disputed that a program should be undertaken because they reduce costs to the utility and other customers:

> MEC/NRDC/SC/CUB witness Colton goes to great lengths to describe the manner in which low-income customer programs that increase the likelihood that customers pay their bills and decrease the likelihood that customers are not shut-off for non-payment benefit all other customers. Some of these arguments are either in error or unnecessary. For example, MEC/NRDC/SC/CUB witness Colton posits that when more customers are disconnected for non-payment that other residential customers "… are faced with the financial harms associated with lost customers." In other words, if customers get disconnected for non-payment of bills, then there are fewer customers from which the revenue requirement can be recovered, thus increasing rates. While the mechanics of such a resulting rate increase is true, the opposite is not true: that other residential customers are better off if a low-income program prevents more service disconnections for non-payment. On the whole, residential customers are no better or worse off between the two scenarios: if the class loses customers due to disconnection for non-payment then rates will increase, and if the class does not lose customers in the same way because a low-income program prevents it the other customers' rates will go up to support the program. Either residential customers pay more for lost customers who could not afford their bill without assistance, or their rates go up for providing that assistance. It is still worthwhile to prevent disconnection for non-payment as a moral good, but these nonexistent cost savings are not a reasonable argument in an assistance program's favor. The same contra-argument can be made regarding arrearages.[1032]

Mr. Isakson also testified that shut-off and reconnection costs are now significantly lower due to AMI "so a decrease in disconnection for non-payment resulting from low-income customer programs are negligible."[1033] Nonetheless, Mr. Isakson asserted that "the overall conclusion that it is worthwhile to provide bill assistance for low-income customers remains true."[1034]

[1032] See 9 Tr 3149-3150.
[1033] See 9 Tr 3150.
[1034] See 9 Tr 3151.

Mr. Isakson seemed to agree with Mr. Colton's analysis of DTE's current LSP program, but did not agree that the LIA credit should be increased: "On the contrary, it is a good argument for the elimination of the current pilot in favor of a better designed pilot."[1035] Mr. Isakson also testified that increasing the LIA credit heightens Staff's concerns that DTE would profit from a difference between rate case funding and extended credits.[1036] He recommended that the scope and purpose of the LIA program be redefined. He recommended that the program measure success based on on-time and in-full bill payments. He further testified:

> [a] utility bill is not an effective nor appropriate avenue to address the actual problem of a customer's inability to pay. That actual problem is the customer's income, and not their utility bill. It is neither appropriate nor adequate to address a customer's income, or income inequality more broadly, in the context of a regulatory proceeding regarding electric rates. The three member Michigan Public Service Commission is an unelected board whose mission is to ensure safe, reliable, accessible, and affordable energy. The LIA credit addresses affordability obtusely, because the real cause of the unaffordability of bills is the customer ability to pay. The Commission and its Staff go through massive effort to ensure that rates customers pay reflect the actual service they receive from their utility. The Commission and its Staff cannot, however, affect the income of a utility's customers. Instead, the problem of affordability for low-income customers should be left to the democratically-elected body that grants the Commission its authority.[1037]

In its brief, Staff reiterates Mr. Isakson's arguments, endorsing Mr. Colton's concerns with the LIA pilot while contending that none of his recommendations to expand the program should be adopted.[1038] Staff further argues:

> If the Commission approves the Company's or the relevant parties' proposed changes to the LIA pilot, then additional modifications should also

[1035] See 9 Tr 3151-3152.
[1036] See 9 Tr 3152-3153.
[1037] See 9 Tr 3153-3154.
[1038] See Staff brief, pages 58-60, 94-97.

be made. The Company should first submit an updated evaluation plan for the pilot that will focus on a different, more relevant measure of success. The pilot should be implemented over two years, with a formal evaluation at its conclusion in a dedicated, contested proceeding outside of a general rate case.[1039]

In its reply brief, Staff contends that the MEC Coalition misinterpreted testimony Mr. Isakson provided in cross-examination.[1040]

In its reply brief, the MEC Coalition addresses Staff's arguments in part as follows:

> First, it is not correct that no evidence was presented that more customers would graduate from the LIA (not LSP) program, or that their bills would be affordable. Mr. Colton provided a detailed affordability analysis based on income levels and credit amounts, and MEC-NRDC-SC-CUB described this analysis our initial brief. Nor did the parties "admit" that increasing the credit will not help more customers afford their bills. What Mr. Colton actually said was that while the electric burdens on low-income customers with the larger LIA credit "are still unaffordable, they are not unreasonable outcomes given use of the blunt instrument of equal monthly bill credits across income and usage levels." And as explained in MEC-NRDC-SC-CUB's initial brief, on cross Mr. Isakson agreed that Mr. Colton's recommendation to increase the credit amounts is still a reasonable improvement over the current situation. Mr. Isakson also agreed that "considering [Mr. Colton's] experience, his recommendations and expectations should be given some weight." At least Staff's witness seems to agree that in the face of a daunting problem, doing something imperfect is better than doing nothing.[1041]

While DTE continues to seek expanded funding of LIA credits for its LSP program, in its reply brief, DTE explained:

> The Company agrees that not all low-income customers require the same level of assistance. The Company supports identifying the different levels of assistance and contends that this with the additional changes proposed by Mr. Colton might form the foundation of a pilot. If the Commission approves such modifications, the pilot should be implemented over two years, with a formal evaluation at its conclusion in a dedicated, contested proceeding outside of a general rate case as Staff supports in its Initial Brief

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[1039] See Staff brief, page 97.
[1040] See Staff reply, pages 19-21.
[1041] See MEC Coalition reply, page 52.

> pp 97. In addition, the 4th proposal by Mr. Colton to restructure the RIA program to provide credit to customers between 150% and 200% FPL which is supported by the AG Initial Brief, pp, 20-22; and the MEC/NRDC/SC/CUB Initial Brief, pp 132, 146-47 could also be included in the same pilot. The Company agrees that this low-income population between 151% and 200% FPL is often left on the sidelines when it comes to energy assistance.[1042]

This PFD finds Mr. Colton's testimony persuasive that a well-structured low-income affordability program can not only assist low-income customers but improve the contributions made to utility operations as well. This PFD also finds Mr. Colton's testimony persuasive that credit programs that do not meaningfully address affordability issues are not likely to be successful in accomplishing this latter goal. Given the discussion in the parties' briefs, including DTE's willingness to consider a pilot structured around Mr. Colton's analysis, and Staff's willingness to consider a proposal, this PFD recommends that the current rate case funding for the LIA pilot remain in place with the expectation that DTE will present a revised two-year pilot in its next rate case along the lines indicated in its reply brief as quoted above. In addition, DTE should explore the possibility of obtaining direct information on Food Stamp participants, with a cost and time estimate for the necessary work.

4. Advanced Customer Pricing Pilot

DTE, Staff and the MEC Coalition agree that DTE's time-of-use pilot for residential customers will move forward.

[1042] See DTE reply, page 102.

5. Demand Response Pilots

As discussed above, there is no dispute that DTE's demand response pilots, with the exception of the "other pilots" that Staff considered undefined, will move forward.

F. AMI-Opt-Out Program

Ms. Robinson also discussed the status of the company's opt-out program, including a discussion of the company's obligations as a result of the settlement agreement in Case No. U-20084.[1043] Mr. Crandall proposed modifications to the AMI opt-out program in this case. Responding to Mr. Crandall's testimony regarding the opt-out program, Ms. Robinson relied on the outstanding 600 meters to explain why DTE determined it was not required to review those changes in this case.[1044] She did assert that DTE expected to make its filing in the third quarter of 2020.[1045]

While DTE might well have considered its AMI installations complete when it filed this case, this PFD does recognize merit in DTE's proposal to make its opt out filing in a separate docket in the third quarter of 2020.

G. Interruptible Rate D8 Tariff

Mr. Bloch testified to DTE's proposed changes to the language of DTE's interruptible tariff, Rate D8. Mr. Zakem testified in support of all of the changes with the exception of the "capacity deficiency" language DTE proposed, contending it lacks clarity. In addition to interruption for "system integrity," the new language would add:

[1043] See 9 Tr 2624-2626.
[1044] See 9 Tr 2634.
[1045] See 9 Tr 2635.

> A Capacity Deficiency Interruption Order may be given by the Company when the Company's available generation assets are insufficient to meet the Company's anticipated full service load.[1046]

To Mr. Zakem:

> Since 2005, a Load Serving Entity ("LSE") in MISO does not use only its own generation assets to serve its own load. DTE Electric's load is served by the aggregation of all MISO resources, regardless of how much of its own generation assets are available. For example, if DTE is short capacity, Consumers Energy could be long in capacity, or ample power might able to be imported into the DTE area. The concept of an LSE having to match its owned resources to its own load in daily operations is obsolete, and has been obsolete since 2005.
>
> In addition, the "capacity deficiency" concept does not appear to be designed to preserve reliability at critical times. The non-interruption fee for failure to interrupt following notice of a capacity deficiency is only 0.576 cents per kWh. This presents the customer with a choice: "Do I interrupt my business or manufacturing process, or do I pay another 0.576 cents per kWh for a few hours?" At times when resources might be insufficient to meet electric load – a critical situation – that choice is not a decision that I would recommend be in the hands of the customer. Rather, the decision to interrupt should be in the hands of the system operators, under a well-defined sequence of emergency procedures. The "system integrity" concept works for rate D8, as it does for the other interruptible rates, and should be the only criterion required for D8.[1047]

In rebuttal, Mr. Bloch testified that the capacity deficiency language is only a pricing provision to enable DTE to charge interruptible customers when the MISO LMP is above the energy rate under the D8 tariff and would not authorize DTE to interrupt load:

> Witness Zakem's recommendation conflates the operational requirements to interrupt load under a system integrity order with a pricing provision that does not require interruption. Under a system integrity interruption order (System Integrity) a customer is required to interrupt load. System integrity interruption orders are initiated by either MISO during capacity or transmission emergencies, or DTE Electric during distribution emergencies (which the Company's proposed interruptible tariff and Rule C3 Emergency

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[1046] See Exhibit A-16, Schedule F8, Sheet D 40:00.
[1047] See 9 Tr 2769.

> Electrical Procedures changes fully address). The D8 capacity deficiency provision is a pricing provision that permits a customer to choose to pay higher hourly energy rates under certain market and operating conditions, or avoid paying the higher energy rates by reducing or interrupting their load, at their discretion. This D8 pricing provision, commonly referred to as the "buy-through provision", is economic in nature and not intended for, nor used as, an operational tool as the Company has no rights under this provision to require a customer to interrupt load.[1048]

This PFD agrees with the Foundry Association that the tariff language is insufficiently clear regarding a declaration of a capacity deficiency. For example, Exhibit A-16, Schedule F8, Proposed Sixth Revised Sheet No. D-40.00 states: "Customers may be ordered to interrupt only when the Company finds it necessary to do so either to maintain system integrity or when the existence of such loads shall lead to a capacity deficiency by the utility." This language is more than a mere pricing provision. Additionally, to achieve DTE's stated goal, what causes DTE to declare a capacity deficiency should at a minimum be tethered to a reasonable belief that it will be obligated to pay more than the energy rate under the tariff. DTE should work with stakeholders to improve the clarity of this language for reconsideration in its next rate case.

H. Rate Effective Date

Mr. Isakson testified that to allow time for DTE's billing system to incorporate the new rates that will be set in this case, the effective date should be seven calendar days from the date the order is issues. He also testified that as an alternative, the Commission could provide an opportunity for the parties to review and comment on the final rates in

[1048] See 8 Tr 2296.

an effort to reduce errors. He suggested a period of 21 days for the review, with a tariff order issued within 30 days of the final rate order.[1049]

DTE has no objection to the 7-day window, but does object to a longer period to correct potential errors, arguing that it does not oppose having a means to correct errors, but believes any errors can be corrected as soon as they are found.[1050] DTE contends that Staff's proposal could turn a 10-month case into an 11-month case, and cause the company financial harm.

This PDF finds that the question of the effective dates of rates set in the Commission's final order in this case is a matter for the Commission's discretion. Unlike some cases, this PFD is not aware of any particularly difficult issues of tariff language, rate design, or cost allocation that would require additional time beyond the 7 days Staff identifies as a standard period.

XII.

CONCLUSION

Based on the foregoing discussion, this PDF 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 $99.94 million, with an authorized return on equity of 9.8% and an overall cost of capital of 5.42%, as well as recommendations regarding various accounting

[1049] See 9 Tr 3127-3128.
[1050] See DTE reply, page 108.

requests, cost of service allocations, and rate design, as well as recommendations for additional Commission investigation, and additional utility reporting and analysis.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Sharon L. Feldman

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Date: 2020.03.05 15:32:44 -05'00'

Sharon L. Feldman
Administrative Law Judge

March 5, 2020
Lansing, Michigan

Michigan Public Service Commission | **Appendix A**
DTE Electric Company | PFD
Projected Revenue Deficiency (Sufficiency) | Case No. U-20561
Projected 12 Month Period Ending April 30, 2021
($000)

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**Applicant Projection (Reply Brief)**	**PFD Adjustment**	**PFD Projection**
1	Rate Base	Exh. S-2, Sch. B1	18,167,548	(1,071,178)	17,096,370
2	Adjusted Net Operating Income	Exh. A-13, Sch. C1	788,979	66,040	855,019
3	Overall Rate of Return	Line 2 ÷ Line 1	4.34%	0.66%	5.00%
4	Required Rate of Return	Exh. A-14, Sch. D1	5.73%	-0.31%	5.42%
5	Income Requirements	Line 1 x Line 4	1,041,691	(114,257)	927,433
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	252,712	(180,298)	72,415
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	1.3496	-	1.3496
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	341,070	(243,337)	97,733
9	Revenue Deficiency - Tree Trim Surge Program	Exh. A-11, Sch. A1.1	2,104	-	2,104
10	Revenue Deficiency / (Sufficiency)-Total	Line 8 + Line 9	343,174	(243,337)	99,837

Michigan Public Service Commission | **Appendix B**
DTE Electric Company | PFD
Projected Rate Base | Case No. U-20561
Projected Average Balances Period Ending April 30, 2021
($000)

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**Applicant Projection (Reply Brief)**	**PFD Adjustment**	**PFD Projection**
1	Utility Plant in Service:				
2	Plant in Service	Exh. A-12, Sch. B2, L6	22,321,701	(276,516)	22,045,186
3	Plant Held for Future Use	Exh. A-12, Sch. B2, L7	75,808	-	75,808
4	Construction Work in Progress	Exh. A-12, Sch. B2, L8	1,851,001	-	1,851,001
5	Acquisition Adjustments	Exh. A-12, Sch. B2, L9	110,357	-	110,357
6	Total Utility Plant	Sum Lines 2 thru 5	24,358,867	(276,516)	24,082,351
7	Depreciation Reserve	Exh. A-12, Sch. B3, L6	(7,732,707)	15,166	(7,717,541)
8	Net Utility Plant	Line 6 + Line 7	16,626,160	(261,350)	16,364,810
9	Net Capital Lease Property	Exh. A-12, Sch. B4.1, col. (c), L10	3,785	-	3,785
10	Net Nuclear Fuel Property	Exh. A-12, Sch. B4.1, col. (c), L11	149,310	-	149,310
11	Total Utility Property and Plant	Sum Lines 8 thru 10	16,779,255	(261,350)	16,517,905
12	Less: Capital Lease Obligations	Exh. A-12, Sch. B4.1, col. (c), L70 + L82	3,798	-	3,798
13	Net Plant	Line 11 - Line 12	16,775,456	(261,350)	16,514,107
14	Allowance for Working Capital	Exh.A-12, Sch. B4	1,392,092	(809,830)	582,263
15	Total Rate Base	Line 13 + Line 14	18,167,548	(1,071,178)	17,096,370

MICHIGAN PUBLIC SERVICE COMMISSION

Appendix C
PFD
Case No. U-20561

DTE Electric Energy Company
Projected Net Operating Income
for the Test Year Ended April 30, 2021
($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 Rider	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																	
	Operating Income (Initial Filing)	3,390,739	1,384,989	91,637	4,867,365	1,384,989	1,353,445	949,590	279,646	52,120	43,559	43,484	1,881	4,108,714	758,650	31,892	(2,327)	788,214
	EV Amortization - Electric Marketing						(1,000)				62	197						
	Corporate Membership Dues						(285)				18	56						
	Depreciation on Contingency							(412)			26	81						
	Interest Sync	-	-	-	-	-	-	-	-	-	-	369	-	-	-	-	-	-
	Operating Income (Initial Brief)	**3,390,739**	**1,384,989**	**91,637**	**4,867,365**	**1,384,989**	**1,352,160**	**949,178**	**279,646**	**52,120**	**43,665**	**44,187**	**1,881**	**4,107,826**	**759,539**	**31,892**	**(2,327)**	**789,104**
	Energy Bridges			527	527						33	104		137	390			390
	Uncollectibles						770				(48)	(152)		571	(571)			(571)
	Taxes	-	-	-	-	-	-	-	-	-	309	(364)	-	(55)	55	-	-	55
1	**Operating Income (Reply Brief)**	**3,390,739**	**1,384,989**	**92,164**	**4,867,892**	**1,384,989**	**1,352,930**	**949,178**	**279,646**	**52,120**	**43,959**	**43,775**	**1,881**	**4,108,478**	**759,414**	**31,892**	**(2,327)**	**788,979**
	PFD Adjustments																	
2	Power Supply Rev/Exp (Shi)		-		-	-					-	-		-	-			-
3	Sales Revenue (Isakson)	10,170			10,170						632	2,003		2,635	7,535			7,535
4	Misc Revenue (Isakson)			-	-						-	-		-	-			-
5					-						-	-		-	-			-
6	AG Inflation Adjustment (AG 1.9%, 2.1%, 1.8%; Staff Reply Brief, Appendix G, line 35)						(20,172)				1,253	3,973		(14,946)	14,946			14,946
7					-						-	-		-	-			-
8	**Customer Service:**										-	-		-	-			-
9	IT - Bill Redesign O&M (Wang)				-		(576)				36	113		(427)	427			427
10	IT - AMI Enhanced Support O&M (Wang)				-		(600)				37	118		(445)	445			445
11	Merchant Fees (McMillan-Sepkoski)				-		(10,747)				667	2,117		(7,963)	7,963			7,963
12					-						-	-		-	-			-
13	**Uncollectibles (AG)**				-		(2,870)				178	565		(2,127)	2,127			2,127
14					-						-	-		-	-			
15	**Corporate Support**				-						-	-		-	-			-
16	Injuries and Damages (McMillan-Sepkoski)				-		(1,605)				100	316		(1,189)	1,189			1,189
17	Incentive Compensation (McMillan-Sepkoski)				-		(28,438)				1,766	5,601		(21,071)	21,071			21,071
18	Restricted Stock (McMillan-Sepkoski)				-		(3,670)				228	723		(2,719)	2,719			2,719
19					-						-	-		-	-			-
20	River Rouge Unit 3				-		(1,660)				103	327		(1,230)	1,230			1,230
21	Wellness (AG)				-		(1,817)				113	358		(1,346)	1,346			1,346
22					-						-	-		-	-			-
23	Impact of Cap Ex Adj on Depreciation (Edelyn)				-			(15,549)			966	3,063		(11,521)	11,521			11,521
24	Reclass State Tax & FIT in DTE Interest Sync				-						89	(89)		-	-			-
25																		(1)
26	Proforma Interest (Nichols)				-						1,548	4,910		6,458	(6,458)			(6,458)
27	Interest Synchronization (Nichols)	-	-	-	-	-	-	-	-	-	5	15	-	19	(19)	-	-	(19)
28	**Total Adjustments**	**10,170**	**-**	**-**	**10,170**	**-**	**(72,155)**	**(15,549)**	**-**	**-**	**7,720**	**24,113**	**-**	**(55,872)**	**66,042**	**-**	**-**	**66,040**
29	**PFD NOI - Test Year**	**3,400,909**	**1,384,989**	**92,164**	**4,878,062**	**1,384,989**	**1,280,775**	**933,629**	**279,646**	**52,120**	**51,678**	**67,888**	**1,881**	**4,052,606**	**825,455**	**31,892**	**(2,327)**	**855,019**

Michigan Public Service Commission
DTE Electric Company
Projected Rate of Return Summary
For Period Ending April 30, 2021

Appendix D
PFD
Case No. U-20561

	(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	6,995,149	50.00%	38.33%	4.22%	2.11%	1.62%	1.0000	1.62%
2	Preferred Stock	0	0.00%	0.00%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Shareholders' Equity	6,993,099	50.00%	38.32%	9.80%	4.90%	3.75%	1.3496	5.07%
4	Total	13,988,248	100.00%			7.01%			
5	Short-Term Debt	219,881		1.20%	2.73%		0.03%	1.0000	0.03%
6	Investment Tax Credit (ITC) - Debt	24,309		0.13%	4.22%		0.01%	1.0000	0.01%
7	Investment Tax Credit (ITC) - Equity	24,309		0.13%	9.80%		0.01%	1.3496	0.02%
8	Total Investment Tax Credit (ITC)	48,618							
9	Deferred Income Taxes (Net)	3,994,582		21.89%	0.000%		0.00%		0.00%
10	Total	18,251,329		100.00%			5.42%		6.74%

Michigan Public Service Commission
DTE Electric Company
Capital Expenditure and Rate Base Adjustments
Projected 12 Month Period Ending April 30, 2021
($000)

Appendix E
PFD
Case No. U-20561

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			Total	**Test Year Impacts From Adjustment(s) to Capital Spend Projects**				
Line	**Party**	**Adjustment Description**	**Cap Ex Adj.**	**Plant**	**Accum Dep.**	**Rate Base**	**Depreciation**	**O&M**
1								
2	Staff / AG	CONTINGENCY	DTE Adopted at Brief					
3								
4	**Production Capital**							
5	MEC - PFD	River Rouge Unit 3	(10,314)	(10,314)	(657)	(9,657)	(309)	-
6			-	-	-	-	-	-
7	AG - PFD	Routine Projects - Monroe - Unit 3 SCR Catalyst Layers 2, 3, & 4	(347)	(347)	(14)	(333)	(10)	-
8	AG - PFD	Routine Projects - Monroe - Unit 3 Expansion Joints	(1,060)	(1,060)	(42)	(1,018)	(32)	-
9	AG - PFD	Routine Projects - Peakers - Belle River Turbine Combustion & Hot Gas Path	(579)	(579)	(23)	(556)	(17)	-
10	AG - PFD	Routine Projects - Peakers - Delray Gas Compressors	(4,000)	(4,000)	(160)	(3,840)	(120)	-
11	AG - PFD	Routine Projects - Belle River - Unit 2 LP Turbine Blades	(1,247)	(832)	(15)	(817)	(25)	-
12	AG - PFD	Routine Projects - Belle River - Unit 2 IP Turbine Blades	(3,522)	(2,348)	(41)	(2,307)	(70)	-
13	AG - PFD	Routine Projects - Greenwood - Unit 1 Main Unit Transformer	(401)	(267)	(5)	(262)	(8)	-
14	AG - PFD	Routine Projects - Monroe - Unit 4 Secondary Superheat Inlet	(586)	(390)	(7)	(384)	(12)	-
15	AG - PFD	Routine Projects - Monroe - Unit 4 Main Generator Stator	(289)	(192)	(3)	(189)	(6)	-
16	AG - PFD	Routine Projects - Monroe - Turbine & Boiler House Vent Fans	(3,000)	(2,000)	(35)	(1,965)	(60)	-
17	AG - PFD	Routine Projects - Hancock - 11-4 Peaker Turbine Hot Gas Path	(4,000)	(2,667)	(47)	(2,620)	(80)	-
18	AG - PFD	Routine Projects - Renaissance - Unit 1 Peaker Turbine Combustion & Hot Gas Path	(4,000)	(2,667)	(47)	(2,620)	(80)	-
19	AG - PFD	Routine Projects - Greenwood - Main Unit Transformer	(2,267)	(1,133)	(17)	(1,116)	(34)	-
20	AG - PFD	Routine Projects - Greenwood - Condenser Air Removal Tubes	(2,000)	(1,000)	(15)	(985)	(30)	-
21	AG - PFD	Routine Projects - Greenwood - South Boiler Feed Pump Turbine Blades	(1,600)	(800)	(12)	(788)	(24)	-
22	AG - PFD	Routine Projects - Greenwood - North Boiler Feed Pump Turbine Blades	(1,600)	(800)	(12)	(788)	(24)	-
23	AG - PFD	Routine Projects - Greenwood - Turbine Valves	(1,333)	(667)	(10)	(657)	(20)	-
24	AG - PFD	Routine Projects - Monroe - Unit 3 SCR Catalyst	(1,667)	(833)	(13)	(821)	(25)	-
25	AG - PFD	Routine Projects - Monroe - Units 1-4 DCS-HMI	(2,333)	(1,167)	(17)	(1,149)	(35)	-
26			-	-	-	-	-	-
27	AG - PFD	Non-Routine Projects - Monroe Bottom Ash Basin CCR	(39,985)	(29,528)	(755)	(28,773)	(886)	-
28	ABATE - PFD	Non-Routine Projects - Monroe Fly Ash Dry Conversion (ELG)	(73,738)	(46,086)	(929)	(45,157)	(1,383)	-
29			-	-	-	-	-	-
30	**Distribution Capital**		-	-	-	-	-	-
31	AG - PFD	Base Capital Programs - Emergent Replacements	(8,693)	(6,124)	(223)	(5,902)	(251)	-
32	AG - PFD	Base Capital Programs - Customer Connections, Relocations, Other	(5,914)	(4,175)	(152)	(4,023)	(171)	-
33			-	-	-	-	-	-
34	AG - PFD	Strategic Capital Programs - Reduce 2019 by 20%	(70,377)	(70,377)	(3,847)	(66,530)	(2,885)	-
35			-	-	-	-	-	-
36	Staff - PFD	AMI: 3G to 4G Upgrade (Add. Cell Relays)	(2,000)	(2,000)	(76)	(1,924)	(101)	-
37	Staff - PFD	AMI: 3G to 4G Industrial Communication Upgrade (Power Quality Meters)	(3,820)	(3,820)	(282)	(3,538)	(193)	-
38			-	-	-	-	-	-
39	Staff - PFD	Demand Response - Other Pilots beyone BYOD and EPRI	(2,000)	(1,000)	(21)	(980)	(41)	-
40			-	-	-	-	-	-
41	**IT Capital**		-	-	-	-	-	-
42	AG - PFD	IT - Corp Applications - Purchase To Pay (P2P)	(4,880)	(3,366)	(455)	(2,911)	(575)	-
43	AG - PFD	IT - Customer Service - Web Portal Re-build and Transformation	(17,195)	(10,488)	(1,003)	(9,485)	(1,791)	-
44	AG - PFD	IT - Corp Applications - Success Factors Program	(8,784)	(6,267)	(908)	(5,358)	(1,070)	-
45			-	-	-	-	-	-
46	Staff - PFD	IT - Digital Engagement Group Establishment	(9,200)	(5,752)	(557)	(5,195)	(982)	-
47	Staff - PFD	IT - Bill Redesign	(5,524)	(3,388)	(325)	(3,063)	(579)	(576)
48	Staff - PFD	IT - Fixed Bill Pilot	(2,750)	(1,720)	(166)	(1,553)	(294)	-
49	Staff - PFD	IT - 2019 Emergent	(3,132)	(3,132)	(713)	(2,419)	(535)	(600)
50	Staff - PFD	IT - Applied Innovation	(4,482)	(2,482)	(226)	(2,256)	(424)	-
51	Staff - PFD	IT -Network-Advanced Metering Infrastructure Enhanced Support	(5,538)	(4,438)	(973)	(3,465)	(758)	-
52			-	-	-	-	-	-
53	**Other**		-	-	-	-	-	-
54	Welke - PFD	Charging Forward Cap Ex	(618)	(618)	(34)	(584)	(25)	-
55			-	-	-	-	-	-
56	AG - PFD	Short Term - Capitalized Incentive Compensation	(25,156)	(21,322)	(1,307)	(20,014)	(896)	-
57	AG - PFD	Long Term - Capitalized Incentive Compensation	(19,223)	(16,372)	(1,023)	(15,349)	(688)	-
58								
59		**TOTAL**	**(359,154)**	**(276,516)**	**(15,166)**	**(261,350)**	**(15,549)**	**(1,176)**
60								
61		**WORKING CAPITAL ADJUSTMENTS**						
62		Accounts Payable - Assoc Company				DTE Adopted at Brief		
63		Account Rec - Assoc Company - REF				DTE Adopted at Brief		
64		Account Rec - Assoc Company				(11,271)		
65		Charging Forward Regulatory Asset				(4,210)		
66		Prepaid Pension Asset				(794,348)		
67		**TOTAL WORKING CAPITAL ADJUSTMENTS**				**(809,830)**		
68		**TOTAL RATE BASE ADJUSTMENTS**				**(1,071,180)**		

STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

STATE OF MICHIGAN	)	
	)	
County of Ingham	)	Case No. U-20561
	)	

PROOF OF SERVICE

Meaghan Dobie being duly sworn, deposes and says that on March 5, 2020, she served a copy of the attached Notice of Proposal for Decision and Proposal for Decision via email and/or first-class mail, to the persons as shown on the attached service list.

Meaghan Dobie

Meaghan Dobie

Subscribed and sworn to before me
this 5th day of March 2020.

Brianna L. Brown

Brianna L. Brown
Notary Public, Clinton County
My Commission Expires July 4, 2021

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CASE NO. U-20561

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