STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, for miscellaneous accounting authority _____________________________________/	Case No. **U-20162** (**e-file paperless**)

MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S
INITIAL BRIEF

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

Amit T. Singh (P75492)
Spencer A. Sattler (P70524)
Daniel E. Sonneveldt (P58222)
Assistant Attorneys General
Public Service Division
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917
Telephone: (517) 284-8140

DATED: January 11, 2019

Table of Contents

Page No.

I. Introduction

In its initial filing, the DTE Electric Company ("DTE" or "Company") projects that it will experience a total electric revenue deficiency of $328.440 million for the test year ending April 30, 2020 (Exhibit A-11, Schedule A1), while Staff projects that DTE's total electric revenue deficiency will be $133.36 million. (Appendix A.) Additionally, with new rates effective in the instant case, the Tax Cuts and Jobs Act (TCJA) Credit A, as determined in Case No. U-20105, will cease, effectively increasing rates by an additional $148.237 million. (Appendix A.) When Staff's $133.36 million deficiency is added to the $148.237 million increase due to ceasing the TCJA Credit A, the net rate increase is actually $281.597 million. (Appendix A.) Staff's lower rate base, return on equity, and operating expenses are primarily responsible for the difference:

i. DTE's projected total rate base is $17.173 billion, while Staff's total projected rate base is $17.051 billion—$121.234 million less than the Company's. (Appendix B.) It is lower because Staff reduced the Company's plant in service by $108.368 million (including adjustments to contingency, steam generation, charging forward, demand side management, information technology, and distribution capital expenditures), reduced the depreciation reserve (an offset to total utility plant) by $37.720 million, and reduced working capital by $50.586 million. (Appendix E.)

ii. DTE's proposed ROE is 10.5%. Staff's recommended ROE is 9.8%. (Appendix D.) The intervening parties recommend ROE's below 9.8%.

Staff's lower ROE reduces the Company's projected revenue deficiency by about $63 million. Staff's ROE differs from the Company's by 70 basis points because Staff used several different ROE inputs.

iii. DTE projects that its total company operating expenses will be $4.065 billion, while Staff projects that they will be $3.988 billion—$76.189 million less than the Company projects. (Appendix C.) Staff's proposed operating expenses are lower because Staff adjusted the Company's Operation and Maintenance (O&M) expense to reduce, among other things, the Company's inflation factors, injuries and damages expense, incentive compensation expense, uncollectibles expense, active healthcare expense, incremental charge forward expense, meter reading expense, and tree trimming expense. Additionally, Staff reduced depreciation expense by $65.238 million to reflect the new approved depreciation rates in MPSC Case No. U-18150 in lieu of the depreciation rates reflected in the Company's case, which are those that were initially proposed by the Company in MPSC Case No. U-18150 prior to the Commission issuing a final Order.

Staff's disallowances are justified and well supported. Staff strove to strike the right balance between DTE's interests and its ratepayers' interests. Public utilities are entitled to a reasonable opportunity to earn a reasonable rate of return on their investments, *ABATE v Public Service Comm*, 430 Mich 33, 39 (1988), just like ratepayers are entitled to just and reasonable rates. The just-and-reasonable-rate doctrine is "aimed at navigating the straits between gouging utility customers and confiscating utility property." *Verizon Communications, Inc v FCC*, 535 US 467, 481 (2002). Staff's adjustments are well within these bounds.

Staff is recommending "just and reasonable rates that are fair to both ratepayers and the company." *In re Detroit Edison Co*, MPSC Case No. U-15244, 12/23/08 Opinion & Order, p 11. Although many of DTE's proposed rate increases are justified, many are not. In several instances, the Company has overreached by inflating its capital-expenditure and operating-expense projections beyond reasonable expectations. In other instances, the Company has ignored Commission precedent and asked to recover expenses that it has requested before and been repeatedly denied. Staff made adjustments to correct these excesses.

In conclusion, DTE does not need a $328.440 million rate increase, but in light of the considerable capital investments in its future an increase appears warranted. Staff's proposed $133.36 million rate increase and 9.80% ROE gives the Company a reasonable opportunity to earn a fair rate of return and gives ratepayers access to safe and reliable energy at reasonable rates.

II. Revenue Deficiency

The $195.08 million difference between the Company's proposed total revenue deficiency ($328.440 million) and Staff's proposed total revenue deficiency ($133.36 million) is due to the following adjustments (in millions):

Rate base (revenue requirement impact)	$ (8.7)[1]
Change in rate of return	$ (71.2)[2]
O&M adjustment	$ (32.6)[3]
Sales Revenue adjustment – RIA	$ (0.9)[3]
Depreciation adjustment	$ (71.5)[3]
Tree Trim Surge	$ (7.1)[4]
AFUDC Adjustment	$ (2.6)[5]
Tax Reform Reg. Liability Amort. Adj.	$ (0.6)[6]
Total Staff adjustments (rev. req. impact)	**$(195.08)[7]**

III. Rate Base

"Rate base consists of the capital invested in utility plant, less accumulated depreciation [i.e., net plant], plus the utility's working capital requirement." *In re Detroit Edison's 2010–2011 Rate Case*, MPSC Case No. U-16472, 10/20/2011 Order, p 5. In this case, rate base also includes retainers and customer advances.

A. Staff recommends a total rate base of $17,051,324,000.

DTE projected that its total electric rate base will be $17.173 billion in the projected test year ending April 30, 2020. (Exhibit A-11, Schedule A1.) Staff

[1] Change in rate base of ($121,234,000) x pre-tax rate of return 7.19% = ($8.7 million) revenue requirement impact. Appendix B, D, E

[2] Change in pre-tax rate of return of (0.42%) x $17,051,324,000 rate base = ($71.2 million) revenue requirement impact. Appendix D, B, Exhibit A-14, Sch. D1

[3] Appendix C, line 18

[4] Appendix A, line 9

[5] Appendix C, line 12 x 1.3496 revenue conversion factor on Appendix A, line 7

[6] Appendix C, line 15 x 1.3496 revenue conversion factor on Appendix A, line 7

[7] Appendix A, line 10

accepted the method that DTE used to develop its rate base projection, but Staff has projected that total rate base will be $17.051 billion, which is $121.234 million less than the Company's. (Appendix B and Appendix E.) The difference is due to a $70.648 million reduction to net utility plant and a $50.586 million reduction to working capital.

1. Staff recommends a net utility plant of $15,460,854,000.

The first component of rate base is net utility plant. Net utility plant consists of total utility plant minus accumulated depreciation and amortization. The Company's proposed total net utility plant is $15.532 billion, while Staff's recommended total net utility plant is $15.461 billion. (Appendix B.)

Staff's proposed net plant is $70.648 million lower than the Company's because of a $108.368 million reduction to total utility plant, offset by a $37.720 million reduction to accumulated depreciation and amortization. (Appendix B and Appendix E.)

a. Staff recommends a total utility plant of $23,062,711,000.

The first component of net utility plant is total utility plant. DTE's total utility plant is $23.171 billion; Staff's total utility plant is $23.063 billion. (Appendix B.) Staff's total utility plant is $108.368 million less than the Company's because Staff reduced the Company's contingency, steam generation, charging forward, demand side management, information technology, and distribution capital expenditures. (See Section III.B. and Appendix E for these capital expenditure adjustments.)

b. Staff recommends an accumulated depreciation and amortization reserve of $7,601,857,000.

The second component of net utility plant is the accumulated depreciation and amortization reserve. DTE projected that its total accumulated depreciation and amortization reserve will be $7.640 billion in the projected test year. Staff recommended a $7.602 billion reserve. (Appendix B.) Staff's recommendation is $37.720 million less than the Company's, after adjusting the Company's capital expenditure projections. (Section III.B and Appendix E.)

2. Staff recommends net capital lease property of $6,222,000.

The second component of rate base is net capital lease property. Staff recommends the ALJ and the Commission adopt the Company's net capital lease property of $6,222,000. (Appendix B.)

3. Staff recommends net nuclear fuel property of $112,164,000.

The third component of rate base is net nuclear fuel property. Staff recommends the ALJ and the Commission adopt the Company's net nuclear fuel property of $112,164,000. (Appendix B.)

4. Staff recommends capital lease obligations of $6,324,000.

The fourth component of rate base is capital lease obligations. Staff recommends the ALJ and Commission adopt the Company's projection of $6,324,000. (Appendix B.)

5. Staff recommends a total working capital of $1,478,408,000.

The fifth component of rate base is working capital. The Company forecasted that its total working capital requirement for the projected test year will be $1.478 billion, which is $50.586 million less than the company's projection of $1.529 billion. (Exhibit S-2, Schedule B4; Appendix B; Appendix E.) Staff's working capital is less than the company's because Staff adjusted regulatory liability—active health care credit, prepaid pension asset, charging forward, charging forward double count, and interest payable, which are discussed below.

a. Staff recommends reducing working capital by $4,334,000 for an adjustment to regulatory liability – active health care credit.

Staff made a $1,733,000 adjustment to the Company's active healthcare Operations and Maintenance (O&M) expense for the test year. Staff's adjustment results in a $4,334,000 adjustment to the Company's working capital. The details of Staff's adjustment are discussed in section V.A.2.(a)(v.), page 77, below.

b. Staff recommends reducing working capital by $44,623,000 for an adjustment to prepaid pension asset.

The Company requested approval for deferred debit—prepaid pension asset of $841,087,000 for the projected test year. A response from the Company to ABATE confirms that the prepaid pension asset was filed incorrectly due to a formula error and should have been $796,464,000. (Exhibit S-7.1). The Company did not address Staff's adjustment in rebuttal, therefore Staff presumes DTE agrees. Staff maintains its position and recommends that the ALJ and the

Commission find that the deferred debit—prepaid pension asset costs are $796,464,000 for the projected test year.

c. Staff recommends reducing working capital by $793,000 for an adjustment to charging forward.

Staff provided several recommendations and adjustments to the Company's Charging Forward program. Details of Staff's recommendations are provided in Section VII below in this brief. Staff's recommendations result in a $793,000 reduction to working capital.

d. Staff recommends reducing working capital by $793,000 for an adjustment to charging forward—double count.

The Company requested approval for other deferred debits of $21,711,000 for the projected test year. A response from the Company confirms that they double counted the reg asset—charging forward balance of $793,000 and included it in other deferred debits. (Exhibit S-7.2). Because of this error, other deferred debits should have been $20,919,000. (Exhibit S-2, Schedule B4). No party addressed Staff's adjustment in rebuttal testimony. Staff recommends that the ALJ and the Commission find that the other deferred debit costs are $20,919,000 for the projected test year.

e. Staff recommends reducing working capital by $45,000 for an adjustment to interest payable.

The Company requested approval for interest payable of $73,951,000 for the projected test year. A response from the Company confirms that interest payable was filed incorrectly due to a formula error and should have been $73,996,000.

(Exhibit S-7.4). Staff recommends that the ALJ and the Commission find that the interest payable costs are $73,996,000 for the projected test year.

B. Staff recommends several reductions to the Company's capital expenditures.

As discussed above, Staff's total utility plant is $108.368 million lower than the Company's because Staff adjusted the Company's contingency, steam generation, charging forward, demand side management, information technology, and distribution capital expenditures. (Appendix E.) The following table shows the adjustments, which are explained below:

	Total	Test Year Impacts From Staff Adjustments to Cap Ex Projects			
Adjustment Description	Cap Ex Adj.	Plant Adj.	Accum Depr.	Rate Base	Depreciation
CONTINGENCY: STEAM GENERATION - Combined Cycle - 2022	(10,533)	(8,217)	(120)	(8,097)	(158)
CONTINGENCY: CORPORATE STAFF - HQ Energy Center	(4,470)	(3,218)	(181)	(3,037)	(240)
TOTAL CONTINGENCY	(15,003)	(11,434)	(300)	(11,134)	(397)
STEAM GENERATION - Monroe Dry Fly Ash Processing	(34,100)	(21,767)	(396)	(21,371)	(653)
CHARGING FORWARD - Total Capital	(1,744)	(872)	(18)	(854)	(36)
DEMAND SIDE MGMT - Programmable Communicating Thermostats	(9,593)	(7,880)	(1,607)	(6,273)	(1,576)
IT - Corporate Application Projects	(625)	(313)	(31)	(281)	(63)
IT - Customer Service Projects	(3,674)	(2,144)	(235)	(1,909)	(429)
IT - Plant and Field Projects	(3,150)	(1,846)	(227)	(1,619)	(369)
IT- Information Technology for IT Projects	(6,170)	(4,452)	(290)	(4,162)	(334)
TOTAL IT	(13,619)	(8,754)	(783)	(7,971)	(1,195)
DISTRIBUTION PLANT - INFRASTRUCTURE REDESIGN - Total Capital	(74,188)	(57,662)	(1,998)	(55,663)	(2,376)
Total Cap Ex Adjustments Impact	(148,247)	(108,368)	(5,101)	(103,267)	(6,233)

1. The Commission should exclude $15,003,000 in projected contingencies from DTE's projected capital expenditures.

Staff recommends the removal of $15,003,000 of contingency capital expenditures, which reduces rate base by $11,134,000. (Appendix E.) Staff witnesses Jonathan DeCooman and Cody Matthews testified that it is imprudent to include projected contingency costs in rates due to the uncertainty of these expenditures being incurred, shifting the risk associated with these expenses onto ratepayers. (8 TR 4197; 8 TR 4154-4155.) Staff points out that the Commission has previously denied the Company's request to recover projected contingency expenditures in *In re DTE Electric Co. Rate Case*, MPSC Case No. U-18014, 1/31/2017 Order, pp 13, 42; *In re DTE Electric Co. Rate Case*, MPSC Case No. U-17767, 12/11/2015 Order, pp 19, 23; *In re Detroit Edison Co. Rate Case*, MPSC Case No. U-16489, 10/20/2011 Order, p 22. Further, the Commission has disallowed contingency costs in numerous other utilities' rate cases based on the speculative nature of projected contingency costs. (8 TR 4197; 8 TR 4154-4155.) Given the Company's inability to update the record with additional information on the specific area and need for these contingency funds, Staff is unable to review these expenditures for reasonableness and prudence. (8 TR 4199.)

The Attorney General (AG) supported Staff's recommendation for disallowance of projected contingency for the Combined Cycle plant. AG Witness Sebastian Coppola cited an order in the Company's Certificate of Necessity application, MPSC Case No. U-18419, 04/27/2018 Order, p 126, as the basis for this disallowance. (5 TR 1625.) Witness Coppola noted that while the $951.8 million in approved costs included $17.8 million in contingency costs, emphasis should be placed on the order's directive that *actual* incurred costs be included in the Company's rates. *Id*. Company Witness Matthew Paul refuted this recommended disallowance, citing the $951.8 million in approved costs, stating that "[b]ecause only approximately two-thirds of the total project costs ($650 million) are being requested for recovery in this case, it would be premature to disallow a portion of the approved funding at this time." (4 TR 598.)

Staff finds the Company's rebuttal testimony on this subject inadequate to support the Company's position. Disallowance of the projected contingency costs in this case does not preclude the Company from recovering these costs in a future filing, once they have been incurred. Therefore, the disallowance of these costs is not premature, as the Company has asserted. (4 TR 598.) Staff contends the request for costs to be included in rates that cannot be connected to a specific expense should be considered premature. For these reasons, Staff recommends the removal of $15,003,000 of contingency capital expenditures from the Company's rate request.

2. The Commission should exclude $34,100,00 from DTE's projected steam generation capital expenditures.

Staff recommends disallowance of the costs for the 'Monroe dry fly ash processing' project, reducing the Company's steam power generation capital expenditures by $34,100,000, which reduces rate base by $21,371,000. (Appendix E.) Staff witness Jonathan DeCooman testified that the Company did not fully support the benefits this project would generate for ratepayers or demonstrate a need for this project to comply with any local, state or federal regulations. (8 TR 4186.) Staff cited the Company's lack of internal budgetary approval, the lack of an executed contract for construction, and questions about the net present value (NPV) analysis as reasons for disallowance. (8 TR 4191-4192.) Staff emphasized that this project may present a net benefit to both Company and ratepayer, and recommended the Commission direct the Company to further develop the project and hold technical discussions with Staff to further facilitate an understanding of the NPV analysis and its inputs as it develops. *Id.*

The AG supported Staff's recommendation for disallowance of costs associated with the 'Monroe dry fly ash processing' project. Witness Coppola recommends disallowance for similar reasons as Staff, the lack of internal budgetary approval and the lack of a contract for construction of the project. (5 TR 1636-1637.) Witness Coppola also recommends capital costs for additional non-routine steam power generation projects be removed from the Company's rate base; shown in lines 5 and 18 on page 2 of Exhibit A-12, schedule B 5.1. (5 TR 1636.) Witness Coppola's recommendation is based on the Environmental Protection Agency's (EPA) recent consideration of revisions to the rules that require the Company complete these projects for compliance. *Id.* Company witness Matthew Paul disputed the AG's recommended disallowances, stating that no weight should be given to witness Coppola's recommendations due to his reliance on a possible reconsideration of the Effluent Limitations Guidelines (ELG) rules that mandate these projects be completed by December 31, 2023. (4 TR 598-600.) Witness Paul states that the portions of the ELG that are being reconsidered have no impact on the requirement for the additional projects that witness Coppola recommended disallowance of. *Id*. Witness Paul also countered Staff and the AG's recommendation of disallowance of costs associated with the 'Monroe dry fly ash processing' project, stating that while the Company has not received complete internal project approval for this project, "[T]he Company believes this project is reasonable and prudent since this project drives economic value for our customers by lowering PSCR costs and supports the Company's environmental goal of reducing solid waste…". *Id*.

Staff agrees with the Company's position on the additional disallowances recommended by witness Coppola. The proposed projects address requirements of the ELG that are not under reconsideration by the EPA, and thus are necessary and reasonable for inclusion in rate base. However, Staff disagrees with the Company that the 'Monroe dry fly ash processing' project is shown to be of benefit to ratepayers as presented in this filing. The Company acknowledged the lack of internal approval for this project, stating that it expects to obtain final project approval in 2019, and that this project will provide economic benefits to ratepayers. (4 TR 600.) However, the Company did not address the lack of an executed contract and contracting strategy; the lack of a contract or even firm contracting strategy suggests that proposals received may not reflect the final cost and scope of the project. For these reasons, Staff was unable to evaluate with reasonable certainty the impact of this project on ratepayers. Staff believes that the Company has demonstrated this project's potential value for both Company and its ratepayers and encourages further development of this project. Staff recommends the disallowance of $34,100,000 in capital expenses associated with this project, and the Commission to direct the Company to present an updated NPV analysis once finalized contracts have been executed, if it seeks inclusion of this project in rates in a future rate case filing.

3. Staff recommends the Commission find that the combined heat and power plant proposed is reasonable for inclusion in the Company's rate base, for a total of $62,300,000 in capital expenditures.

The Company has included a proposed pilot combined heat and power (CHP) plant as part of its' filing. The Company provided testimony detailing the proposed CHP plant, which would be located on the Ford Motor Company's (Ford) research and engineering campus in Dearborn, MI, and would supply process steam to Ford, while generating electricity to be supplied to the Company's electric distribution system. (5 TR 1127-1128.) The Company will maintain ownership of the plant, while an affiliate, DTE Power & Industrial (DTE P&I), is contracted to design, construct and operate the facility. (5 TR 1130-1132.) Ownership of the plant will be transferred to the Company from DTE P&I when the plant is ready for commercial operation, with an expected completion date of December 31, 2019. (Exhibit A-40, Schedule DD-4; 4 TR 554.) Staff witness Jonathan DeCooman testified to Staff's review of the proposal, which included review of the supporting contracts and financial analyses. (8 TR 4192-4196.) Staff supports the CHP project as it will provide a net benefit to the Company's ratepayers, estimated by the Company as a present value savings of $102.1 million. (5 TR 1133-1134.) If the Commission does not find the Company's financial analysis adequate to determine the reasonableness of this project, the Commission could order the Company to competitively bid the construction of the plant. (8 TR 4196.) Company witness Robert Feldmann addresses Staff's recommendation by stating that seeking competitive solicitations is no longer possible, as construction of the plant began in March 2018. (5 TR 1138-1139.) The Company did provide a response to discovery indicating that if directed, the Company could solicit requests for information to companies experienced in the construction and operation of CHP units, in order to provide additional benchmarking of costs. (See Exhibit S-19.)

The AG and Michigan Environmental Council (MEC) both disagreed with Staff's position and recommended the proposed CHP plant be removed from the Company's rate base. MEC witness George Sansoucy contends that this project should not be considered a pilot, as DTE P&I will be operating the facility and has extensive knowledge from operations of similar plants. (6 TR 2683-2685.) Company witness Feldmann countered this assertion by stating that while DTE P&I has extensive experience with the operation of cogeneration assets, the Company is an independent affiliate and does not have access to DTE P&I's experience; since this project would be the first CHP plant in the Company's fleet, it should be considered a pilot. (5 TR 1141-1142.) Staff generally agrees that the project offers the

Company an opportunity to gain information regarding the use of CHP projects for large customers such as Ford, regardless of the project's pilot status. While DTE P&I has extensive knowledge in the construction and operation of CHP facilities, this would be the first facility of its kind on the Company's grid and would allow the Company to gain insights into its performance and the potential for use of this technology in the future.

Both witness Coppola and witness Sansoucy maintain the record provided lacks the transparency required to make a proper evaluation of the fair market value of this project. (5 TR 1639, 6 TR 2688.) Witness Feldmann disagreed, citing the 600 pages of contracts between Ford, the Company and DTE P&I, as well as the HDR estimate provided in Excel format with all formulas and supporting documents as evidence of the Company's transparency in this project. (5 TR 1139; Exhibit A-40, schedules DD-1 through DD-8.) While the Company did update the record with the inclusion of this data, if available this information should have been provided in the Company's initial application. Considering that these contracts and the HDR study were completed well in advance of the initial filing date, there is no easily identifiable reason why they were not. (See Exhibit A-40, Schedules DD-1 through DD-8 and Exhibit A-28, Schedule R2.) Providing this data in the initial application would have allowed for more transparency from the start of this proceeding and provided more time for parties to review these documents. In the future, Staff would strongly encourage the Company to be more proactive in the provision of supporting documents when proposing a project of this complexity.

After consideration of all parties' testimony, Staff concludes that the proposed CHP plant is reasonable for inclusion in the Company's rate base. Staff recommends the ALJ and Commission adopt its' position, if the Company's levelized cost of energy analysis and the HDR report are deemed adequate to establish the value of the asset. If this data is not considered adequate, Staff recommends the Commission direct the Company to seek requests for information to benchmark construction of a CHP with the equivalent specifications, location and infrastructure access, for comparison to the fixed-price contract and DTE P&I's book value at the time of the transfer of ownership of the CHP unit, and submit this information to establish a fair market value for this project.

4. Staff recommends reducing charging forward capital expenditures by $1,744,000.

Staff recommends reducing charging forward capital expenditures by $1,744,000, which is a $855,000 reduction to rate base. Staff witness Ozar recommended that Charging Forward infrastructure operations and maintenance (O&M) expenses be deferred and recovered through regulatory asset accounting. (8 TR 3410.) Based on his recommendations, Staff reduced corresponding Charging Forward capital expenditures.

5. Staff recommends reducing demand side management—programmable communicating thermostats capital expenditures by $9,593,000.

Staff recommends reducing demand side management—programmable communicating thermostats (PCT) capital expenditures by $9,593,000, which results in a $6,273,000 reduction to rate base. The Company is requesting $6.2 million in the 16 months ending 4/30/2019 and $3.4 million in the test year to purchase an additional 17,000 thermostats to enroll customers onto the PCT program. In the instant case the Company states that it has enrolled 2,000 customers on the PCTs since the launch of the program and expects to have 10,000 units by the summer of 2019. (3 TR 352.) In MPSC Case No. U-18014, the Commission agreed with Staff's recommendation to limit the Company to 10,000 PCTs until the Company has demonstrated that the existing PCTs are being used and stated, "[i]f DTE Electric demonstrates that its DR programs are successful in the initial phases, additional DR expenditures will be recoverable in a subsequent rate case" *In re DTE Electric Co Rate Case*, MPSC Case No. U-18014, 1/31/2017 Order, p 25.

In rebuttal, Company witness Dimitry disagrees with Staff's adjustment stating that the Company believes that its progress and success thus far in its PCT program justifies the Company's request for more expenditures to expand the program. (3 TR 385.) Witness Dimitry further states that during the summer of 2018, the Company called 4 PCT events where up to 1,597 customers participated in each event resulting in an average reduction of 1.05 kW per participating customer. *Id*. Ms. Dimitry states that customer enrollment should not be the sole indicator of initial success of a program stating that initial customer enrollments are not necessarily indicative of long-term program success. (3 TR 386.)

Staff does not believe that the Company has demonstrated to the Commission that it has been successful in its initial stages. In the Company's previous rate cases, U-18014, the Company's plan was to enroll 10,000 customers per year over the subsequent five years resulting in 50,000 customers enrolled. Following that case, in Case No. U-18255, Company witness Dimitry stated that the Company expects to enroll up to 10,000 customers by the end of 2017 and requested to purchase an additional 25,000 PCTs to continue to grow the program. While in the instant case Company witness Dimitry states that the Company has only enrolled 2,000 customers and is forecasting to have the initial 10,000 enrolled by year end 2018. (3 TR 381.) Through discovery Staff found that the Company has increased its enrollment in the PCT program to approximately 3,000 as of September 30th, 2018. (Exhibit S-12.3, p 5.) According to the same discovery response the Company expects to reach 4,500 enrollees by the end of the calendar year, which is well short of the expectations in the Company's previous rate cases. Staff agrees that customer enrollment is not a sole indication of a program's success, however it is an important indicator of success as it shows customers willing to enroll in the program. Program enrollment numbers should also be considered when purchasing devices to enroll said customers. It is important for the Company to purchase an appropriate number of PCT based on the customer enrollment requests and levels, as just having PCTs available for customers does not mean they will be enrolled in the program. Because the Company has failed to effectively complete its own enrollment goal in each of its previous rate cases, and because the Company has pushed its forecast of enrollment to later years in each case following its initial approval, Staff lacks confidence in DTE's commitment to the PCT program. Therefore, the ALJ and the Commission should adopt Staffs' recommendations to disallow $9.6 million for the Programmable Communicating Thermostat (PCT) Program.

6. The Commission should reduce the Company's information technology capital expenditures by $13,619,000.

The Commission should reduce the Company's information technology capital expenditures by $13,619,000, which reduces rate base by $7,971,000. Staff recommends adjustments to IT—corporate applications, IT—customer service projects, IT—plant and field projects, and IT—information technology for IT projects as described below.

a. Capital expenditures for the IT Corporate Applications—ConnectUs Phase 4 project should be reduced by $625,000.

Staff recommends a disallowance of $625,000 for the Company's projected capital expenditures for the ConnectUs Phase 4 project, which results in a $281,000 reduction in rate base. (Exhibit S-12.2). In its exhibit the Company states that this project's objective is enhance collaboration. (Exhibit A-12, Schedule B5.7.1, line 6.) When asked about how it will enhance collaboration, the Company stated that this platform will improve internal employee communications and efficiently elicit answers to questions through colleague responses, further stating that the spontaneity and real-time nature of such communications enables employees to stay up to date on emergent projects and company priorities. (Exhibit S-12.3, p 7.) Based on a lack of supporting evidence other than the fact that this project will allow the Company to communicate internally in a way similar to the way e-mail currently offers, Staff recommends the complete disallowance of this program. (8 TR 4150.)

In rebuttal, Company witness Griffin disagrees with Staff's analysis of the project stating that email has a built-in lag time. He states that there is limited ability for the group to interact with any of the other persons in the conversation in real time unless they are constantly monitoring their email. (5 TR 1399.)

While Staff does agree that there is a small amount of lag time when utilizing email, Staff also believes that a real-time social media platform is also only effective if the employee is constantly monitoring the social media platform. In the case that an employee is not constantly monitoring the social media platform, the ConnectUs phase 4 project is no different than an email-based system as the employees themselves are creating the time lag. Based on this reason, the ALJ and Commission should adopt Staff's recommended $625,000 disallowance for this project.

b. Capital expenditures for the IT Customer Service—Customer Digital Channels (MSA) Sustainment project should be reduced by $535,000 for the bridge period and $2,660,000 in the test year.

Staff recommends a disallowance of $535,000 from the bridge period, and $2,660,000 in the test year for the Company's projected capital expenditures for the Customer Digital Channels (MSA) Sustainment project. (8 TR 4150.) This translates to a $1,909,000 reduction in rate base. In its analysis Staff found that the Company forecasted this amount based on historical annual needs for supporting this program. (Staff Exhibit S-12.3 p 9.) The IT and technology sectors are a rapidly changing sector in both cost and ability. It is inappropriate to base an IT projection simply on what has been historically spent in a category. Staff understands that given the pace of technological advancements, it is difficult for the Company to accurately predict its technology needs and expenses several years into the future. But this difficulty, coupled with rapid changes in the field, is why the Commission should not approve funding for these expenditures based simply on a historical average rather than on detailed project information. For this reason, the ALJ and Commission should adopt Staffs disallowance of $535,000 from the bridge period, and $2,660,000 in the test year.

c. Capital expenditures for the IT Plant & Field—Work Management Sustainment (Maximo/ESri/Service Suit), Fuel Supply Sustainment, GenOps Business Sustain, IT FosGen Business Sustain, and Fermi—Nuclear Gen Sustain projects should be reduced by $542,000 from the bridge period, and $2,608,000 in the test year.

When asked for a more detailed breakdowns of the costs and proposed work included in these projects, the Company provided responses including the total expected costs for the included projects that were far below the amount requested in this case. (Staff Exhibit S-12.3, p 10-12.) For this reason, Staff is recommending the Commission limit the recovery of these programs to the amounts that DTE has shown in Exhibit S-12.3, pages 10-12, and disallow the costs above what the Company has provided explanations for in these audit responses. (8 TR 4152.)

In rebuttal, Company witness Griffin disagrees with Staff's assertion stating that the business cases for the projects are still in progress in accordance with the Company's annual planning cycle, with plans to finalize these projects in the 4th quarter. (5 TR 1361.) Witness Griffin further states that Staff's apparent assumption that the draft point-in-time documentation represented the final version is fundamentally faulty. (5 TR 1410.)

Staff disagrees with the Company's logic that projects should be approved before final information about them is known. Here, the Company is asking for recovery of costs for projects that are still in the planning phase. *Id.* This lack of information about the project due to the Company's own planning timeline is not a risk that ratepayers should be responsible for simply because of the timing of when the Company chose to file its case. Staff did reference the version of the documents the Company presented in this case as final. This was the information that the Company had available at the time. Staff must use the information made available to them to make its determination of prudency. Based on the information the Company provided to Staff, the Company has not shown that the expenses included in its audit responses (Staff Exhibit S-12.3, p 10-12) are reasonable and prudent at this time. For this reason, the ALJ and Commission should adopt Staffs disallowance of $542,000 from the bridge period, and $2,608,000 in the test year.

d. Capital expenditures for the IT Customer Service—IT Business Planning and Development Sustainment and IT—Information for Technology IT—2018 Emergent, and coDE Sustainment projects should be reduced by $2,813,000 from the bridge period, and $3,837,000 in the test year.

Staff recommends a disallowance of $2,813,000 from the bridge period, and $3,837,000 in the test year for the Company's projected capital expenditures for the IT Business Planning and Development Sustainment, 2018 Emergent, and coDE Sustainment projects. (Exhibit S-12.2.) Staff recommends the disallowance of all the projected costs of these projects minus the costs incurred to date. In its analysis Staff found that these projects are all based on emergent needs. (Exhibit S-12.3 p 8, Exhibit A-12, Schedule B5.7.5 lines 4-5.) Staff's recommendation comes from considering the nature of an emergent work coupled with a future looking test period and the guaranteed recovery of these projections once approved, it is inappropriate for the Company to recover these costs in rates given the uncertainty of these projects.

In its rebuttal testimony the Company disagrees with Staff's assessment of the projects stating that the Company has an annual planning cycle during which the Company prioritizes, approves and undertakes IT related Projects which concludes in the last quarter of a given year. (5 TR 1402.)

Staff is correct to recommend a disallowance of these costs. The Company has chosen to file a rate case application knowing that it has not completed its annual planning cycle on these projects. While Staff understands that planning is an important part of the project process, it is inappropriate to approve funds for projects where the planning phase is not complete, and many parts of a project may change including scope and cost. Given the uncertainty of these projects at this time Staff correctly recommends a disallowance of $2,813,000 from the bridge period, and $3,837,000 in the test year for the Company's projected capital expenditures for the IT Business Planning and Development Sustainment, 2018 Emergent, and coDE Sustainment projects.

7. The ALJ and Commission should adopt Staffs suggestion about how the Company should represent IT expenditures in future cases.

Staff's direct testimony provided a description of information that should be filed with its IT investments in future cases. (8 TR 4152.) The purpose of this request was to provide Staff and intervenors more information about IT programs upfront to allow Staff and intervenors to perform a stronger prudency analysis.

The Company's rebuttal witness Griffin agrees to most of Staff's recommendations but includes modifications regarding the structure of Staff's suggestions. (5 TR 1412.) However, Mr. Griffin disagrees with one suggestion: that the Company breakdown 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 and include an explanation of why the project was not completed or why it was off budget. (5 TR 1417.)

Staff agrees with most of the modifications of Staff's recommendations that the Company made for its filing requirements. Staff believes that the Company should be held accountable for its projections in its IT programs and should show that programs are not only being funded and completed, but also being done within budget. Staff's final recommendation of providing a breakdown of any IT programs that were approved in its previous rate case that were not completed or were 20% above or below the approved project amount will provide Staff and the Commission the assurance necessary to see that DTE is completing its preapproved projects in a timely manner and within budget. For this reason, the ALJ and Commission should adopt Staffs recommended filing suggestions with DTE's modification for all but Staff's final recommendation. As to Staff's last recommendation for IT programs, which Mr. Griffin disagreed with, Staff urges the ALJ and Commission to adopt that recommendation because it will go a significant way towards providing assurances that approved programs were being completed within budget. (8 TR 4152-4153.)

8. The ALJ and Commission should adopt Staff's proposed disallowance of $8.45 million for the Company's 3G to 4G communication upgrade program.

In its filing the Company is requesting $10,344,000 to upgrade its AMI cellular network from a 3G network to a 4G network. (8 TR 3955.) The Company states that it has approximately 3300 cellular 3G cell relays integrated within its AMI system (8 TR 3957) that need to be replaced to maintain the viability of the Company's mesh network. As shown in Staff's Exhibit S-12.3, page 1, the Company installed 3,000 3G cell relays in its territory to support its AMI mesh network. In the instant case the Company is requesting additional cell relays to strengthen its mesh network and improve its read rates. (Staff Exhibit S-12.3, p 2.) Staff's recommendation is to disallow all costs associated with the additional relays over the 3,000 the Company initially installed as the Company's AMI infrastructure was functional and the Company has a meter read rate through 2017 of 98.51%.

In his testimony Staff witness Evans proposed a disallowance that included the Company's 3G to 4G communication upgrade. (8 TR 4102.) In order to avoid duplicate disallowances, Staff has only included witness Evans adjustments in Staff's Exhibit S-1 Schedule A1.

In rebuttal, Company witness Robinson disagrees with Staff's calculation stating the material for the project is the largest contributor of almost $26 million. The material cost of the project reflects a turn key solution with a hardware vendor. This includes the cost of the hardware, most of the installation labor, and material. The $26 million divided by 3,300 cellular relays results in a per relay cost of approximately $7,900. (8 TR 3966.) The Company further states that based on its benchmarking with other utilities the Company's read rate is below its peers. The Company's goal is to reach a 99.5% read rate. (8 TR 3966.)

Staff reasserts that its calculation of its disallowance is correct given the information that the Company provided in the instant case. Staff used the $6,000 per cell relay shown in CSM-8.7 to calculate that the Company should have $18,000,000 in costs to purchase the cell relays. Staff then took this number from the $26,000,000 in material costs shown in Staff's Exhibit S-20, resulting in a disallowance of $8,000,000. In calculating the installation costs, Staff took the Company's proposed installation cost of $5,000,000 and calculated a cost per relay to install totaling $1515. Staff then took that cost and multiplied it by the 300 cell relays it is recommending for disallowance and found that value to be $454,500. Staff's calculations are based on the information the Company provided in audit response and is the best information that was made available to Staff. Concerning the Company's goal of 99.5% read rate, Staff believes that simply removing the cell relays from customers' homes, where they are located under the tree line to the new pole mounted cell relays will provide increased network strength by itself. The addition of 300 new relays at a cost of $8.5 million for a 1% increase in read rates does not represent a prudent expenditure. For these reasons, if in the instant case the Commission does not accept Staff witness Evans adjustments to this line item, Staff urges the ALJ and Commission to adopt Staff's proposed disallowance of $8.450 million for the Company's 3G to 4G communication upgrade program.

9. The ALJ and Commission should adopt Staff's recommendation for the Company to replace the meters of all electric customers currently electing service under the Company's Non-Transmitting Meter Provision (DTE Electric tariff C5.7) with digital meters that are not capable of transmitting any signals.

In this case, Staff witness Matthews performed an analysis of whether there is improper radio transmission by opt-out AMI meters pursuant to the Commission order in case number U-18203. *In re Commission's own motion to review issues concerning cybersecurity and the effective protection of utility infrastructure*, MPSC Case No. U-18203, 6/28/2018 Order, pp 5-6. Throughout its investigation, Staff found that some AMI opt-out customers still have functioning radios after the Company allegedly disabled radio transmitters. In response to a Staff audit question (Exhibit S-12.3. p 3.), the Company stated that as of August 10th, 2018 there were 267 customers with opt-out meters that were still communicating, and the Company has provided credits to 246 of those customers identified as of August 10th. (Exhibit S-12.3. p 4.) Because the Company has discovered that it has opt-out customers with radios that continue to transmit after the Company has performed its procedure to disable the radios, and in order to ensure that this does not continue into the future, Staff recommends that the Company replace the meters of all electric customers currently electing service under the Company's Non-Transmitting Meter Provision with digital non-transmitting meters.

In rebuttal, Company witness Robinson stated that If the Commission approved the settlement agreement in case number U-20084, then the Company would implement the AMI to digital meter changeout as recommended by Staff and set forth in the agreement. (8 TR 3968.) Further stating that if the Commission rejected the settlement than the Company has other avenues to address the issue and should therefore not be bound by an unapproved settlement agreement. (8 TR 3968.)

On December 20th, 2018 the Commission approved the settlement agreement in DTE's show cause. *In re DTE Electric and DTE Gas to show cause*, MPSC Case No. U-20084, 12/20/2018 Order, p 3. Because the Commission approved the settlement agreement, the Company and Staff agree that the Company will replace the meters of all electric customers currently electing service under the Company's Non-Transmitting Meter Provision (DTE Electric tariff C5.7) with digital meters that are not capable of transmitting any signals.

10. The ALJ and Commission should adopt Staff's recommendation for DTE to explore shadow billing.

In its testimony, Staff recommends that the Company explore shadow billing capabilities for inclusion in its next rate case. (8 TR 4146.) Staff describes shadow billing as the practice that calculates a customer's bill using their actual, historic billing determinants as if the customer were on a different rate, such as a time-of-use rate. (8 TR 4146.) Shadow billing helps customers understand different rates and make a more informed decision.

The Commission has previously addressed shadow billing in its March 29, 2018 Order in Consumers Energy's recent electric rate case. *In re Consumers Energy's Electric Rate Case*, MPSC Case No. U-18322, 3/29/2018 Order, pp 77-78.

In that case, the Commission was supportive of a continued investigation into implementing shadow billing and/or a trial period to increase customer understanding and evaluation of demand response rates.

In rebuttal, Company witness Clinton disagrees with Staff's recommendation on shadow billing stating that the Company does not agree that shadow billing is the appropriate tool given the precise and complex calculations needed to render an alternative bill. (6 TR 2120.) The Company further states that it is not convinced that backwards looking shadow billing functionality is helpful. *Id.*

Staff stands by its initial recommendation that DTE should explore shadow billing, as it does provide the customers with more information about their own energy usage rather than a theoretical energy use. Staff disagrees with the Company in that backwards looking shadow bill functionality would not be helpful. It is important for a customer to learn about a rate before enrolling in that rate. It is easier for a customer to see how their actual usage on a rate would affect their bill than to see how their bill would theoretically change under a new rate. For this reason, it is important for the Company to use actual billing determinants when doing any kind of rate calculator. Staff believes strongly that shadow billing is the correct tool that will invigorate customer commitment to different rate programs offered by the utility such as time-of-use structured rates.

11. The ALJ and Commission should adopt Staff's recommendation to remove the marketing and educational costs associated with altering customers usage from its proposed regulatory asset for summer on-peak rates.

In its case, the Company included a proposal to include the costs necessary to implement summer on-peak rates in a regulatory asset. (7 TR 3338.) The Company is requesting that deferral accounting treatment be used not to exceed $45 million of which $9 million would be used for customer education expenses. (7 TR 3339.)

Staff supports the Company's request to implement its summer on-peak rates as discussed in Staff witness Revere's testimony and include those costs in a regulatory asset to be reviewed prior to its inclusion in rates as discussed by Staff witness Gerken. (8 TR 4147.) Staff asserts that no marketing or education costs for the purpose of altering customer use should be included in the regulatory asset for this program. *Id.* The intention of the summer on-peak rate is not to illicit a response from customers, as a Demand Response program is intended to do. Rather, the summer on-peak rate is intended to better reflect the costs that residential customers cause on the system in the summer months.

In rebuttal, Company witness Clinton disagrees with Staff stating that a rate change of this scale will require education and outreach to inform its customers. (6 TR 2126.) Witness Clinton further states that not providing education of any kind will lead customers to question the trustworthiness of the Company's actions and the value of the rate structure change. (6 TR 2127.)

While Staff agrees that the Company will need to provide outreach and education generally about the rate structure and why the transition is being done, Staff stands by its recommendation that educational costs, specifically about altering usage, should not be included in this regulatory asset. The costs that should be included in the asset are the costs necessary for a transition into the new rate structure. These costs would include educational costs for informing its customers about what the rate is and how it works. Staff does not intend for this regulatory asset to include costs for the Company to design a large-scale demand response program. For this reason, the ALJ and Commission should adopt Staff's recommendation to remove the marketing and educational costs associated with altering customers usage from its proposed regulatory asset for summer on-peak rates.

12. Staff recommends a $74,188,000 reduction to distribution plant capital expenditures.

Staff recommends a $74,188,000 reduction to distribution plant capital expenditures, which is a $55,663,000 reduction to rate base. The specific disallowances that result in this total $74.188 million disallowance are discussed below.

a. The Staff initially recommended the Commission disallow $88,615,000 from the 2017 historic year distribution capital expenditures, but now recommends those expenditures be included in rate base.

The Company is requesting recovery of $651,372,000 in distribution capital expenditures for the 2017 historical year. (Exhibit A-12, Schedule B5.4.) The Staff now recommends no adjustments to these expenditures. Company witness Marco A. Bruzzano's rebuttal testimony provided information that was missing from the initial filing regarding over-spending that occurred in the 2017 historical year.

The Company's failure to acknowledge and discuss the over-spending was the basis for initially recommending disallowance of $88.615 million from the $651.372 million. By Staff's calculation, the Company spent $88.615 million more on distribution plants in 2017 than was authorized by the Commission in its April 18, 2018 Order. (8 TR 4102-4103.) As Staff witness Nicholas M. Evans acknowledged in his direct testimony, spending beyond what the Commission authorizes is not always imprudent or unreasonable. Sometimes a project or program warrants higher-than-authorized spending. However, if the Company over-spends its Commission authorization in a major category, like distribution plant, the Company needs to justify this higher spending in the next rate case. (8 TR 4103.) Specifically:

> The Company should provide to Staff a list of the programs that were the major contributors to the over-spending, the amount of over-spending that occurred, a list of equipment purchased, an explanation as to why the over-spending for each program needed to occur, and an explanation as to why the spending could not be deferred until a later year. [8 TR 4108.]

During its review of the Company's testimony and exhibits in the instant case, Staff came to the conclusion that DTE Electric had provided none of these items in its filing. The over-spending was not even acknowledged. Staff spotted the discrepancy between anticipated and actual spending on 2017 distribution plant, performed an analysis to determine the category in which over-spending occurred ("Emergency Retirement Unit Changeouts and Storm" in Case No. U-18255, which became "Emergent Replacements" in the instant case) and calculated the degree of over-spending. Yet, when Staff witness Nicholas M. Evans filed his direct testimony, Staff did not know what equipment or items were purchased, why the over-spending occurred and, why it had to occur in 2017. (8 TR 4107.)

Mr. Bruzzano's rebuttal testimony filled in these blanks. The 2017 spending occurred in large part to respond to the March 8, 2017 historic storm; the spending was primarily for poles, wires and labor; and it could not have been deferred because if the Company had not responded to the storm, customers would have been left without power and electrical system risks and hazards would not have been addressed in a timely manner. (4 TR 823-824, 829, 836.) Staff accepts this explanation and recommends full recovery for 2017 distribution capital expenditures.

Although Company witness Bruzzano did provide relevant information regarding 2017 spending in rebuttal testimony, he also criticized Staff's disallowance. The Company made the following statement regarding Staff's initial disallowance of 2017 historical expenditures:

> A *cap* on Emergent Retirement Unit Changeouts and Storm (or Emergent Replacements as they are described in this case) would pose a challenge to the Company's ability to do this, slowing the response process. (emphasis added.) [4 TR 828.]

In addition, the Company asserts that it must have the discretion to invest capital in excess of the amount included in rates when restoring customers. (4 TR 831.)

In response, Staff would like to point out that Staff witness Evans did not, in his direct testimony, propose a cap on the Company's spending or advocate limiting the Company's discretion to invest capital. Staff witness Evans only advocated that over-spending in the historical test year be supported. (8 TR 4107-4108.)

The Company also criticized Staff's recommendation that the Company be directed to notify the Staff before a significant over-spend of Commission-approved electric distribution capex occurs. Company witness Don M. Stanczak states that this recommendation is a substantial change to the current regulatory construct and that it would be wholly inefficient, if not entirely inappropriate, that investment decisions be subject to pre-review and/or pre-approval from the Commission Staff. Mr. Stanczak recommends Staff's proposal be rejected. (3 TR 99.)

Staff sympathizes with the Company's concerns in this matter and hereby modifies its original recommendation: the Company should notify Staff *either before or after* significant overspending in a major category, like distribution capital, occurs. Notification need not be formal. This purpose of this notification would be to alert Staff that spending is high in a major category. Staff is not proposing that any capital spending be subject to pre-review or pre-approval, Staff is not recommending a cap on spending of any sort be placed on the Company, and Staff is not trying to manage the day-to-day operations of the Company.

In its rebuttal testimony, the Company tries to create the impression that most of the information to support the 2017 overspending was included in the filing, and that Staff should have been aware of any information not included. In his direct testimony, Company witness Bruzzano mentioned the March 8, 2017 storm and provided a sentence describing how much wire and poles were replaced in 2017. (4 TR 797, 780.) The Company also provided, as part of the Part III filing requirements, the cost of the March 8, 2017 storm and a list of equipment replaced for storm restoration in 2017. Mr. Bruzzano also describes, in his rebuttal testimony, the Company's report on the March 8, 2017 storm, filed as part of Case No. U-18346. He states that:

> [T]he report associated with MPSC Case No. U-18346, which was filed in May 2017, could have been viewed by the Commission and Staff as a clear early indication that expenditures for Emergency Retirement Unit Changeouts and Storm would be much higher than what was forecasted at the time of submittal of Case U-18255. [4 TR 837.]

While some information relating to the 2017 overspending was provided, what was lacking was an acknowledgement of the over-spending and a narrative that explained why the over-spending occurred and why it was reasonable and prudent. Without this narrative, Staff could only make educated guesses regarding the underlying details of the overspending.

Staff should also not be expected to research other dockets and cases in order to find an explanation for an expenditure. Staff is not obligated to send a discovery request every time it finds information missing in the Company's case. The Company has the responsibility to support its case and shoulders the burden of proof in this proceeding.

In his rebuttal testimony, Company witness Don M. Stanczak stated:

> Hindsight should not be used in the rate setting process to reconcile the difference between projected expenditures from a prior rate case against actual expenditures incurred in a historical period. Rather, the Company's test period expenditures should be evaluated for reasonableness and prudence. [3 TR 97.]

In response to this, the Staff urges the Commission to view significant over-spending in a historical year as unvetted, unaudited spending that should receive the same scrutiny as projected capital expenditures in the test year. The over-spending is above and beyond the amount deemed reasonable and prudent by the Commission in the last rate order, so these expenditures cannot be considered reasonable and prudent until the Commission issues an order in which they are declared as such. That the expenditures occurred in the historical year does not make them special, and the same standard of proof—preponderance of the credible evidence—should apply to them.

In this case, the Company provided the information that was missing from the initial filing regarding over-spending that occurred in 2017, and Staff now believes the 2017 capital expenditures are reasonable and prudent.

b. The Staff initially recommended the Commission disallow $64,455,000 from calendar year 2018 distribution capital expenditures, but now recommends $19,223,000 be disallowed.

Staff is recommending that capital expenditures for 2018 distribution plant be adjusted downward so that the projection reflects the actual spending among its constituent categories. The Company is currently projecting $810,157,000 for 2018—$202,104,000 for Emergent Replacements; $201,921,000 for Customer Connections, Relocations, and Other Net of Contributions in Aid of Construction ("Connections & Other"); and $406,132,000 for Strategic Capital. (Exhibit A-12, Schedule B5.4.) Exhibit A-31, Schedule U-7, filed with the rebuttal testimony of Company witness Marco Bruzzano, shows actual expenditures in these categories for January through October 2018. As of October 31, the Company had spent more than projected in Emergent Replacements and less than projected in Strategic Capital. Spending on Connections & Other was basically on track. (Exhibit A-31, Schedule U-7.)

Since Staff now knows the distribution capital spending for the first 10 months of 2018, Staff must forecast Company spending during the last two months of the year. The Company provided its own forecast in Exhibit A-31, Schedule U7. The Company did a straight-line extrapolation of January – October 2018 spending to arrive at a 2018 total for each distribution capital category. The Company's grand total for distribution capital is $816,724,000. (Exhibit A-31, Schedule U-7.) Staff agrees with all of the forecasts except for the projection for Emergent Replacements.

The Company spent $297,370,000 on Emergent Replacements from January through October 2018. Using the straight-line extrapolation methodology (multiplying by 12/10 or 1.2), the total 2018 spending in this category would be $356,844,000. (Exhibit A-31, Schedule U-7.) This amount is simply too high and assumes that the higher-than-forecasted spending in Emergent Replacements will continue in November and December. However, spending for the Emergent Replacements category is somewhat volatile. Looking at Exhibit A-12, Schedule B5.4, page 3, lines 7, 14, and 21, it is apparent that costs fluctuated up and down over the 2013-2017 period: for 2013, the total Emergent Replacement cost was $166,596,000; for 2014, $187,547,000; for 2015, $179,660,000; for 2016, $183,380,000; and for 2017, $284,270,000. It is logical to assume that these expenditures can also fluctuate on a month-by-month basis. Applying this assumption to 2018, it follows that just because monthly spending has been higher than forecasted for January through October, it does not mean that spending in November and December is destined to also be higher than forecasted. Spending in these two months could be close to their original forecast ($16,842,000 per month) or even lower, creating a drop from October to November like the decrease in spending that occurred from 2014 to 2015. (Exhibit S-10.7.) This possibility should be presented as the forecast for November and December 2018.

Thus, the amounts Staff chose for November and December were simply the Company's filed projections for those months: $16,842,000 for November, $16,842,000 for December. (Exhibit S-10.7.) Adding these amounts to the

$297,370,000 spent from January – October 2018 produces a new 2018 forecast of $331,054,000.

Staff then added this amount to the extrapolated amounts for Connections & Other, Resilience and Hardening, Redesign, Technology, and Miscellaneous, all of which are shown in Exhibit A-31, Schedule U-7, page 3, column (d), lines 7-11. This results in a new total forecast of $790,934,000 for distribution capital expenditures in 2018. The difference between this amount and the Company's projection of $810,157,000 is $19,223,000, which Staff is recommending be disallowed.

Staff's original disallowance for 2018, presented in the Direct Testimony of Nicholas M. Evans, was $64,455,000. (8 TR 4101.) This was the net result of four downward adjustments to the Strategic Capital category and two upward adjustments to the Emergent Replacements category. (8 TR 4117.) Staff's new $19,223,000 disallowance is the result of using updated 2018 spending numbers for the Strategic Capital sub-categories and the Connections & Other category, eliminating the Substation Risk: Drexel disallowance, keeping the Emergent Replacements January – August 2018 overspend, increasing the Emergent Replacements September – December 2018 upward adjustment, and including the negative spending on miscellaneous items.

c. Staff initially recommended the Commission disallow $31,447,000 from the first four months of 2019 distribution capital expenditures and $61,894,000 from the test year, but now recommends $21,912,000 be disallowed from the first four months of 2019 and $33,053,000 be disallowed from the test year.

The Company is currently projecting $285,557,000 for the first four months of 2019—$67,933,000 for Emergent Replacements; $71,845,000 for Connections & Other; and $145,779,000 for Strategic Capital. The Company is projecting $830,578,000 for the test year—$204,580,000 for Emergent Replacements; $193,059,000 for Connections & Other; and $432,939,000 for Strategic Capital. (Exhibit A-12, Schedule B5.4.) Staff recommends that capital expenditures for distribution plant that are projected to be incurred from January 1, 2019 to April 30, 2020 be adjusted downward. Given that spending on the Strategic Capital category is behind in 2018, Staff believes it prudent to assume that spending in this category will continue to fall short of projections in the 16-month period following 2018. Staff also believes the Company will be able to ramp up spending to some degree on the Strategic Capital category in 2019 and into 2020, so the annual shortfall should be less than what Staff is predicting for 2018. (8 TR 4118.) Staff also thinks it is reasonable to believe that spending on the Emergent Replacements category will be significantly less in 2019 and 2020 than what Staff is forecasting for 2018. Staff believes spending on Emergent Replacements will be close to the 2013 – 2017 five-year average in 2019 and 2020. Spending on the Connections &

Other category will likely be similar to the Company's projections, since 2018 spending is tracking closely with the projection. *Id.*

Based on these guidelines, Staff believes the Company will spend at least $790,934,000 for distribution capital expenditures in 2019, which is the same amount as Staff's projection for 2018. (Exhibit A-44.) Inflating this 2019 amount by Staff's 2020 inflation rate of 2.50% but only including four months of spending provides $270,236,000 for the first four months of 2020. Staff adopts these amounts for total distribution capital expenditures for January 1, 2019 – April 30, 2020. The $21,912,000 disallowance for the first four months of 2019 is the difference between the Company's projection of $285,557,000 and Staff's projection of $263,645,000, which is Staff's 2019 distribution capital expenditures of $790,934,000 pro-rated for four months (divided by three). The $33,053,000 test year disallowance is the difference between the Company's projection of $830,578,000 and Staff's test year projection of $797,525,000. Staff's test year projection was calculated by adding eight months of Staff's 2019 projection ($527,289,000) to Staff's projection for the first four months of 2020 ($270,236,000).

Staff's disallowances are reasonable when expenditures are allocated to the different distribution expenditures categories. For the first four months of 2019, the Company is projecting $67,933,000 for Emergent Replacements and $71,845,000 for Connections & Other. (Exhibit A-12, Schedule B5.4.) Staff finds these amounts reasonable. Using Staff's projected distribution capex for the first four months of 2019, ($263,645,000), leaves $123,867,000 for Strategic Capital. Since the Company is projecting $145,779,000 for Strategic Capital during this period, the Staff is recommending for the first four months of 2019 that the Company recover 85% of its projection for this category.

For the test year, the Company is projecting $204,580,000 for Emergent Replacements and $193,059,000 for Connections & Other. (Exhibit A-12, Schedule B5.4.) Staff finds these amounts reasonable. Using Staff's projected distribution capex for the test year, ($797,525,000), leaves $399,886,000 for Strategic Capital. Since the Company is projecting $432,939,000 for Strategic Capital during this period, Staff is recommending for the test year that the Company recover 92.4% of its projection for this category.

Staff's projections for Strategic Capital for the January 1, 2019 – April 30, 2020 period are reasonable. For 2018, the Company is on track to spend $258,745,000 of the projected $406,132,000, or 63.7%. If one assumes that actual spending in Strategic Capital from January 1, 2019 – April 30, 2020 will be greater than 63.7% but no more than 100% of the Company's forecast for that time period, a reasonable "middle ground" can be calculated to be halfway between 63.7% and 100%, or 81.9%. This 81.9% would embody the possibility that spending will still be slower in the Strategic Capital category but also that the Company will be able to ramp up spending in that category. Any projection calculated by Staff should be greater than or equal to 81.9%.

Since Staff's projections for the first four months of 2019 and the test year are both greater than 81.9%, Staff's projections for Strategic Capital are reasonable, even generous. In his direct testimony, Staff witness Nicholas Evans used the same method to test the reasonableness of the amounts he was recommending at that time. (8 TR 4123-4125.)

The Commission should be aware that Staff does not believe the Company will be able to spend 100% of its Strategic Capital forecast in the January 2019 – April 2020 time period even if the Company's forecasts in the other two major categories, Emergent Replacements and Connections & Other, turn out to be accurate. The reason is simple—even though some of the under-spending in Strategic Capital that occurred in 2018 was attributable to funds being diverted to Emergent Replacements, this amount was relatively small. Looking at page 10 of Exhibit S-10.4, there were four projects where under-spending occurred to support Emergent Replacements along with hurricane restoration efforts. This under-spending totals $8,832,000, which is calculated by adding together the totals in column (d), lines 18, 19, 20, and 23. Since this amount includes hurricane restoration funds, the actual amount diverted to Emergent Replacements is less than $8,832,000. For comparison, the Company will likely fall $147,388,000 short of its projection for Strategic Capital in 2018, which is calculated by adding together the amounts in lines 8-10, column (e), on page 3 of Exhibit A-31, Schedule U-7. Therefore, diversions to Emergent Replacements were responsible for only a small portion of the shortfall in spending on Strategic Capital in 2018.

The other reasons for the shortfall were discussed in the direct testimony of Nicholas Evans and are contained in Exhibit S-10.4—projects deferred, delayed, or postponed due to local permitting issues, land availability, or other reasons; the project is awaiting approval from Army Corps of Engineers; and the project design is not approved by the local government. These issues caused the bulk of the under-spending in Strategic Capital in 2018.

While Staff believes that the Company will overcome many of these challenges in 2019 and beyond, the Commission should make adjustments to distribution capital because these issues could persist into, or crop up again, in 2019. Staff's recommended disallowances of $21,912,000 from the first four months of 2019 and $33,053,000 from the test year are reasonable disallowances for the Commission to adopt given these circumstances.

d. Staff recommends numerous reporting requirements for distribution plant.

In his direct testimony, Staff witness Evans recommended that several reports or updates be filed by the Company by May 31, 2019, and by March 31 every year thereafter:

> 1) A timeline that shows when individual circuits or substations will be hardened or converted to 13.2 kV over the next five years and provide an updated report every following year.
>
> 2) Disclosure of how much money was spent on hardening, the amount of vegetation funds spent on hardening, the number of miles trimmed for hardening, the names of circuits hardened, how many miles of circuits were hardened, how many miles of arc wire were removed, why more or less arc wire was removed than planned, changes in procedures (if any), changes in plan for the upcoming year, the number of poles replaced, the number of poles retired, the number of cross arms replaced, and how many miles of wire were replaced.
>
> 3) A tabulation of how many miles of arc wire were removed under the following programs: 4.8 kV Hardening Program, System

> Resiliency Program, the 4.8 kV Conversion Program, the Frequent Outage (CEMI) Program, and other planned capital work. [8 TR 4126.]

> Staff had several other recommendations:

> Staff recommends the Company maintain a minimum of ten years between the 4.8 kV Hardening Program and any conversion program. Under this proposal, substation areas that are not expected to be converted to 13.2 kV within the following 10 years can be considered for the 4.8 kV Hardening Program, and substation areas that are scheduled for conversion within 10 years cannot be considered for hardening. [8 TR 4126-4127.]

The Company agreed to most of these recommendations in the Reply to the MPSC Staff's Response to DTE Electric's Arc Wire Report, filed on August 31, 2018 in Case No. U-18484.

13. The ALJ and Commission should adopt Staff's proposed disallowance of $8.45 million for the Company's 3G to 4G communication upgrade program.

In its filing the Company requested $10,344,000 to upgrade its AMI cellular network from a 3G network to a 4G network. (8 TR 3955.) The Company states that it has approximately 3300 cellular 3G cell relays integrated within its AMI system that need to be replaced to maintain the viability of the Company's mesh network. (8 TR 3957.) As shown in Staff Exhibit S-12.3, page 1, the Company installed 3,000 3G cell relays in its territory to support its AMI mesh network. The Company is now requesting additional cell relays to strengthen its mesh network and improve its read rates. (Exhibit S-12.3. p 2.) Staff's recommendation is to disallow all costs associated with the additional relays over the 3,000 the Company initially installed as the Company's AMI infrastructure was functional and the Company has a meter read rate through 2017 of 98.51%.

Staff witness Evans' testimony proposed a disallowance that included the Company's 3G to 4G communication upgrade. (8 TR 4102.) In order to avoid duplicate disallowances, Staff has only included witness Evans adjustments in Staff's Exhibit S-1 Schedule A1.

In rebuttal, Company witness Robinson disagrees with Staff's calculation stating the material for the project is the largest contributor of almost $26 million. The material cost of the project reflects a turn key solution with a hardware vendor. This includes the cost of the hardware, most of the installation labor, and material. The $26 million divided by 3,300 cellular relays results in a per relay cost of approximately $7,900. (8 TR 3966.) The Company further states that based on its benchmarking with other utilities the Company's read rate is below its peers. The Company's goal is to reach a 99.5% read rate. *Id.*

Staff reasserts that its calculation of its disallowance is correct given the information that the Company provided in the instant case. Staff used the $6,000 per cell relay shown in Exhibit S-20, p 2, to calculate that the Company should have $18,000,000 in costs to purchase the cell relays. Staff then took this number from the $26,000,000 in material costs shown in Staff's Exhibit S-20, p 1, resulting in a disallowance of $8,000,000. In calculating the installation, Staff took the Company's proposed installation cost of $5,000,000 and calculated a cost per relay to install of $1515. From this, Staff took that cost and multiplied it by the 300 cell relays it is recommending for disallowance and found that value to be $454,500. Staff's calculations are based on the information the Company provided in audit response and is the best information that was made available to Staff. Concerning the Company's goal of 99.5% read rate, Staff believes that simply removing the cell relays from customers' homes, where they are under the tree line to the new pole mounted cell relays will provide increased network strength by itself. The addition of 300 new relays at a cost of $8.5 million for a 1% increase in read rates does not represent a prudent expenditure. For these reasons, if in the instant case the Commission does not accept Staff witness Evans adjustments to this line item, Staff urges the ALJ and Commission to adopt Staff's proposed disallowance of $8.450 million for the Company's 3G to 4G communication upgrade program.

IV. Capital Structure and Rate of Return

A. Capital Structure and Overall Rate of Return

Staff recommends an after-tax overall rate of return of 5.45%, which consists of a recommended return on equity (ROE) of 9.80% and an equity percentage of 51.0%. (8 TR 4066.) Staff's overall rate of return recommendation is less than the Company's 5.76% after-tax overall rate of return recommendation by about 21 basis points due to DTE Electric's higher 10.50% ROE recommendation in this case. (6 TR 1919.) Company witness E. J. Solomon sponsors DTE Electric's capital structure and overall rate of return testimony. (5 TR 1036-1058.) Company witness Dr. Michael Vilbert sponsors DTE Electric's ROE recommendation. (6 TR 1912-2008.) Dr. Vilbert submitted rebuttal testimony disputing portions of Staff's ROE analysis and 9.80% recommendation. (6 TR 2009-2057.) The Attorney General's (AG) witness Sebastian Coppola recommends a 9.50% ROE with a 50% equity percentage. (6 TR 1594.) The Association of Businesses Advocating Tariff Equity's (ABATE) witness Christopher Walters recommends a 9.30% ROE. (7 TR 2954.) Witness Walters submitted rebuttal disputing Staff's agreement with the Company's proposed 51% equity layer.[8] (7 TR 3028.) Staff will summarize its capital structure development and cost of equity analysis, and then address any rebuttal arguments from the Company and other intervenors.

B. Capital Structure Development

1. Staff agrees with the Company's recommended balances for common equity, long-term and short-term debt, preferred stock, job development investment tax credits and net deferred income taxes.

Staff agrees with the Company's revised balances and cost rates and/or the recommended balances and cost rate methodology for all the capital structure components, except ROE. (8 TR 4069-4070.) (See also Exhibit S-7.4, pp 1-4.) The revision stems from a formula error that understated its deferred income tax balance by $97.3 million. To account for this error, the Company reduced its recommended long-term debt, short-term debt and common equity balances by a weighted percentage amount up to $97.3 million and increased its deferred income

---

[8] Mr. Walters' direct testimony disagreed with the Company's recommended 51% equity layer but provided no alternative equity layer recommendation. In rebuttal, he also disputed Staff's agreement with the Company's equity layer recommendation but did not indicate an alternative recommendation.

tax balance by the same amount. Staff agreed to these revisions and modified its recommended balances accordingly.

C. Return on Common Equity Development

1. Staff's Overall Analysis

Staff recommends a ROE range of 9.00% to 10.00% and used 9.80% as its recommended ROE in its overall cost of capital determination. (8 TR4066.) Staff relied on the guidelines set forth by the Supreme Court in the *Hope* and *Bluefield* decisions in determining a reasonable ROE for DTE Electric. (9 TR 4071.) Staff used a group of 11 publicly traded electric utility companies to help establish a reasonable cost of equity range for the Company. Staff used five criteria to establish its proxy group: 1) net plant greater than $4 billion but less than $40 billion to better compare to the size and footprint of DTE Electric; 2) approximately 50% or more of its revenues from regulated electric service; 3) an investment grade credit rating from Standard & Poor's (S&P) and Moody's; 4) currently paying dividends to shareholders; and 5) not involved in any merger or corporate buyout of a utility company. (8 TR 4072.) The proxy group's statistics were used to provide a reasonable approximation of the Company's required cost of equity in Staff's DCF and CAPM cost of equity models. *Id*. Additionally, Staff relied on a risk premium analysis and a review of other state commission ROE decisions to help reach a recommended cost of equity for DTE Electric. *Id*.

2. Discounted Cash Flow Model

The Discounted Cash Flow (DCF) model assesses that investors value stocks by "discounting" to the present the expected future cash flows attributed to those securities, which include dividends, a capitalization rate applied to the future cash flows and the projected market value of the securities at liquidation. (8 TR 4074.) Staff obtained the data for its DCF analysis using statistics from its proxy group and growth estimates from industry experts. Staff's DCF analysis yielded an average ROE estimate of 8.82%. (8 TR 4075.)

Staff's testimony also addressed the Company's DCF analysis and ROE estimate. (8 TR 4076-4079.) Staff disagreed with the Company's proxy group that consisted of 25 companies. (8 TR 4076.) Staff concluded that at a minimum 8 utilities in the Company's proxy group should have been excluded either due to size unreasonableness, improper affiliation and/or merger involvement. *Id.* Staff also rejected the Company's after-tax weighted average cost of capital approach (ATWACC). (8 TR 4078-4079.) The approach used the Company's standard DCF results as inputs into its market value cost of capital projection and then backed-into a ratemaking ROE using the Company's ratemaking capital structure percentages. (8 TR 4078.) Staff noted that the Company's ATWACC approach has never been adopted by a regulatory commission in a regulated electric or gas rate case proceeding. (8 TR 4079.) Staff also noted the Company's Hamada adjustment was similar to its ATWACC adjustment and was thus equally improper. (8 TR 4087.) The AG asked Company witness Vilbert in cross how many state regulatory commissions have relied on his ATWACC approach. Dr. Vilbert replied that to his knowledge none relied on it exclusively. (6 TR 2061-2062.) Therefore, Staff suggests that the ALJ and Commission reject the Company's ATWACC and Hamada adjustments.

3. Capital Asset Pricing Model

The Capital Asset Pricing (CAPM) model infers that investors are exposed to two types of risk, diversifiable (firm specific) and non-diversifiable (market) risk. (8 TR 4079.) The CAPM suggests that an investor is fully invested in a portfolio of stocks and thus eliminates firm specific risk and is only exposed to non-diversifiable or market risk. (8 TR 4079-4080.) The risk of an asset and thus the investor's required return is a function of the risk that the asset contributes to the market. This market risk is characterized by the beta coefficient. (8 TR 4080.) Therefore, to estimate a cost of equity using the CAPM, one needs a risk-free rate, an estimate of beta for the proxy group and a market return for a wide portfolio of assets. Staff used a long-term U.S. Treasury bond yield forecast for its risk-free rate and proxy group betas from Value Line. (8 TR 4081.) Staff's CAPM analysis produced ROE estimates of 8.29% and 7.89%. *Id.* Staff also performed a projected CAPM analysis using Value Line market data. The projected CAPM analysis produced a ROE estimate of 9.87%. (8 TR 4082.)

Staff also addressed the Company's CAPM analysis and ROE estimate. (8 TR 4082-4087.) Staff disagreed with the Company's analysis, in particular the Company's use of an Empirical CAPM or ECAPM method along with its ATWACC and Hamada modifications. (8 TR 4083.) Staff noted several issues with the

ECAPM approach, including the use of adjusted betas in the model. (8 TR 4083.) Staff surmised that its basic inputs into the CAPM model rendered the ECAPM adjustment unnecessary. During cross the AG asked witness Vilbert if he knew how many state regulatory commissions have adopted ECAPM. Dr. Vilbert responded that he did not know. (6 TR 2061.) Staff noted that the ECAPM was unnecessary and counter intuitive to fair and balanced ratemaking and that the Commission should reject the ECAPM approach and ROE estimates. (8 TR 4086.)

4. Risk Premium Method

The risk premium approach incorporates the spread between historical electric utility realized stock returns and historical composite utility bond yields and develops a cost of equity estimate by incorporating the historical data with current utility based data. (8 TR 4087.) Staff used a return period of 1932 through 2017 to obtain its historical market risk premium. *Id.* Staff also used a projected market risk premium of 6.47% derived from its projected CAPM analysis. (Exhibit S-3, Schedule D-5, p 8.) Staff used average yields for A-rated and BBB-rated bonds from Value Line from August through October 19, 2018. (8 TR 4088.) The risk premium model produced historical ROE estimates of 8.97% for A-rated bonds and 9.18% for BBB-rated bonds. (8 TR 4088.) The risk premium model also produced projected ROE estimates of 10.84% for A-rated utility bonds and 11.05% for BBB-rated utility bonds. (8 TR 4088.)

Staff also addressed the Company's risk premium analysis. (8 TR 4088-4089.) Staff disagreed with the Company's use of authorized ROEs as an input into the Company's risk premium analysis. (8 TR 4089.) Staff concluded that using authorized ROEs to determine a market risk premium was subjective and could produce inflated premiums. (8 TR 4088.) Staff concluded that the Company's risk premium analysis was questionable and that the Commission should give limited weight to that analysis and ROE estimate. (8 TR 4089.)

5. Other State Commissions' ROE Decisions

Staff reviewed the authorized rate of return decisions rendered by other state commissions from 2016 through September 2018. (8 TR 4089.) The average authorized ROE from those decisions was 9.77% for 2016, 9.74% for 2017 and 9.64% through September 2018. (8 TR 4089.) The ROE data was provided by the Regulatory Research Associates, which is a unit of S&P Global Market Intelligence.

6. Summary of Results and Staff's Recommendation

Method	Range	ROE Result
DCF Model		8.82%
Historical CAPM (Full Range)		8.29%
Historical CAPM (Fed-Accord)		7.89%
Projected CAPM Average		9.87%
Historical Risk Premium (A-Rated Bonds)		8.97%
Historical Risk Premium (BBB-Rated Bonds)		9.18%
Projected Risk Premium (A-Rated Bonds)		10.84%
Projected Risk Premium (BBB-Rated Bonds)		11.05%
Authorized ROEs of Electric Utilities Across U.S. (2016 – Sep. 2018)		9.72%
ROE Recommendation	**9.00% - 10.00%**	**9.80%**

Staff's recommended cost of equity range and 9.80% ROE recommendation provided DTE Electric with a favorable return on equity given the Company's solid capital structure, favorable realized rate of return over the past few years, stable business outlook as reflected in its credit ratings and its request for a risk reducing infrastructure recovery mechanism (IRM). Staff asserted that the Company's proposed IRM would collect millions in surcharge revenues for upcoming investments through December 31, 2022 that would practically eliminate any Company cash flow and liquidity risk associated with those investments. (8 TR 4091.) Thus, Staff's 9.80% ROE is generous and the Company's 10.50% ROE request is burdensomely high and unfair to ratepayers and should be rejected by the Commission. (8 TR 4091.)

7. DTE Electric's ROE Rebuttal Testimony

Dr. Vilbert sponsored the Company's proposed ROE range of 9.75% -10.75% and 10.50% ROE recommendation. (6 TR 1919.) Dr. Vilbert submitted rebuttal testimony disputing Staff and the other intervenor's ROE analyses and recommendations. The Company argued that Staff and the other intervenors analysis didn't properly consider projected interest rate hikes, didn't properly adjust for increased risk in the electric utility industry, didn't properly account for increased utility risk due to the passage of the 2017 Tax Cuts & Jobs Act (TCJA), and dismissed ROE estimates provided by the ECAPM and ATWACC approaches. (6 TR 2012 – 2016). Staff disagrees with the Company and will provide a few points of clarification to certain arguments the Company made. However, Staff selectively responding to the Company's arguments in its rebuttal testimony below should not be construed as agreement with those arguments Staff does not address. Staff continues to maintain its stated position regarding return on equity.

a. Staff's ROE recommendation properly accounts for the impact of the 2017 tax reform.

The Company argues that Staff and others have not properly accounted for the increased risk of the TCJA in their ROE recommendations. (6 TR 2024.) The Company argues that important financial ratios the rating agencies consider, like FFO/Debt, are under pressure due to the negative cash-flow impacts of tax reform. (6 TR 2025.) Staff disagrees and noted that the passage of the TCJA did not affect the Company's going-forward credit rating and that the Company's strong financial performance over the past several years places the Company's creditworthiness in a solid position. Thus, the Company's argument for increased ROE consideration due to TCJA should be dismissed by the ALJ and Commission.

b. Staff's DCF analysis properly treated dividend growth and used reasonable analyst's growth rates and services.

The Company argued that Staff's DCF analysis, in particular its use of a mid-year or ½ year convention for dividend growth in the model, unreasonably reduced Staff's ROE estimate by 10-20 basis points. In addition, the Company argued that Staff's use of traditional growth rate forecasting services, i.e., Value Line, Yahoo Finance and Zacks were flawed because of supposed analyst overlap. (8 TR 1490-1492.) The Company's arguments are meritless.

The Company argues that Staff should have used a quarterly dividend growth rate convention in its DCF analysis because dividends are paid quarterly. (8 TR 1491.) The Company is correct in that dividends are usually paid quarterly, but incorrect in surmising that dividends grow quarterly. Staff's use of the ½ growth rate convention assumes that changes in quarterly dividends occur for a proxy group at various times in the year. Thus, dividends can grow either in the first quarter or the fourth quarter in a calendar year. Thus, for a proxy group of companies, dividend growth is assumed to occur in the middle of the year, i.e. the ½ annual growth rate convention that Staff employs in its model. (9 TR 2354.) The Company's assertion that, since dividends are paid quarterly, they should also grow quarterly is unreasonable. The Company's other argument that Staff's sources for its growth rate estimates are overlapped and flawed is also meritless. Staff's forecasting services, i.e. Value Line, Yahoo Finance and Zacks are considered sound and credible sources to use for growth rate estimates. These services are used by many, if not the majority, of cost of capital analysts across the country in rate case proceedings. The Company has not provided proof or verification that the sources overlap or are redundant. Thus, the Company's arguments that the sources are overlapped is baseless and should be rejected by the ALJ and the Commission.

c. The Company's ECAPM analysis and ROE should be rejected.

The Company reiterated its insistence on the merit of the ECAPM approach, arguing that Staff failed to recognize the financial theory behind the ECAPM, provided a cherry-picked description of Dr. Morin's manual that Staff and the Company reference, and noted that the lower tax burden on capital gains was no longer relevant. (6 TR 2036-2039.) The Company's arguments fall short.

The Company surmised that Staff made little to no reference to its explanation regarding the appropriateness of using adjusted betas in the ECAPM. (6 TR 2038.) However, Dr. Vilbert explained that adjusted betas are the better estimate of a "true" beta for expected future returns in the CAPM. (6 TR 1960.) This adds credence to Staff's argument that the ECAPM is unnecessary given that Staff uses long-term Treasury bonds as its risk-free rate and uses adjusted betas, which the Company surmised is the most accurate beta to use[9]. Staff's risk-free rate in its CAPM analysis increases the starting point along the vertical axis in correspondence to the ECAPM security market line, while Staff's use of adjusted betas and the lower capital gains tax on dividends[10] increase the slope along the horizontal axis, in correspondence to the CAPM security market line. (8 TR 1499.) Thus, Staff has shown that its CAPM analysis is reasonable and appropriate without the need for an empirical adjustment. The Company's plea that its ECAPM approach and ROE estimate is more reasonable and necessary should be rejected by the ALJ and the Commission.

---

[9] The empirical study, as referenced in Dr. Vilbert's direct testimony used short-term risk-free rates as well as raw, unadjusted betas.

[10] Staff noted that capital gains tax maxes out at 15-20%.

d. ABATE's argument against Staff's recommended equity balance should be rejected.

ABATE argues that Staff's recommended equity balance of 51.0% should be rejected because Staff did not support its analysis and that Staff's recommendation was contradictory to its testimony. (7 TR 3029-3030.) ABATE's arguments are meritless.

Staff reviewed the Company's historical 2017 capital structure as noted on Company witness Slater's Exhibit A-4, Schedule D1, page 1 of 1. Staff noted that the permanent equity percentage at the end of 2017 was 50.63%. Thus, Staff surmised that a 51.0% equity layer in this case was not unreasonable. Staff reviewed witness Solomon's testimony with respect to the Company's recommended equity layer. While witness Solomon did reference TCJA as a reason for a 51% equity layer, Mr. Solomon also provided additional arguments and noted that the 51% equity layer was relatively consistent with recent actual balances. (5 TR 1047.) Staff reviewed the Company's historical balance and agreed that the 51% equity layer request was relatively consistent with its historical balance and was not moving egregiously away from the more equitable 50/50 capital structure. Therefore, ABATE's argument that Staff's equity layer recommendation was based on the impacts of the TCJA and inconsistent with its testimony is baseless and should be rejected.

8. ROE Recommendation Summary

The Commission should adopt Staff's reasonable 9.80% ROE recommendation. Staff's ROE is near the top end of Staff's 9.00% - 10.00% range, is higher than both the AG's and ABATE's recommendations[11], is roughly in line with ROEs awarded by other state commissions in 2016 through September 2018 and would not negatively impact the Company's solid credit rating and access to competitively cost debt. DTE Electric has on average over-earned its ROE the past 5 years and is therefore better aligned for a more reasonable and considerate ROE along the lines of Staff's recommendation that will benefit both the Company and its ratepayers. In addition, the Company's request for a risk-mitigating IRM also calls for a more competitive ROE along the lines of Staff's recommendation. Thus, Staff urges the Commission to adopt its fair 9.80% ROE recommendation and reject the Company's overinflated and unreasonable 10.50% ROE recommendation.

V. Net Operating Income

Reduced to its essence, Adjusted Net Operating Income (NOI) is the difference between a company's operating revenues and operating expenses for the projected test year. *In re Detroit Edison's 2010–2011 Rate Case*, MPSC Case No. U-16472, 10/20/2011 Order, p 41.

A. Staff recommends an adjusted net operating income of $829,868,000.

In its initial filing, the Company recommends an adjusted net operating income (NOI) of $750,856,000, while Staff recommends an adjusted NOI of $829,868,000. (Appendix C.) Differences between the Staff's and the Company's

[11] The AG recommended a 9.50% ROE and ABATE recommended a 9.30% ROE.

total adjusted NOI are due to Staff adjustments to various Company revenue and expense projections as detailed below.

1. Staff recommends total operating revenues of $4,786,249,000.

DTE projects that its total operating revenues will be $4.785 billion in the projected test year, which is $900,000 less than Staff's projection of $4.786 billion. (Appendix C.) Staff's adjustment is related to (Residential Income Assistance) RIA and is discussed below.

a. Staff recommends sales revenue of $3,310,110,000.

DTE projects that its total sales revenue will be $3.209 billion in the projected test year, which is $900,000 less than Staff's projection. (Appendix C.) Staff recommends the ALJ and the Commission adopt the Staff's adjustment related to RIA.

i. The Commission should accept Staff's projected RIA enrollment.

The Company has proposed adding an additional 35,000 customers to its RIA program in order to offset a system error in which eligible electric-only customers were not enrolled in the program. This brings the company's projected RIA enrollment to 70,000 customers. (7 TR 3133.) The Company's enrollment projection is overstated. Staff's projected RIA enrollment is 60,000 customers. (8 TR 4274.)

Staff witness Gottschalk testified that the Company improperly assumes that 100% of the eligible electric only customers will enroll in the RIA program when historically, that has not been the case:

> Staff does not believe it is reasonable to assume that all of the 35,000 eligible electric only customers would participate in the program. Exhibit S-18 shows the amount of eligible RIA customers and the amount actually enrolled in the program for each year for the past 5 years. This data results in an average participation rate in the RIA program of approximately 68%. If you apply that participation rate to the additional 35,000 electric only customers, that would result in an additional 23,800 estimated customers in the program. This would bring the total estimate of customers in the program to 58,800. As the Company has requested 70,000 customers for the RIA, Staff would round its estimate up to 60,000 customers. This would result in a reduction of $900,000 to present revenue. This change is not included in Staff's revenue requirement but the Commission should include it when deciding the outcomes in this case. [*Id.*]

Staff misidentified the change to present revenue as a $900,000 reduction. Staff's adjustments to RIA enrollment actually results in a $900,000 *increase* to present revenue. Staff has made this adjustment in its updated revenue requirement. No intervenor took a position on this issue. For the reasons stated above, the Commission should adopt Staff's projected RIA enrollment as it is based on historical trends in the program.

b. Staff recommends base fuel and purchase power revenue of $1,385,795,000.

The Company projected that it would receive $1.386 billion in base fuel and purchase power revenue. (Appendix C.) Staff recommends the Commission adopt the Company's projection.

c. Staff recommends other revenue and R2 of $90,345,000.

The Company projected that it would receive $90.345 million in other revenue and R2. (Appendix C.) Staff recommends the Commission adopt the Company's projection.

2. Staff recommends total operating expenses of $3,988,360,000 for the projected test year.

Staff's recommended total operating expenses of $3.988 billion is $76.189 million less than the Company's projection of $4.065 billion. (Appendix C.) Staff breaks down this $76.189 million difference, by category, and explains the difference below:

Other O&M Expense	$(32,587,000)
Depreciation and Amortization Expense	$(71,471,000)
State and Local Income Tax	$6,779,000
Federal Income Tax	$21,090,000
Total Adjustments to Operating Expenses	$(76,189,000)

Staff takes no issue with the Company's recommended fuel and purchased power of $1,385,795,000, property taxes of $275,525,000, other taxes of $52,234,000, and other utility income/deductions of $2,134,000. (Appendix C.)

a. Staff recommends Other O&M expense of $1,279,809,000.

Staff recommends Other O&M expense of $1.280 billion, which is $32.587 million less than the Company initially filed projection of $1.312 billion. (Appendix C.) Staff proposes the following adjustments to Other O&M Expense (Appendix C):

Inflation	$(12,338,000)
Injuries and Damages	$(892,000)
Incentive Compensation	$(27,083,000)
Uncollectibles	$(234,000)
Active Healthcare	$(1,733,000)
Incremental Charge Forward	$(1,168,000)
Meter Reading	$(2,147,000)
Tree Trimming	$13,007,000
Total Adjustments to Other O&M Expense	$(32,587,000)

i. Staff recommends reducing Other O&M expense by $12,338,000 for an inflation adjustment.

Staff recommends reducing other O&M expense by $12,338,000 for an inflation adjustment. Staff used inflation factors of 2.52%, 2.23% and 2.50% for 2018, 2019 and 2020, respectively. The use of these inflation factors in lieu of the Company's resulted in a downward adjustment to Operations and Maintenance expense of $12, 338,000. (8 TR 4028.)

The Company did not file rebuttal challenging this adjustment. Staff recommends the ALJ and Commission adopt Staff's Other O&M adjustment.

ii. Staff recommends reducing injuries and damages O&M expense by $892,000.

Staff recommends reducing injuries and damages O&M expense by $892,000. Both the Staff and the Company projected Injuries and Damages Expense using a five-year average. The Company added inflation to its projections whereas the Staff did not. Staff did not add inflation because doing so would be inconsistent with how projections for this expense type have been presented in the past. Not adding inflation resulted in a downward adjustment to Operations and Maintenance expense of $892,000. (8 TR 4028.)

The Company did not file rebuttal challenging this adjustment. Staff recommends the ALJ and Commission adopt Staff's injuries and damages O&M expense adjustment.

iii. Staff recommends reducing incentive compensation O&M expense by $27,083,000.

Staff supports the removal of $27,083,000, which is the portion of the Company's employee incentive compensation plan (EICP) expense that is tied to achieving financial metrics. (6 TR 1845.) The ALJ and Commission should remove the Company's $27.1 million expense offered to employees achieving financial metrics and allow the $19.3 million not related to financial objectives.

The Commission has long held that shareholders, not ratepayers, must pay for incentives related to increasing profits, and no party has given a reason for the Commission to reverse that stance. The Company's EICP has 3 parts—the annual incentive plan (AIP), rewarding employees plan (REP) and the long-term incentive plan (LTIP). (6 TR 1842, 1843.) For the AIP and REP plans, if an employee meets certain financial objectives, such as in operating earnings, cash flow and earnings per share (EPS), that employee may receive 40% of the offered bonus. *Id.* (Exhibit A-21, schedule K1.) Under the AIP and REP plans, the Company awards 60% of the bonus based on customer satisfaction, employee engagement and operating excellence, i.e. non-financial objectives. The Company pays awards under the LTIP based solely on financial metrics. (6 TR 1852.) The projected EICP expense related to financial objectives, $27,083,000, should be removed. (8 TR 4050.) The projected EICP Expense related to non-financial objectives is $19,297,000 and should be approved in rates. *Id.* The Commission has held that the incentive compensation that is tied to Company earnings and cash flow are financial considerations that primarily benefit shareholders and ratepayers should not pay for them. *In re Consumers Energy Rate Case*, MPSC Case No. U-14347, 12/22/2005 Order, p 35. (8 TR 4049.) Staff also points to the following 11 rate cases in which the Commission removed incentive compensation costs related to the achievement of financial considerations: *In re Consumers Energy Gas Rate Case,* MPSC Case No. U-14547, 11/21/2006 Order, p 47; *In re Consumers Energy Electric Rate Case,* MPSC Case No. U-15245, 6/10/2008 Order, pp 31-32; *In re Detroit Edison Electric Rate Case,* MPSC Case No. U-15244, 12/23/2008 Order, pp 37-38; *In re Consumers Energy Electric Rate Case,* MPSC Case No. U-15645, 11/2/2009 Order, p 41; *In re Wisconsin Electric Power Rate Case,* MPSC Case No. U-15981, 7/1/2010 Order, pp 46-47; *In re Detroit Edison Electric Rate Case,* MPSC Case No. U-15768, 1/11/2010 Order, pp 48-49; *In re Detroit Edison Electric Rate Case,* MPSC Case No. U-16472, 10/20/2011 Order, p 62, 60; *In re Consumers Energy Electric Rate Case,* MPSC Case No. U-17735, 11/19/2015 Order, pp 77-78; *In re Consumers Energy Electric Rate Case,* MPSC Case No. U-17990, 2/28/2017 Order, p 106; *In re DTE Electric Rate Case,* MPSC Case No.

U-18014, 1/31/2017 Order, p 85; *In re DTE Electric Rate Case,* MPSC Case No. U-18255, 4/18/2018 Order, p 49.

In DTE Electric's last electric rate case, Case No. U-18255, the Commission noted from the previous rate case that "the Company failed to support its request for incentive compensation related to financial metrics, specifically noting that the purported benefits to ratepayers that DTE Electric cites are attenuated at best, and in some cases, specious." *In re DTE Electric 2016-2017 Rate Case*, MPSC Case No. U-18014, 1/31/2017 Opinion and Order, p 85.

Staff did not introduce evidence that the Company's overall compensation was unreasonable. Rather, Staff's recommendation is based on the Commission's Order in Case No. U-14347, which found that when incentive compensation plans are tied to Company earnings and cash flow, the plans largely benefit shareholders. Applying the same reasoning, Staff aligned the cost of financial performance measures within the incentive compensation plan to the group that benefits from those financial performance measures—shareholders. Therefore, for all reasons stated above, Staff urges the Commission and ALJ to remove $27,083,000, which is the portion of the Company's EICP expense tied to achieving financial metrics.

iv. Staff recommends reducing uncollectibles O&M expense by $234,000.

Staff recommends reducing uncollectibles O&M expense by $234,000.

Staff recommends using a three-year average based on the cash basis of uncollectible accounts for 2015 through 2017. (8 TR 4028.) The cash basis method multiplies an average of actual net write-offs to a projected level of sales. As such, it is grounded in actual experience.

The Company used a three-year average of the accrual basis (balance sheet method) of uncollectible accounts for 2015 through 2017. (8 TR 4027.) The accrual basis uses the Company's annual report account 904 expense balances. This method relies on accounting estimates that involve assumptions. (7 TR 3346.) These assumptions could result in significant forecasting error.

Staff believes that the cash basis is a better approach because it mitigates this potential for forecasting error. Further, this method has been adopted by the Commission in Case No.'s U-14347, U-16191, U-16794, U-17735 and U-17990. (8 TR 4027.) Therefore, Staff recommends the ALJ and Commission adopt Staff's methodology and adjustment.

v. Staff recommends reducing active healthcare O&M expense by $1,733,000.

Staff recommends reducing active healthcare O&M expense by $1,733,000.

The Company received an active healthcare refund of $9.471 million in March of 2018, a portion of which represented overcharges that were recovered in prior rates. The refund was not included in the Company's projections. Staff recommends that the Commission require the Company to book a regulatory liability for the $5.2 million and to credit that amount back to ratepayers over a three-year period beginning in May of 2019. (8 TR 4029-4030.)

The Company did not file rebuttal challenging this adjustment. Staff recommends the ALJ and Commission adopt this adjustment.

vi. Staff recommends reducing incremental charge forward O&M expense by $1,168,000.

Staff recommends reducing incremental charge forward O&M expense by $1,168,000. Staff witness Ozar recommended that Charging Forward infrastructure operations and maintenance (O&M) expenses be deferred and recovered through regulatory asset accounting. (8 TR 3410.) Based on his recommendations, Staff reduced corresponding Charging Forward O&M expenditures.

vii. Staff recommends reducing meter reading O&M expense by $2,147,000.

Staff recommends reducing meter reading O&M expense by $2,147,000. The ALJ and the Commission should adopt Staff's projected meter-reading expense of $1.483, which is a $2,147,000 reduction to the Company's projected $3,630,000 test-year expense. (Exhibit A-13, C5.7, line 4.) The Company's projection for meter-reading expense does not include the projected benefits of the AMI program, as the Company's projection does not include the reduction in the number of meter readers the Company utilizes to manually read its meters. The projected meter reading expenses of $3,630,000 is based on historical spending, at a time when the Company employed substantially more meter readers than it does today. It is imprudent to base test-year meter-reading costs on the 2017 historical year. The Company has not incorporated any of the operational benefits of the AMI program—specifically the substantially lower number of meter readers—into its meter reading projections. In its historical year, the Company had 58 meter-readers, while in its test year the Company projects that it will only have 24. (Exhibit S-12.3, p 13.) Therefore, Staff developed a meter-reading cost by applying the cost per meter reader in the historical period to the number of meter readers in the test year.

Company rebuttal witness Johnson states that other expenses are included in the meter reading expenses line item including billing operations, metering operations, consecutive estimates team, and special reading expenses. (7 TR 3139.)

Staff calculation of meter reading expense is correct. The Company has named other expenses that have fallen into the category of meter reading expenses but gives no information about the costs associated with each of the other categories. It is Staff's assumption that the majority of the expenses in a category called meter reading expenses would be actual meter reading. The Company has not provided enough information about the other expenses in the meter reading category to justify not including the savings that the AMI program has had on this category. For this reason, the ALJ and Commission should adopt Staff's proposed meter reading expense of $1.483 million for the test year.

viii. Staff recommends increasing tree trimming O&M expense by $13,007,000.

Staff recommends increasing tree trimming O&M expense by $13,007,000. The Company is proposing a tree trimming surge, an increase in tree trimming over seven years to achieve a five-year tree trim cycle and eliminate the backlog of miles yet to be trimmed as part of the Enhanced Tree Trimming Program. (3 TR 210.) The surge would take place from 2019 until the end of 2025 and would cost $410 million above normal tree-trimming costs. The Company plans to place the surge expenses into a regulatory asset and amortize the costs over 14 years. (8 TR 4127.) The net present value (NPV) of the Tree Trim surge as proposed is $46.1 million. (Exhibit A-22, Schedule L1.)

Staff supports most aspects of the surge. Staff supports the goal of achieving a five-year tree trimming cycle for distribution circuits and the Company's current three-year cycle for sub-transmission circuits. Staff also agrees there is a backlog of overgrown vegetation that must be addressed for the Company to achieve a five-year cycle and removing this backlog will require additional funding. (8 TR 4128.)

However, Staff does not believe amortizing the costs is in the best financial interest of ratepayers. Since the Company plans to place the surge expenses into a regulatory asset and amortize the costs over 14 years, the actual cost to ratepayers could be over $600 million due to the return on deferral, although this cost may be less if the Company securitizes the costs. (8 TR 4127.) The NPV of the surge without regulatory asset treatment is $55.4 million compared to $46.1 million as proposed (8 TR 4128), so in the long run, ratepayers would be better off paying the full O&M costs every year instead of deferring them.

Placing the surge costs into a regulatory asset and amortizing them will burden future ratepayers with costs that are more appropriately O&M expense that should be paid as the costs are incurred. (8 TR 4128.) Amortizing the costs of the surge over 14 years means that ratepayers will be paying for a year of surge-related trimming for 14 years thereafter. A circuit trimmed as part of the surge may be trimmed two more times with the new five-year cycle and ratepayers will still not have paid off the surge-related trimming of the circuit. In this manner, DTE Electric is proposing tree trimming be treated similar to a capital expenditure when traditionally tree trimming is an O&M expense. (8 TR 4129.)

Staff wants to proceed with caution as DTE Electric ramps up spending to achieve a five-year cycle. Staff proposes that for years following the test year, the Company could request increases in spending on tree trimming until the backlog is eliminated and the five-year cycle is achieved, then drop the O&M amount to its forecasted amount in Exhibit A-22, Schedule L1. This would allow tree trim O&M expense embedded in rates to increase gradually and make the surge more affordable in the short run. (8 TR 4129.) Staff's Exhibit S-10.5 shows how Staff's proposed approach might work, and that the proposal could provide the Company with the revenue the surge requires. (Exhibit S-10.5.) Staff's example in Exhibit S-10.5 should not be taken as pre-approval of future tree trim O&M amounts. Staff anticipates that the Company's proposed expenses will be different from Staff's, as the Company will be able to incorporate workforce constraints, program efficiencies, field conditions, and other pertinent factors into its forecasts. (8 TR 4131.)

In addition, the proposed O&M expenses should be justified and shown to be reasonable and prudent in any rate cases that are filed in the 2019 – 2020s time period. As part of this justification, the Company should show, that the most recent Commission-approved tree trim O&M amounts are providing benefits to both customers and the Company. Progress toward shortening the trim cycle and improving reliability should be documented and provided in each rate case. *Id.*

For the test year, Staff recommends the Commission not approve the regulatory asset for the Tree Trim surge, which means disallowing the $7,053,000 revenue requirement associated with the surge. At the same time, the Commission should increase Tree Trim Expense during the test year from $95,092,000 (the Company's request) to $108,099,000, a 28.3% increase over 2017 actual tree trim spending. (8 TR 4129; Exhibit A-13, Schedule C5.6.) This should give the Company a good start on transitioning to a five-year cycle and be affordable for ratepayers.

In her rebuttal testimony, Company witness Heather D. Rivard says that DTE Electric believes the surge program should be approved for three reasons: 1) the Company's surge will allow the Company to more quickly reduce the tree trim backlog miles compared to Staff's proposal; 2) the Company's surge plan provides smaller near-term rate increases compared to Staff's proposal and allows the Company to align rate increases with future customer benefits; and 3) approval of the Company's proposed surge plan will allow for funding certainty that will help the Company enter into long-term contracts with tree trimming vendors. (3 TR 248-249.)

In response, Staff acknowledges that its surge proposal would take longer to complete than the Company's and would cause a larger near-term rate increase.

However, Staff's proposal has advantages over the Company's plan—it is cheaper overall, and ratepayers will not be paying for tree trimming 14 years after the fact. These advantages also outweigh any alignment between rate increases and future customer benefits that occurs with the Company's surge. Staff would prefer to save customers money and have them pay the bill as quickly as possible rather than have them pay more and pay the bill over nearly 20 years. (Exhibit A-22, Schedule L1.) Staff would remind the Commission that this tree trimming is not associated with any capital expenditures. The trimming will have to be performed again in five years, and no depreciable assets or equipment will be installed. Simply put, there are no compelling reasons to treat the expenses for this trimming as de-facto capital expenditures.

Staff is skeptical of the claim that funding certainty will help the Company enter into long-term contracts with tree trimming vendors. The Company's position here is borderline speculative—DTE Electric provides no letter, email or document from a reputable tree trimming vendor that says a long-term contract is not possible without long-term, Commission-approved funding. The Commissioners should not let this unsupported claim sway them into approving regulatory asset treatment of the Tree Trim surge. However, if the Commission agrees with Staff's proposal but believes it must provide reassurance to tree trimming vendors in a public document, the Commission could state, in its final Order in this case, its support of DTE Electric moving to a five-year tree trimming cycle and its willingness to approve the O&M funding necessary to achieve that end.

Company Witness Rivard says that if the Commission accepts the Staff's recommendation to expense the tree trim costs, the Company requests $137.5 million in O&M for the May 1, 2019 – April 30, 2020 test year, which equates to $119.6 million for the 2019 calendar year. The Company believes this would be a reasonable compromise between the Staff and Company surge proposals. (3 TR 249.) Staff disagrees. The Company is currently recovering $83.749 million annually in tree trimming expense. *In re DTE Electric Co*, MPSC Case No. U-18255, 04/18/2018 Order, p 44. A jump up to $137.5 million would be a 64.2% increase—far too large. Staff's $108,099,000 for the test year was chosen specifically to avoid a sharp increase in rates. As stated earlier, Staff's proposal would allow tree trim O&M expense embedded in rates to increase gradually and make the surge more affordable in the short term. (8 TR 4129.) Staff's proposal aims to minimize both short-term costs (by ramping up costs gradually) and long-term costs (by eliminating the return on deferral associated with amortization, regulatory asset treatment and securitization). The Commission should adopt the Staff's recommendations on tree trimming.

b. Staff recommends depreciation and amortization expense of $877,515,000.

In its initial filing, DTE projected that its depreciation and amortization expense would be $948.986 million. Staff decreased this projection by $71.471 million for a depreciation and amortization expense of $877.515 million. (Appendix C.) Staff adjusted depreciation and amortization expense for two reasons. The first difference stems from Staff's capital expenditure adjustments; fewer capital expenditures reduced the total being depreciated and, thus, the depreciation expense. (See Section III.A.1.b. and Appendix E.) Capital expenditure adjustments reduced depreciation expense by $6,233,000. (Appendix C, line 14). Second, Staff adjusted the depreciation rates used to calculate depreciation in a manner consistent with the new approved rates in the Commission's December 6th Order in MPSC Case No. U-18150. The company projected depreciation expense based upon the rates it proposed in its initial filing in *In re DTE Electric Co. for approval of depreciation rates,* MPSC Case No. U-18150. (7 TR 3306.) On December 6th that case was concluded with a final Order. Therefore, Staff adjusted depreciation rates to reflect the new approved rates, which reduced depreciation expense by $65,238,000. (Appendix C, line 13 and Exhibit S-22.) Staff recommends that the ALJ and the Commission adopt Staff's adjustment to incorporate the impacts of the new depreciation rates ordered in *In re DTE Electric,* MPSC Case No. U-18150, 12/06/2018 Opinion & Order, pp 2-3. Staff's calculation is supported by the Company's discovery response which recalculates depreciation expense using new approved depreciation rates from MPSC Case No. U-18150. Exhibit S-22.

c. Staff recommends state and local income tax expense of $49,322,000.

Staff recommends state and local income tax expense of $49.322 million, which is $6.779 million more than the Company's projection of $42.543 million in its initial filing. (Appendix C.) The difference between Staff's and the Company's state and local income tax expense is the result of various Staff adjustments to the Company's projected revenues and expenses.

d. Staff recommends federal income tax expense of $66,026,000.

Staff recommends federal income tax (FIT) expense of $66.026 million, which is $21.090 million more than the Company's projection of $44.936 million in its initial filing. (Appendix C.) Again, Staff's adjustments to the Company's projected revenues and expenses are responsible for the difference.

e. Staff makes several Energy Waste Reduction recommendations.

The Commission directed the Company to support its forecasting methodology and calculations and more specifically, provide detail on how it addressed the impacts of energy waste reduction (EWR) programs on the future load forecasts. *In re Consumers Energy Company's Electric Rate Case,* MPSC Case No. U-18322, 03/29/2018 Order, p 50. In the same Order, the Commission also directed Staff to engage with stakeholders on the topic of EWR and its effects on sales forecasting. Staff met with DTE Electric prior to the filing of this rate case to learn more about these effects. As testified by Staff witness Karen Gould, Staff is aware there are multiple excepted ways to account for the effects of utility funded EWR programs in forecasting. (8 TR 4214-4215.) Through this meeting and additional findings via audit requests, Staff believes, at this time, the forecast methodology used by the Company seems reasonable. Additionally, Staff anticipates future active conversations with Michigan utilities regarding EWR effects on sales forecasting within the EWR Collaborative.

Staff maintains that the Company's EWR low income program can have a more lasting impact for its customers by aligning itself with the Company's Revenue Management and Protection section and targeting those customers who struggle with bill payment, as well as enrolling them in the Low Income Self Sufficiency Plan, as testified by witness Brad Banks. (8 TR 4205.) By addressing the quality of low income housing stock through weatherization and mitigation measures, the EWR program can positively affect both high energy consumption and the health and safety issues which occur in low income housing stock. The Company also has an opportunity to lead the state in standardizing contractor weatherization certification.

B. Staff recommends a total allowance for funds used during construction (AFUDC) operating income adjustment of $34,896,000.

DTE included $32,973,000 in total as an AFUDC operating income adjustment in its initial filing. Staff recommends increasing AFUDC operating income adjustment by $1,923,000, to $34,896,000. (9 TR 4058.) The Company agrees with Staff's assessment that the Company's AFUDC credit on the income statement is equal to the AFUDC included in Construction Work in Progress (CWIP) as a cost of construction. (7 TR 3350.) Further, the Company confirms that amount is $32,973,000. (Exhibit S-9.0.) Additionally, the Company cites that CWIP is allowed for ratemaking purposes via the Commission's May 10, 1976 Order in Case No. U-4771. 7TR 3325. Staff is not in disagreement with the Company's inclusion of CWIP for ratemaking purposes and would note that by AFUDC being in CWIP, it too, is part of CWIP allowed for ratemaking purposes. However, Staff does disagree with the inclusion of AFUDC in CWIP without an offsetting adjustment to operating income. Without an offsetting adjustment to operating income the company would be earning a return of $2,594,975 on its financing costs (AFUDC) (Exhibit S-9.0) and thus burden the ratepayer with providing the company recovery of its financing costs prior to those costs being closed to plant in service.

Company witness Mr. Stanczak, Vice President of Regulatory Affairs, under cross examination explained that AFUDC stands for allowance for funds used during construction, and it's a regulatory ratemaking methodology that allows utilities to book a return on certain large capital projects while they're under construction. (3 TR 184.) Mr. Stanczak goes on to describe DTE's position in this case regarding AFUDC stating "and then there's what's called an AFUDC offset reverses the income impact of AFUDC, so the idea is that we don't get to recover return twice on these projects." *Id.* This explanation by Mr. Stanczak's mirrors Staff's reason for its adjustment, "[w]ithout this additional offset the Company will be allowed to earn a return on its AFUDC. Thus, to offset the impact of the

Company earning a return on its return (AFUDC) Staff made and adjustment to increase the Company's AFUDC operating income adjustment." (9TR 4058.)

Both DTE witness Mr. Stanczak and Staff's reasoning regarding the AFUDC offset comport with the Commission March 14, 1980 Order in Case U-5281, where, on pages 75-76, the Commission states, "AFUDC capitalization will continue to be approved by this Commission but such AFUDC capitalization shall not be compounded. **For ratemaking purposes, an AFUDC offset to CWIP allowed will continue to be determined as an adjustment to net operating income** except that no AFUDC offset sill be applied to CWIP relating to pollution control facilities on fossil fueled power plants." (Emphasis Added).

Company witness Ms. Uzenski, in rebuttal, opposes Staff's adjustment noting that the Company's method for determining the AFUDC credit for rate-making purposes is consistent with the order and practice used in prior rate cases. (7 TR 3351.) She also notes that it would be inconsistent to allow a return on AFUDC once it becomes part of the plant but not while it is in CWIP. *Id.* Staff argues that it would be inconsistent to allow the Company a return on its return, via inclusion of AFUDC in CWIP with no offset, and yet offset the CWIP that the AFUDC is contingent upon, until placed in plant in service and put into rates. Company witness Stanczak, during cross examination was asked if in the recent past, has it been DTE's position that ratepayers would not pay for project financing until that project was in service. He responded that he would agree that's the general ratemaking methodology that's been employed for the Company's ratemaking. (3 TR 185.)

Further, when asked during cross "[s]o, essentially, then, your position that you're stating is that investors would finance construction of capital costs while ratepayers would pay later once there was a Commission order reflecting those project costs in rate base, is that correct?" Mr. Stanczak provided "[w]ell, I just want to be clear that investors would supply the funds, but, in the end, our customers would pay for the carrying costs during the construction period, but it would happen after, the actual cash would be received from customers after the project is put in service and put into rates." *Id.* FERC even explains this as "[i]ncluding CWIP in rate base permits the utility to recover its financing costs as they are incurred, while AFUDC reflects those same financing costs with recovery deferred until the plant goes into service. F.E.R.C. Docket No. ER09-1158-000, Delmarva Power & Light Company, Order Denying Formal Challenge, p 18 (2017).

Again, Staff's reasoning for its adjustment mirrors that of Company witness Mr. Stanczak as Staff's adjustment to increase the Company's AFUDC operating income adjustment by $1,923,000 offsets the impact of AFUDC being included in CWIP until such time as those costs are closed to plant in service and put into rates.

If the Commission does not adopt Staff's adjustment, it will be approving that AFUDC included in CWIP would not be revenue requirement neutral while the underlying projects in CWIP that the AFUDC is contingent upon is revenue requirement neutral. Therefore, Staff recommends the Commission adopt its adjustment to increase the Company's AFUDC operating income adjustment by $1,923,000 in order to offset recovery of these carrying costs until such time they are cleared from CWIP to plant in service and put into rates which is consistent with traditional ratemaking methodology regarding AFUDC, in such, that rate payers aren't burdened with paying for projects or financing costs related to those projects until such time as they are closed to plant in service and put into rates.

C. Staff recommends Other Operating Income Adjustment of ($2,917,000).

The Company projected Other Operating Income reduction of $2,917,000. (Appendix C, column q.) Staff recommends the ALJ and Commission adopt the Company's projection.

VI. Staff recommends several modifications to the Company's proposed Inflow/Outflow Distributed Generation tariff.

A. Staff supports the Inflow/Outflow pricing model for the Company's Distributed Generation (DG) program.

Pursuant to the passage of Public Acts 341 and 342, and the Commission order in *In the matter, on the Commission's own motion, to implement the provisions of Sections 173 and 183(1) of 2016 PA 342 and Section 6a(14) of 2016 PA 341*, MPSC Case No. U-18383, 4/18/2018 Order, the Company filed its proposed distributed generation (DG) tariff in this case.

The Company's Exhibit A-16, Schedule F10 contains tariff sheets providing its proposed DG program. Additionally, as described by its witness Philip Dennis, the Company also filed a modified version of the Distributed Generation

Inflow/Outflow tariff attached to the Commission's April 18, 2018 Order in MPSC Case No. U-18383. (8 TR 3876.) Although the Company supported the Inflow/Outflow pricing model as the basis for its DG program, the Company is not requesting approval of the tariff provided in Exhibit A-16, Schedule F10.1 but included it in this case for the purpose of complying with the Commission's April 18 Order directing utilities to file the Inflow/Outflow tariff attached to that order in any rate case filed after June 1, 2018. The Company is requesting approval of its own DG tariff presented in Exhibit A-16, Schedule F10, which modifies the tariff attached to the Commission's Order in MPSC Case No. U-18383.

The Company's witness Camilo Serna presented direct and rebuttal testimony in support of the Company's filed DG tariff. In his direct testimony, Mr. Serna presented a brief statutory and regulatory background behind the filing of this new tariff, and then presented his support for the tariff, broken into three main subject areas: Inflow, Outflow and System Access Charge (SAC). (8 TR 3587-3588; 3597; 3598; 3601.)

Mr. Serna discusses the cost of service principles that he claims underpin his recommendations in support of the Company's proposed new DG tariff. He explained that the existing "net metering" construct used in Michigan, pursuant to Act 295 which has since been superseded by Act 342, was based on a monthly netting of the total inflows and total outflows attributed to the particular participating customer. (8 TR 3593.) Mr. Serna went on to explain that neither true net metering, nor modified net metering adhere to equitable cost of service principles. Mr. Serna asserted that net metering, as it existed in the old (Act 295) paradigm, resulted in significant cost shifting to the remaining members of the rate class who were not net metering participants. (8 TR 3594). Now, given that there exists advanced metering technology beyond that which existed under the old paradigm, the Company proposes a DG tariff which consists of an inflow rate applied to total inflow, an outflow rate credited to the DG customers' outflows and based on the locational marginal price (LMP), and a System Access Contribution (SAC) to account for "24/7 optionality all distributed generation customers maintain to use the full capability of the electric system." (8 TR 3596.)

Staff fully supports an inflow/outflow tariff as the basis for a cost-of-service based DG billing method but differs with the Company on some key issues. Staff asserts that an inflow/outflow tariff is consistent with Staff's DG tariff study admitted in this proceeding as Exhibit MEC-162, the Commission's April 18, 2018 order in MPSC Case No. U-18383, and Staff witness Robert Ozar's testimony in this case. However, Staff maintains several fundamental disagreements with the Company's Inflow/Outflow proposal and the reasoning behind it: (a) compensation for power outflows; (b) DTE's proposed System Access Charge (discussed below); and (c) several provisions implementing the tariff.

1. Staff recommends the inflow rate be the underlying full-service rate of the DG customer.

The Company proposes that inflow rate charged to the distributed generation customer be the full-service retail rate for the rate schedule for that particular customer's rate class. (8 TR 3597.) Staff supports this part of the Company's DG proposal.

2. Staff does not recommend approval of the Company's proposed System Access Contribution (SAC).

Staff recommends that the ALJ and Commission reject the Company's proposed SAC charge. Mr. Serna explained that costs linked to the 24/7 optionality that all customers enjoy was traditionally recovered volumetrically. However, given that distributed generation customers receive lower inflow from the Company's distribution system, these utility infrastructure costs increasingly remain unrecovered and are shifted onto non-participating customers. Therefore, the SAC charge was developed to account for the DG customers "full electric system use optionality." (8 TR 3599-3600). Staff agrees that customers should pay for the distribution infrastructure they use but disagrees that this amount is correctly calculated by including the SAC as proposed.

The Company based the calculation of the SAC on what it called "universal consumption based distribution charges," but is actually an imputation of what the customer would have used absent DG installation. (8 TR 3875; 8 TR 4233.) This would result in DG customers paying distribution charges for electricity generated and used behind the meter as if it were delivered by the Company, which it is not. As stated by Staff witness Krause:

> Usage can increase or decrease for any number of reasons such as change in household size, EWR, or the addition of a new end use, like an electric vehicle. It is not appropriate to impute usage that would have been had not the customer installed DG, just as it would be

> inappropriate for any other customer who reduces their usage for any other reason. The measured amount of total inflow, whether by demand or energy, is the appropriate measure for determining distribution usage not just for DG customers, but for all customers. [8 TR 4234.]

In addition to the flaws in the methodology, the Company proposes to charge only DG customers based on this method. To treat DG customers differently would effectively treat them as a separate class, which is inappropriate, as their usage is within normal variation of the residential class. (8 TR 4233-4234). The Company claims that DG customers' export of power creates additional costs. (8 TR 3668-3669.) The distribution charge, however, is paid by those to whom power is delivered and should remain so. (8 TR 4235.) The Company's proposed SAC is not based on these supposed additional costs, but imputed usage, and should be rejected for that reason alone.

The SAC is unreasonable for several other reasons. The SAC also acts as a distribution standby charge, a fact effectively admitted to by the Company. (8 TR 4238; 8 TR 3897-3898.) As noted by Staff witness Krause, the SAC acts as an infinite demand ratchet, as it does not reduce with lowered usage of the system over some period of time to reflect lower use of the system. (TR 4234.) This is inappropriate and inconsistent with the manner in which other customers are charged. The SAC also sends the incorrect price signals for incentivizing appropriate customer behavior. (8 TR 4240.) As noted by Staff witness Krause:

> Encouraging DG customers to use their generation behind the meter would be a good thing because reducing exports to the system would reduce the utilities need to deal with backflow or surplus generation. However, if all DG customers were to increase their on-site usage, the

> SAC would be recalculated at a higher number in the next rate case. Conversely, if all DG customers were to export all of their generation, the SAC would go to zero. The direction the SAC changes with customer behavior therefore seems contrary to the behavior that you would actually want the customer to exhibit. [*Id.*]

All other parties that addressed the proposed SAC opposed it. Soulardarity witness Koeppel opposed the SAC for low income customers. (5 TR 1574, 1581.) MiEIBC witness Sherman said the SAC would be an obstacle to solar adoption. (8 TR 3530.) MEC/NRDC/SC (MEC) witness Jester opposed the SAC. (6 TR 2208.) MEC witness Rabago also opposed the SAC. (6 TR 2497-2511.) ELPC/EC/SIA/VS (ELPC) witness Kenworthy opposed the SAC. (6 TR 2322, 2336, 2346.) ELPC witness Lucas also opposed the SAC. (6 TR 2412.) While Staff does not agree with all the reasons these parties used to oppose the SAC, Staff does nonetheless agree with the outcome that the SAC be rejected.

In rebuttal the Company disagreed with Staff's use of hypothetical extreme customers, mostly attacking them because they don't exist. (8 TR 3895-3896.) Staff witness Krause acknowledged the hypothetical customers don't exist in direct testimony (8 TR 4236), so the Company's arguments amount to setting up a straw man and then knocking it down. What the Company failed to show is that adding the SAC to the extreme hypothetical customers distribution charges does not overcharge them for distribution. In addition to being unreasonable in theory, the results across the entire potential spectrum of DG customers and their potential behaviors further shows how unreasonable the SAC is.

For the reasons given above, the Company's proposed SAC should be rejected as unreasonable.

3. Staff recommends outflow compensation be determined by PSCR less transmission costs.

Mr. Serna asserted that the outflow of electricity from the DG customer onto the Company's system does not reduce the cost of the Company's distribution infrastructure nor the Company's costs related to generation capacity required to serve customer load when their generator is not producing. (8 TR 3601). Mr. Serna explained that neither of these costs vary with volumetric consumption. *Id.* Thus, the costs that are offset are that of fuel and purchased power components of the energy costs for those DG customers. The Company proposes that the average locational marginal price (LMP) adequately represents these costs. *Id.*

In his support for utilizing the LMP as the rate to compensate DG customer outflow, Mr. Serna argued that the use of power supply, less transmission cost is inferior to the LMP method because power supply consists of two principal components: fuel and purchased power, and capacity. (8 TR 3602.) However, given the unpredictability of DG customer outflow, no capacity requirement of the Company is offset by the DG customer. *Id.* Therefore, the remaining portion of power supply, the fuel and purchased power component, is effectively represented by the LMP. *Id.*

First, the Company proposes to compensate *all* power outflow at a rate equivalent to the monthly average real time LMP. The Company's witness Serna provided the rationale for its LMP based compensation proposal with which Staff witness Ozar took issue. In addition to its technical support for an LMP based compensation formula, the Company claims that the Commission's hands are tied, so to speak, with respect to legally available options for outflow compensation. The Company asserts that Section 177(4) prescribes the only available outflow compensation formulas, yet the Company's own proposal conflicts with its interpretation of the language of that provision. The Company's position that all power outflow be compensated at the LMP violates the plain language of the provision which deals with the compensation for *excess* power generated beyond inflow. Further, of the two compensation methods for excess outflow provided in Section 177(4), although Staff's recommended compensation formula superficially appears to coincide with option (b) under PA 341 Section 177(4), it is critical to note that Section 177(4) only applies such compensation formula to excess power outflows that are carried forward to future billing periods, and that the balance of power outflows are netted within the billing period on an energy basis (i.e. at the full retail rate). This issue will be addressed subsequently.

The Company presents a rather myopic view in its reasoning and justification for focusing on LMP as the preferred outflow compensation method. In contrast, Staff maintains that DG customers, in the aggregate, can demonstrate substantial future capacity value or capacity offset. As such, it is reasonable and encouraged for the Company to undertake a power outflow capacity study upon implementation of the Inflow/Outflow tariff. Thus, as explained by Mr. Ozar, Staff's position in this case is that until such data from a capacity study is available and evaluated, utilizing power supply less transmission is the preferred compensation method because it does not presuppose zero capacity value of DG customers in the future and is simple and understandable to customers, and avoids the primary subsidy related to true net metering which is the inclusion of the distribution charge in outflow compensation. (8 TR 3433.)

a. DTE's proposed tariff conflicts with its interpretation of Section 177(4).

Staff witness Ozar points out the inherent conflict in the Company's position that the Commission is bound by Section 177(4) in setting outflow compensation. He states:

> [i]f DTE's interpretation was accepted, then necessarily its own request to implement and Inflow/Outflow billing mechanism would conflict with Section 177(4), since the statutory provision provides compensation at the full retail rate for power outflows up to the level of power inflows during the billing month, whereas DTE is requesting to compensate all power outflows during a billing month at the monthly-average real-time LMP. [8 TR 3427.]

Company witness Serna referenced Section 177(4) in his direct testimony as a statute that is "highly relevant and applicable" and which "clearly define[s] certain implementation boundaries and requirements of a new tariff." (8 TR 3658.) Further, after quoting the outflow compensation portions of the statute, Mr. Serna states that "these statutory provisions preclude compensating distributed generation customers for anything other than the statutorily predetermined value of their generation." (8 TR 3659.) Next, Mr. Serna explained that the Company proposes the outflow compensation rate be the monthly average real-time LMP. (8 TR 3672.) Mr. Serna does not assert that the proposed outflow rate is applicable only to the "excess kilowatt hours generated" referred to in section 177(4). Instead, the Company's position is that all power outflow would be credited at the LMP rate. Yet at the same time, Mr. Serna asserts that the Section 177(4) prescribes the compensation rate, and therefore excludes any other compensation methodology. However, the statute itself is referring to excess outflow, not total outflow. Section 177(4) states:

> If the *quantity of electricity generated* and delivered to the utility distribution system by an eligible electric generator during a billing period *exceeds the quantity of electricity supplied* from the electric utility or alternative electric supplier during the billing period, the eligible *customer shall be credited* by their supplier of electric generation service *for the excess* kilowatt hours generated during the billing period. MCL. 460.1177(4). (Emphasis added).

The two compensation methods provided by the statute, either the LMP or the utility's power supply component excluding transmission charges, are to compensate for the excess electricity generated described in the quoted statutory provision above. However, the Company's position, through the testimony of Mr. Serna is that: 1) Section 177(4) prescribes the only two methods available for compensating outflow; and 2) these two methods apply to all outflow, not outflow exceeding inflow—the excess kilowatt hours generated.

The Commission dealt with this issue in MPSC Case No. U-18383. In its April 18, 2018 Order in that case, the Commission explained that it disagreed with DTE Electric's argument that Staff's Inflow/Outflow billing mechanism conflicted with Section 177(4) and (5). MPSC Case No. U -18383, April 18, 2018 Order, p 13. The Company argued that Section 177(4) prescribed the compensation for all outflow. *Id.* However, the Commission explained that Section 177(4) essentially defines modified net-metering and establishes a netting system where power outflow up to the level of power inflow during the current billing period is offset on a net energy basis and is equal to the full retail rate which includes power supply *and* distribution charges. *Id.* Any outflow beyond the inflow from the utility, i.e. the excess, is credited/monetized using either the LMP or power supply less transmission. *Id.* The Commission also explained that DTE Electric erroneously interpreted Section 177(4) by arguing that DG credits cannot be used to reduce distribution or transmission charges. (MPSC Case No. U -18383, April 18, 2018 Order, p 14). The Commission pointed out that Section 177(4) expressly calls for the credit to be applied to the following month's bill up to the level of that bill's total power supply charges, which do include transmission costs. *Id.* Therefore, the limitation against applying credits to transmission and distribution charges applies to the modified net metering formula for the portion of outflow that exceeds inflow, and the crediting limitation is only applicable for excess outflow credits carried forward to future billing periods. *Id.* The Commission summarized its explanation dispelling any notion of conflict between Section 177(4) and the proposed Inflow/Outflow tariff, stating:

> Section 177 applies only to modified net metering that continues to exist under the grandfathering provision in Act 342, Section 183 or under the new DG program (with an added charge to recover the COS). Section 177 does not apply to any DG billing method, such as the Inflow/Outflow billing mechanism, that implements a COS based tariff under Act 341, Section 6a(14). Instead, under Inflow/Outflow, a rate (full retail) is assigned to the energy supplied to the customer (the inflow), and a rate is assigned to the energy supplied to the grid by the customer (the outflow). [April 18 Order, p 15.]

Furthermore, Michigan Courts have repeatedly stated that effect must be given "to every word, phrase and clause and avoid an interpretation that would render any part of the statute surplusage or nugatory." *People v Pinkney*, 501 Mich 259, 282 (2018). The Company's interpretation fails to meet the requirements of this canon of statutory interpretation. Staff witness Ozar provided clarity, from a technical vantage point based on his extensive experience with energy issues, on the meaning of the terms in Section 177(4):

> Q. What is the essential purpose of Act 342 Section 177(4)?
>
> A. Section 177(4) specifies the legally-available compensation rates for "*excess kilowatt hours*" under the modified NEM billing method (a variant of *net energy billing*). The statutory provision also contains other essential metering/billing requirements associated with modified NEM credits.
>
> Q. Is "excess kilowatt hours" as defined by Section 177(4) the equivalent of total power outflows during a billing period?
>
> A. No. Section 177(4) divides the total power outflows (power physically injected into the utility distribution grid) into two portions. The quantity "excess kilowatt hours" is the residual portion remaining after power outflows are netted against power inflows during the billing period.
>
> Q. Please explain.
>
> A. Section 177(4) states: "*If the quantity of electricity generated and delivered to the utility distribution system by an eligible electric generator during a billing period exceeds the quantity of electricity supplied from the electric utility … during the billing period, the eligible customer shall be credited … for the excess kilowatt hours generated during the billing period.*"
>
> Q. How should the statutory language be understood?
>
> A. The true meaning of the term "excess kilowatt hours" in Section 177(4) is easily misunderstood. However, the statutory terminology can be simplified to extract the essential meaning. The term: "*electricity generated and delivered to the utility distribution system*" is

the essential meaning of 'power outflow'. This value can be independently measured by a smart-meter capable of measuring bidirectional power flows. Similarly, the term: "*electricity supplied from the electric utility*" is the essential meaning of 'power inflow'. It also can be independently measured by a smart-meter and integrated over a billing period. Thus, an equivalent reading of the statute is: "If the *power outflows* of an eligible electric generator during a billing period exceed the *power inflows* during a billing period, the eligible customer shall be credited for the *excess kilowatt hours* generated during a billing period."

Q. In other words, the term "excess kilowatt hours" is a net quantity?

A. Yes. It is a net quantity, i.e. a residual, mathematically equal to the excess of (power outflows minus power inflows) during a billing period. The term "*excess kilowatt hours*" is equivalent to the term "*excess power outflows*".

Q. Please explain how Section 177(4) translates into compensation for power outflows.

A. The action of calculating the residual power outflow (positive difference between power outflows and inflows during a billing period), inherently creates two distinct compensation methods for power outflows. Power outflows are netted against power inflows (up to the level of total power inflows during the billing period) <u>on an energy basis</u>, and thus effectively at the full retail rate). To the extent outflows exceed inflows during the billing period, such residual portion of power outflows (i.e. excess kilowatt hours) are carried over to the next billing period, where they are credited to the customer's bill using one of two alternate compensation formulas specified by statute. [8 TR 3424-3425.]

In contrast, the Company makes its case by narrowly focusing on the concluding sentence of Section 177 (4): "*The credit per kilowatt hour for kilowatt hours delivered into the utility's distribution system shall be either of the following: (a) The monthly average real-time locational marginal price…(b) The electric utility's or alternate electric supplier's power supply component, excluding transmission charges…*" [MCL 460.1177(4).] Only by ignoring the definitions set forth in the opening sentence of Section 177(4) is the Company able to interpret the phrase "*for kilowatt hours delivered into the utility's distribution system*" as universally applying to any or all power outflows. A universal application of the excess outflow compensation provision to all outflow renders meaningless the preceding language in Section 177(4) that defines which power outflows qualify for credits that can be carried over into future billing periods. This error in interpretation is evident in Mr. Serna's rebuttal testimony where he states:

> I believe Mr. Ozar is mischaracterizing Section 177(4) because the credits described in 177(4) (a) and (b) only apply to excess generation that flows back onto the grid *"The credit per kilowatt hour for kilowatt hours delivered into the utility's distribution system shall be either off the following…"* [8 TR 3642.]

The Company erroneously interprets "excess generation" as being synonymous with power outflow, which is clearly not the case, as "excess generation" is that portion of power outflows not used to (net) against metered power inflows during a billing period.

Additionally, the Company reveals its confusion regarding interpretation of Section 177(4) by claiming that the outcome of Mr. Ozar's explanation that two distinct compensation methods for power outflows emerge from a reasonable interpretation of Section 177(4) necessarily results in compensating DG customers for their onsite use of generation, which is false. This confusion again emanates from the Company's error of taking the concluding sentence in Section 177(4) out of context with the whole statutory provision. Mr. Serna erroneously states:

> I believe Mr. Ozar is mischaracterizing Section 177(4) because the credits described in 177(4) only apply to excess generation that flows

> back into the grid "*The credit per kilowatt hour for kilowatt hours delivered into the utilities distribution shall be either of the following…*" The language is clear that the application of the credits does not apply to generation used onsite. Generation used onsite allows a distributed generation customer to avoid paying the full retail rate for that amount of generation, but the utility does not compensate a distributed generation customer with "credit" at the full retail rate. [*Id.*]

In making this claim, the Company was responding to Staff witness Ozar's explanation that:

> If DTE's interpretation was accepted, then necessarily its own request to implement an Inflow/Outflow billing mechanism would conflict with Section 177(4) since the statutory provision provides compensation at the full retail rate for power outflows up to the level of power inflows during the billing month, whereas DTE is requesting to compensate [all] power outflows during a billing period at the monthly average real-time LMP. [8 TR 3427.]

Staff's interpretation that Section 177(4) separates power outflows into two distinct compensation methods, (energy netting up to power inflows during a billing period, and dual crediting formulas for outflows carried forward into future billing periods—i.e. modified net metering), is rationally consistent with a holistic reading of the statute and does not invoke any need whatsoever to address on-site usage of locally-sited generation.

In addition, the Company notes that PA 342 amended Section 177(4) by replacing the phrase "*net metering customers*" with the phrase "*distributed generation customers*". (8 TR 3640-3641.) The Company thus claims that because the term "net metering customer" was removed from Section 177(4), the section no longer applies to grandfathered net metering customers and is thus no longer limited to modified net metering customers but applicable to any and all cost-based

DG tariffs approved pursuant to PA 341 Section 6a(14). *Id.* Staff vigorously disagrees that Section 177(4) universally sets the compensation rate for all distributed generation customers at either of the two delineated pricing options specified by the statute.

Staff posits that the Legislature's modification of Section 177(4) to "*Notwithstanding any law or regulation, **Distributed Generation** customers shall not receive credits for electric utility transmission or distribution charges*" does not negate the fact that such section remains exclusively applicable to the modified net metering billing method. DTE argues that due to this wording change, Section 177(4) no longer applies to net metering, but strictly to the cost-of-service based "tariff" implemented pursuant to PA 341 Section 6 (a) 14.

However, the term "distributed generation" or "distributed generation program", as used in PA 342 is a broadly inclusive term encompassing multiple billing methods, including Modified Net Metering (with added grid charge), True Net Metering (with added grid charge), Inflow/Outflow or any other cost-of-service based billing method (tariff) that meets the requirements of PA 341 Section 6(a) 14.

The fact that PA 342 requires the Commission to "[E]stablish a distributed generation program by order issued not later than 90 days after the effective date of the 2016 act …" implies that the new distributed generation program must be in place (90 days after April 20 2017) well before the Commission is required to conduct a study on an appropriate tariff reflecting equitable cost of service (1 year after April 20, 2017) or the Commission is required to approve "such a tariff" (in any rate case filed after June 1, 2018.) For this reason, the replacement of the phrase "net metering" with the term "distributed generation" in Section 177(4) is inclusive of grandfathered modified net metering with an added grid charge.

In its July 12, 2018 Order in MPSC Case No. U-18383, the Commission recognized that the new "Distributed Generation program" is inclusive of net metering by complying with the Legislature's directive and establishing continuation of net metering until the new cost-based tariff is approved. *In re Commission's own motion to implement Sections 173 and 183(1),* MPSC Case No. U-18383, 7/12/2017 Order, p 6. The Commission found that the current net metering program should continue as the Distributed Generation program until new DG tariffs are approved in rate cases filed after June 1, 2018. *Id.* at 4. Thus, the essential basis upon which DTE claims that the Commission is bound by Section 177(4) in setting outflow compensation rates (that the term Distributed Generation replaced Net Metering in Section 177(4) is false.

Therefore, regarding the legal issue of applicability of Section 177(4), the Company is incorrect in its position that any proposed DG tariff is limited in its outflow compensation methodology to the two methods provided for modified net metering in Section 177(4). The Staff maintains its assertion that the Commission is not bound by Section 177(4) for the cost-based DG tariff it establishes pursuant to PA 341 Section 6a(14) unless it were establishing a modified net metering tariff with an added grid charge to ensure a cost-of-service basis for the tariff.

b. Staff recommends the ALJ and Commission base outflow compensation on the Company's power supply component less transmission costs.

Staff, on both a policy and technical basis, disagrees with the Company's proposed utilization of real-time monthly average LMP for compensating DG customer outflows. Staff instead supports the usage of the utility's power supply component less transmission costs for this case.

Mr. Serna summarized the reasoning behind the Company's proposal to compensate DG customer outflow at LMP by stating: 1) that the Company's generation capacity is required to serve customer load when their generator is not producing (8 TR 3601); 2) the Company has no temporal or total production contract with DG customers (8 TR 3603); and 3) that the primary purpose of DG customer generation is to offset onsite consumption. *Id.* Taken together, Staff witness Ozar explains that these arguments underpin the Company's assertion that DG customer generation provides no capacity value, and therefore leads to the Company's conclusion that LMP is the best compensation for DG customer outflow. (8 TR 3428.) However, Mr. Ozar points to a crucial difference in how the DG customer is viewed by the Company and Staff. Mr. Ozar states that if one focuses solely on the individual DG customer, which is apparently the perspective taken by the Company, it "will lead to the erroneous conclusion '…that there is no tangible capacity value or capacity offset provided by the distributed generation'." (8 TR 3430.) Instead, evaluation of the capacity value of a small customer DG program on a coincident aggregate program basis will reflect the capacity value of the entire program itself as a virtual generator. *Id.* Once this capacity value, on a program-wide basis can be established, it can be incorporated into the outflow compensation formula and allocated to individual customers. *Id.* Mr. Ozar further explains that the Commission does not set utility rates on a single customer basis, but instead considers the whole customer class when setting rates. *Id.* Similarly, the capacity value of a DG program should not be determined based on the capacity value, if any, of a single customer, but should be based on the program as a whole. *Id.* The Company argues that it must retain generation capacity to serve the loss of a DG customer's generation. (8 TR 3601.) However, it is highly unlikely that the Company will have to deal with the loss of every customer-sited generation system simultaneously. (8 TR 3431.) Thus, Staff maintains that the Company should undertake a power-outflow capacity study subsequent to the implementation of the tariff to confirm that coincident aggregate program outflows are relatively stable and predictable and to quantify the effective DG outflow capacity and value. *Id.*

Until the time when sufficient data is available from a power-outflow capacity study, Staff maintains that the proper outflow compensation for the Inflow/Outflow tariff should be the power supply component of the DG customer's retail rate, excluding transmission. (8 TR 3433.) The Company's reliance of the LMP presupposes zero capacity value from DG customers. As explained above, a power outflow study can reveal the stable, predictable DG outflow capacity and value. Furthermore, Staff's proposed outflow compensation methodology

> is simple, understandable to customers, creates a close connection between the new compensation rates under the Inflow/Outflow billing method and existing compensation under NEM, and avoids the primary subsidy related to NEM which is the inclusion of the

distribution charge (of the underlying sales rate schedule) in the outflow compensation formula. *Id.*

Also, Staff's recommended outflow compensation methodology results in a more measured pace of adjustment from the existing level of compensation under NEM. *Id.* Thus, Staff's recommendation is more in line with the Commission's statement in its April 18th, 2018 Order in MPSC Case No. U -18383, where it said "[a]s the DG program evolves and more data becomes available, the Commission will be better able to assess the cost and benefit impacts and conduct rate design consistent with COS principles." (April 18, 2018 Order, p 17; 8 TR 3434.)

In sum, Staff recommends that the Commission adopt Staff's proposed methodology of the power supply component of the retail rate, excluding transmission costs, for compensating DG customer power outflows. The Company's LMP approach should be rejected for the reasons described above. Furthermore, to implement Staff's proposed methodology, the Company's power supply rates should be unbundled to separate transmission costs from capacity and non-capacity power supply charges. (8 TR 3437.) Staff agrees with the Company in its rebuttal that the unbundled power supply charge could be delineated in the DG rider, rather than the underlying retail tariff. Lastly, Staff recommends the Commission direct the Company to undertake a comprehensive multiyear power Inflow/Outflow study upon implementation of the tariff. *Id.* The results of this study will form the basis of future Inflow/Outflow rate design. *Id.*

VII. Staff recommends modifications to the Company's electric vehicle Charging Forward program.

A. The Commission should approve the Company's Charging Forward program with Staff's adjustments.

Staff makes five recommendations for the Company's proposed Charging Forward EV program. These recommendations are for the Commission to: 1) adopt the Company's proposed Charging Forward Program with Staff's changes; 2) authorize an increase in funding by $6 million for a total of $18 million over three years; 3) authorize the inclusion of additional pilot objectives and expanded available capital for make-ready opportunities through an increased spending cap; 4) make approval of the program contingent upon remediation of several deficiencies discussed below; and 5) set performance standards for the program. (8 TR 3409-3410.) Staff argues that it is reasonable, prudent, and in the public interest for the Commission to approve this program, in addition to expanded funding to meet the additional "controlled charging objectives and solidify market transformation." (8 TR 3411.) Further, Staff asserts that an enhanced Charging Forward program will significantly accelerate the adoption of plug-in electric vehicles (PEVs) in the Company's service territory which will likely result in system-wide benefits for ratepayers. *Id.*

Put broadly, the Company's position is that increased EV adoption, supported by the Company's Charging Forward Program, will manifest downward pressure on rates benefitting all the Company's ratepayers, regardless of whether they own an electric vehicle. (8 TR 3582-3583.) The Company's proposed program consists of customer education and outreach, residential smart charger support, and charging infrastructure enablement. (8 TR 3563.) Regarding residential smart charger support, the Company asserts that because the majority of PEV charging will take place at ratepayers' homes, it will be most beneficial for most of this charging to take place during off-peak hours and that the drivers switch to Level 2 charging from Level 1. (8 TR 3565.) Therefore, the Company seeks to incentivize the technology switch through a rebate up to $500 for approximately 2,800 residential customers, and for purposes of qualifying for the rebate have customers enroll in year-round time-of-use (TOU) rates and future demand response (DR) programs. (8 TR 3565-3566.) The Company maintains that the required enrollment in TOU rates will shift most of the EV load to off-peak hours which will more efficiently utilize existing Company generation and distribution resources. (8 TR 3567.)

The charging infrastructure enablement portion of the Charging Forward program consists of three components: direct current fast charger (DCFC) stations, Level 2 stations, and fleet charging stations. (8 TR 3568.) For DCFC, the Company proposes a make-ready model in which the Company would fund the portion of the investment for the EV service connection, which includes costs related to the connection from the transformer to the meter. *Id.* For the EV supply infrastructure, which includes after the meter costs for the panel, conduit and wiring, the Company would provide a fixed rebate for this infrastructure of $20,000. (8 TR 3569; 3571.) And, for the actual charging station, the site host would be responsible for the purchase, operation and maintenance of the charging station. (8 TR 3569.)

The Company plans to focus Level 2 charging infrastructure primarily in workplaces and multi-unit dwellings and will be seeking site hosts interest in providing public Level 2 stations to increase visibility and decrease range anxiety. (8 TR 3571.) The Company claims that workplace charging will function as an EV showcase and thereby positively affect EV adoption and interest among potential site hosts. (8 TR 3572.) Further, public Level 2 charging will also increase EV awareness and charging "topping off". (8 TR 3573.) Similar to the DCFC construct, the Company will offer a rebate, in the amount of $2,500, for after-the meter infrastructure per Level 2 charging port. *Id.* The Company based this amount on benchmarking these costs for a collection of other utilities who have invested in similar infrastructure. *Id.*

The fleet charging component consists of the Company providing make-ready charging infrastructure for the following four fleet categories: 1) public transit buses; 2) school buses; 3) delivery vehicles; and 4) shared mobility services. (8 TR 3573-3574.) The Company asserts that for these categories of transport, fuel and maintenance savings will be substantial and electrification of these types of transport will also have a significant positive impact on air quality. (8 TR 3574.) The Company proposes an after-the-meter rebate for fleet charging infrastructure equal in value to the capital cost up to the meter for each charging station. (8 TR 3575.)

The Company's proposed cost is $13 million for the Charging Forward program. (8 TR 3579.) This cost includes O&M and the proposed investment is spread from 2019 to 2022, with $4.5 million of these costs estimated to take place in the projected test year. (8 TR 3580; Exhibit A-12, Schedule B5.9.) The Company asserts that it arrived at these costs by benchmarking other EV programs, soliciting input from industry experts and sampling station costs across the Company's electric service territory. (8 TR 3581.) The Company is proposing to include expenditures for rebates for DCFC, Level 2, and fleet infrastructure and residential smart charger in a regulatory asset. (Exhibit A-12, Schedule B5.9.) The Company is requesting to amortize this regulatory asset over five years. (8 TR 3581.)

1. Staff proposes several piloting additions.

Staff, through its witness Robert Ozar, put forth several piloting additions to enhance the Charging Forward Program and discussed deficiencies that should be remediated prior to approval of the program. Regarding the additional pilot objectives, Mr. Ozar explained that a decade has elapsed since the Commission authorized a $5 million Low Income and Energy Efficiency Fund (LIEF) PEV pilot/grid study. (8 TR 3411-3412.) In that time, the PEV landscape has undergone significant change. *Id.* As such, it is imperative that the Company undertake a new study to update its understanding of, among other things, the potential for adverse grid impacts associated with charging. *Id.* Staff recommends that a preliminary study framework which includes key partnerships, estimated costs, and study objectives be filed with the Commission within 6 months of a final order in this case. (8 TR 3412.)

Staff recommends that the school bus pilot be expanded beyond the Company's investment in make-ready infrastructure to include a vehicle-to-grid pilot that tests the provision of storage services, demand response services, and other ancillary services. *Id.* an expanded school bus pilot incorporating Staff's recommendations will require the provision of credits for the value of energy services provided and a financial offset to the school system to cover the risk of accelerated battery degradation. *Id.* The additional costs associated with an expanded school bus pilot should be covered by the increased $6 million in spending for the Charging Forward Program recommended by Staff. *Id.* Staff also recommends that the Company undertake an 80A charging pilot within the medium/heavy duty vehicle component of the Charging Forward Program because it is an emerging charging technology that the Company should explore and as of yet has not been extensively vetted in Michigan. (8 TR 3413.)

2. Staff recommends the Company address several deficiencies in its program.

a. Mitigation of stranded investment

Staff, through Mr. Ozar's analysis, identified several deficiencies in the Charging Forward Program. First, due to the potential for stranded investment, Staff maintains the DCFC chargers should occupy prime locations within the Company's service territory. (8 TR 3414.) However, if the Company is to invest in DCFC charging in these prime locations, it must do so with an eye towards potential future upgrade to its proposed 50 kW make-ready infrastructure to accommodate ultra-fast 150-350 kW charging rates. *Id.* The essential point is that if stranded investment is to be avoided, the Company should take proactive measures to future-proof the make-ready infrastructure associated with those DCFC sites that are most likely to be upgraded in response to DCFC infrastructure technology moving beyond the 50kW charging paradigm currently contemplated in the Charging Forward Program. Staff believes that if ratepayers' investment is to be protected, then the mitigation of near-certain stranding of program-funded assets should take precedence over any interim loss in interconnection efficiency caused by temporarily oversized interconnections. *Id.* Therefore, Staff urges the Company to invest in DCFC ultra-fast 150-350 kW infrastructure in these prime locations.

b. The sale-for-resale prohibition should be removed.

Next, Staff posits that the current DTE tariff provision regarding "sale for resale" at publicly available PEV charging stations should be lifted. (8 TR 3414.) Staff argues that a per kW rate will facilitate the maturing of the competitive market for publicly available PEV charging because a uniform pricing standard will aid in the development of robust competition between charging providers. (8 TR 3415.) Additionally, a per kW rate at publicly available charging stations will allow for an accurate comparison between commercial charging stations and the preferred at-home charging alternative. *Id.* Through the rebuttal testimony of its witness Serna, the Company stated that volumetric, per kW pricing, is an imprecise signal to customers and does not correlate with the Company's fixed and demand-based investments. (8 TR 3617.) The Company makes this argument despite the fact that its own Rate D1.9 "Experimental Electric Vehicle Rate" is a volumetric, per kWh, time-of-use (TOU) rate structure. The Company maintains that only customers qualifying for the Company's Electric Rider No. 4 may engage in the resale of service under limited circumstances. *Id.* Staff maintains the position that the Company's prohibition on sale for resale at publicly available charging stations frustrates the Company's own stated objective of ensuring that most EV charging load occurs during off-peak hours through enrollment in the Company's TOU rates. (8 TR 3415.) The existing tariff prohibition on sale for resale contributes to a persistently high level of "free" charging at publicly available charging stations, thus eliminating the incentive to shift to off-peak hours for charging. *Id.*

c. Staff recommends elimination of the monthly flat fee option in rate schedule D1.9, and that the Company file an application to amend rate schedule D1.9 to allow for submetering..

There are two rate options under Rate schedule D1.9: option 1 consists of Time-Of Use (TOU) pricing; and option 2 is a monthly flat fee. Staff supports the elimination of rate option 2 under the Experimental Electric Vehicle Rate, rate schedule D1.9. (8 TR 3417.) Option 1 TOU pricing surpasses any benefits experienced from option 2; and the experimental flat fee in option 2 has run its course. *Id.* Further, Staff asserts that rate D1.9 does not provide for the testing of potentially cost-effective submetering options to address the lack of enrollment by residential customers in the EV TOU rate. *Id.* Thus, the Company is limited to promoting the whole home TOU rate for residential EV charging. In addition, lacking submetering provisions in the D1.9 tariff, the Company is limited in its options to expand EV charging at multi-unit dwellings (MUD's), which is a core objective of the Charging Forward Program. *Id.*

In rebuttal testimony, Company witness Serna supported Staff's position with respect to closing the D1.9, option 2 flat fee for new enrollment effective May 31, 2019. (8 TR 3618.) Additionally, the Company will move all 173 customers enrolled in option 2 onto a new rate by December 31, 2019. *Id.*

Regarding Staff's recommendation to amend rate schedule D1.9 to include two new submetering options, Staff asserts that these additions to the tariff would directly address the lack of customers choosing to have a second meter for charging purposes and would also provide the Company with new tools to address market barriers for controlled EV charging. *Id.* The first option involves providing for AMI submetering behind a customer's existing billing meter to separately measure EV charging load. *Id.* Staff asserts that this could reduce installation costs because the AMI submeter could be connected to the customer's service panel. Staff believes that the AMI submetering configuration could allow for customers to be charged for their non-EV load at their primary rate with EV billed at the D1.9 EV TOU rate. (8 TR 3418.) This approach has already been approved by the Commission for Indiana Michigan Power (I&M) in *In re Application of I&M for Approval of Tariff RS-PEV,* MPSC Case No. U-20282 as a potentially cost-effective work-around the second meter requirement for EV TOU rate enrollment. MPSC Case No. U-20282, 11/8/2018 Order, p 2. Staff's second proposed option to rate schedule D1.9 would allow for the piloting of novel approaches to bill customers using non-utility owned submetering technologies such as vehicle on-board metering and communication or smart/connected chargers to submeter PEV load and provide access to the EV TOU rates under D1.9. *Id.*

Of particular significance, the second option in Staff's proposed amendment to rate schedule D1.9 would allow access to EV TOU pricing to tenants of multi-unit dwellings (MUDs) who may otherwise not have access to dedicated parking nor the ability to physically or economically connect PEV charging stations to the tenant's service panel. (8 TR 3418-3419.) These expanded metering options could provide the framework for building owners to pass-through the EV TOU rate for charging at publicly available Level 2 stations at the MUD to residential tenants. (8 TR 3419.) Staff recommends that the Commission direct the Company to file an application within 30 days of its order in this case to amend rate D1.9 to include these submetering options. *Id.*

In its rebuttal, the Company agreed that these options are important elements of PEV charging that need to be explored. (8 TR 3618.) However, the Company believes that it is premature to pilot one of the several available technologies prior to devoting more time to evaluate the accuracy, security and cost-effectiveness of all available submetering options. *Id.* As such, the Company does not agree that this piloting objective should be included in the current Charging

Forward Program. *Id.* The Company does commit to continue to investigate these options and provide the results in one of the annual reports for the Charging Forward Program. (8 TR 3619.) Staff rejects the Company's reasoning and counter-proposal on the D1.9 amendment because it places the "cart before the horse". The Company needs the tools (in the form of tariff language) to address two critical issues that could negatively impact the cost and reliability of the electric grid as EV adoption increases: 1) the lack of uptake of its Experimental Electric Vehicle tariff by residential customers; and 2) the mitigation of barriers preventing "home charging" for tenants of multi-unit dwellings (MUD's). (8 TR 3417-3418.) This tariff fix is needed before the Company implements the program, not after. With substantive, but generic language additions to Rate Schedule D1.9, the Company would be granted the flexibility to explore a wide range of "separately-metered" options that are not now possible to pilot. At this time, Staff is not recommending any particular amendatory language to be included in the recommended filing. However, the tariff language should include a waiver of availability (i.e. at the company's discretion) similar to Staff's recommendation for amendment of the Company's rules relating to Contributions in Aid of Construction: "…as it is necessary for the utility to: 1) actively manage site locations and; 2) control pilot expenditures, DTE should have the unilateral right to suspend Contributions in Aid of Construction…" (8 TR 3421.)

It is Staff's position that the only way to make real progress in ensuring that all EV owners in the Company's service territory can access the D1.9 TOU rate is via extensive experimentation founded upon innovative new sub-metering options added to such rate schedule. In evaluating Staff's recommendation, the Commission should note that the Company's D1.9 tariff is already explicitly entitled an "Experimental Electric Vehicle Rate".

Resolution of these issues are fundamental to approval of the proposed Charging Forward Program, as metering barriers impede residential enrollment in the Experimental Electric Vehicle Rate, and market barriers in the MUD market result in it being underserved. Staff's proposed new submetering options "would directly address the issue of lack of uptake of the second meter option for residential customers and would also provide the Company with new tools to address market barriers for controlled PEV charging". (8 TR 3417.)

d. Staff recommends annual reporting and the convening of a technical conference to gain input and updates from the public and interested stakeholders.

Staff further took issue with the fact that the Company's proposal does not provide for public updates or input into the program and raised concerns that the Company only intends to apprise the Commission of the piloting outcomes after the close of the program which will occur three years into the future. (8 TR 3420.) Further, because the current Charging Forward Program is largely conceptual at this point, Staff recommends that the Commission direct the Company to file a status report prior to program implementation and annual reports thereafter. *Id.* Further, Staff intends to convene a technical conference with the Company, intervenors and interested stakeholders to obtain public awareness and input. *Id.*

The Company disagreed that its proposal does not provide for public updates and input. (8 TR 3619.) The Company pointed to its direct testimony where it stated that it will seek feedback in the implementation phase of the program as it did in the development phase. *Id.* However, the Company supports Staff's recommendation to convene a technical conference with interested stakeholders. *Id.* Further, the Company agrees with Staff's recommendation to file annual reports summarizing the implementation progress, but the Company does point out that the level of detail will differ from that planned for the end of the three-year program. *Id.* And, the Company does not agree to file a status report in this docket prior to implementation. (8 TR 3620.) The Company maintains that the testimony and order resulting from this case will provide stakeholders all the information they will need prior to implementation. *Id.* Staff accepts the Company's position on this point.

e. Staff recommends the addition of three performance objectives to the Charging Forward program.

Staff recommends three performance objectives for the Charging Forward Program: 1) that the Company maximize program participation at minimum cost; 2) aggressively test new and novel practices and technologies to ensure that new load associated with EV charging maximizes net benefits to all the Company's ratepayers; and 3) that investments in make-ready infrastructure serve double duty by: a) directly addressing core barriers, such as range anxiety, that are frustrating the adoption of PEVs; and b) are leveraged by the Company to learn reasonable and practicable ways to actively manage charging times and locations, to minimize required investment in new distribution infrastructure and to obviate adverse grid impacts related to uncontrolled charging. (8 TR 3420-3421.) The Company stated that it recognizes the importance of these elements and has incorporated them into the overall Charging Forward Program objectives. Company witness Serna provided that he updated the program objectives to:

> • Help customers realize the benefits of EVs and reduce the barriers to adoption;
>
> • Efficiently integrate EV load with the DTE Electric distribution system by actively managing charging times and ensuring the net benefit of EV load accrues to all DTE 11 Electric customers;
>
> • Fully subscribe the Charging Infrastructure Enablement component through thoughtful partnerships, maximizing participants while minimizing necessary infrastructure investments; and
>
> • Improve our understanding of EV load characteristics and its impact on the distribution system to prepare for widespread EV adoption in the future. [8 TR 3621.]

Staff strongly urges the Commission to approve the three performance-based objectives, as delineated by Staff witness Ozar, as essential to approval of the "Charging Forward Program". In making this recommendation, Staff notes that the Company would be earning a return on all deferred expenditures, including customer rebates. In addition, Staff notes that it is concerned that the program focus, as framed by the Company, is heavily steered toward EV charging station deployment, and the expected accelerated adoption of electric vehicles. Adoption of the performance-based objectives will guide the Company toward a more balanced approach, with the mitigation of adverse grid impacts through intense piloting of managed charging concepts as the predominant goal of the program.

f. Staff recommends changes to tariff language regarding Contribution in Aid of Construction.

Staff asserts that the Company must have the right to determine which sites will be included in the Charging Forward Program because the Company must actively manage site locations and control pilot expenditures. (8 TR 3421.) Therefore, Staff recommends that the Company should have the unilateral right to suspend Contributions in Aid of Construction (CIAC) at any Level 2 or DCFC site included in the pilot, and thus fully fund the cost of interconnection. *Id.* In order to implement the suspension, Staff recommends the Company file amendatory language in its CIAC tariffs. *Id.* The Company agrees. The Company will file amendatory language in its tariff in Section C6.1(16). (8 TR 3621-3622.)

g. Staff recommends costs related to delayed pilots be included in the program.

Staff noted that seven of the Company's pilots that were intended to support the Charging Forward Program are significantly delayed. (8 TR 3421.) Staff proposes that the unfunded cost of these pilots which are implemented after the order in this case be included in the program for cost recovery via the regulatory asset. (8 TR 3422.) The Company agreed and will include any 2018 pilot costs subsequent to the order in this case in the Charging Forward costs and reporting. (8 TR 3622.)

VIII. Requests for Accounting Authority

The Company made requests for accounting authority related to the following, which are discussed further below: electric vehicle program (Charging Forward), Customer 360 post-implementation O&M expenses, tree trim surge costs, and time-of-use implementation expenses.

A. Staff recommends the Commission deny the Company's regulatory asset request for its Charging Forward Program and approve Staff's regulatory asset Charging Forward proposal.

The Company is requesting authority to use account 182.3, Other Regulatory Assets to record rebate costs to customers associated with Charging Forward program. (7 TR 3330.) The Company is also requesting recovery of these deferred costs over a five-year period through amortization expense in O&M in this case. *Id.*

Staff witness Ozar recommends an alternative to the Company's Charging Forward Program which, if adopted, would render the Company's proposal inapplicable. (9TR 4056.) Contingent upon adoption of Mr. Ozar's Charging Forward recommendations, Staff is proposing the Commission authorize a regulatory asset to recognize the deferred costs in account 182.3, Other Regulatory Assets, with a five-year amortization beginning the year following the deferral of costs to the regulatory asset account. Staff's proposal for regulatory asset treatment and amortization mirror the Commission's recent Order in Consumers

Energy's electric rate case, MPSC Case No. U-20134 regarding Consumers Energy's proposed EV Program costs. (9TR 4056-4057.) Staff's proposal should be adopted by the ALJ and Commission in this case.

Company witness Uzenski disagreed with beginning amortization the year after the costs are incurred and delaying recovery of the unamortized balance until after Staff's review. She opined that a portion of the deferred costs will be amortized but never recovered. (7 TR 3348-3349.) She further opined that the Company should not have to absorb the expenses for the Charging Forward Program. (7 TR 3349). Staff agrees that some costs may not be recovered due to regulatory lag, but it also notes that depending on timing of when DTE Electric were to file rate cases the Company could also over-recover some of these costs. This would occur if the amortization expense is included in rates from the last approved rate case and the Company does not file a rate case coincident with when the ending of the amortization period of the costs. Also, of note, Ms. Uzenski agreed that a prudency review of costs by Staff is appropriate. (7 TR 3349.)

Therefore, Staff stands by its recommendation for regulatory asset treatment, five-year amortization period, amortization timing of deferred costs, and allowance in rate base and expense after a prudency review occurs in the Company's next rate case. (9 TR 4057-4058.) Staff's recommendation is a prudent measure to guard against ratepayers paying for costs which are projected but may not be incurred, while at the same time allowing the Company an opportunity to recover actual incurred costs as part of future rate cases. Therefore, Staff recommends the ALJ and Commission adopt its proposed Charging Forward regulatory asset proposal.

B. Regulatory asset for Customer 360 post-implementation O&M expenses.

The Company implemented a new Customer Relationship and Billing System in 2017 called Customer 360, (C360). In the Company prior rate case, *In re DTE Electric Rate* Case, MPSC Case No. U-17666, the Company deferred $47 million for project expenses related to C360 in Account 182.3, Other Regulatory Assets and they are being amortized over a 15-year period. The Company further incurred another $16.6 million of C360 costs during 2017 and has requested that those costs be included in the regulatory asset balance and amortized as well. (7 TR 3327-3328.) Staff does not oppose the request.

C. Regulatory asset for tree trim surge costs.

The Company included a $7,053,000 revenue requirement related to a regulatory asset for tree trim surge costs on Exhibit A-11, Schedule A1. Staff has completely removed the $7,053,00 revenue requirement for tree trim surge costs from the instant case. (Appendix A, line 9.) Alternatively, Staff has recommended a reasonable increase to tree trim O&M expense of $13,007,000. (Appendix C, line 10.) Staff presents a detailed discussion of its position regarding the proposed regulatory asset for the tree trimming surge costs in section V.A.2(a)(viii).

D. Regulatory asset for time-of-use implementation expenses.

Staff recommends the ALJ and Commission approve the Company's regulatory asset request related to time-of-use subject to modifications discussed and supported by Staff in the Cost of Service and Rate Design Section below. (8 TR 4055.)

IX. Cost of Service and Rate Design

After calculating the Company's rate base, its ROE, and its adjusted net operating income, Staff calculated the Company's revenue requirement. Staff used this revenue requirement to allocate costs and design rates.

A. The Commission should order the Company to conduct a new General & Intangible (G&I) study in the Company's next rate case.

The Company used a G&I direct assignment study performed by the Company in 2008 to functionalize a General and Intangible plant in the cost of service study used in this case. Staff recommends the Commission require the Company perform an updated G&I direct assignment study with the most recent data available and use the updated study in the preparation of the Company's next general electric rate case. (8 TR 4267.) It has been 10 years since this study has been performed and, in Staff's opinion, that is enough time to warrant a new study. *Id.*

No other parties took a position on this issue. For the reasons listed above, the ALJ should recommend, and the Commission should approve, a requirement that the Company perform a new G&I direct assessment study to be filed and used in the Company's next general electric rate case.

B. The ALJ should recommend, and the Commission should adopt Staff's recommendations regarding residential and commercial secondary customer charges, so each remains at present levels.

The Company is proposing to increase the residential customer charge from \$7.50 to \$9.00 and the commercial secondary customer charge from \$11.25 to \$15. (8 TR 3868; 5 TR 1430.) These recommendations were based on Company witness Lacey's proposed method which produced "customer" costs per customer of \$45.53 for residential and \$175 for commercial secondary. (7 TR 3221.) This is inappropriate. Staff proposed to leave the customer charges at the existing levels based on its own customer charge analysis, a method that has been approved by the Commission as recently as in Case No. U-18014. (8 TR 4267-4268.)

Company witness Lacey's method of calculating the residential and commercial secondary customer charges is over-inclusive and not a true representation of the costs the Company has incurred to connect customers to the system. Staff witness Gottschalk testified:

> The Company inappropriately included distribution plant costs that are demand-related, such as land and rights, improvements, station equipment, storage batteries, poles and fixtures, overhead and underground conductors, underground conduit, line transformers, general and intangible plant, tree trimming, working capital, future use, CWIP, and *all* distribution O&M, depreciation, and taxes allocated to the respective class in its development of the customer charges. Including costs, like these, which are not directly linked to a customer's mere existence, is contrary to the Commission's Order in MPSC Case Nos. U-4771 and U-4331:

> "Specific distribution plant such as meters and service drops used exclusively for a given customer shall be treated as customer related. All other distribution plant shall be treated as demand related." (MPSC Case No. U-4771, 5/10/76 Order, p 2.)
>
> "The maximum allowable service charge would be limited to those costs associated directly with supplying service to customer. Only costs associated with metering, the service lateral, and customer billing are includable since these are the costs that are directly incurred as the result of a customer's connection to the gas system." (MPSC Case No. U-4331, Order, p 30, January 18, 1974).

> Despite the fact that U-4331 was a gas case, the same philosophy applies to electric utilities. Most of the expenses included by the Company do not vary with the number of customers and are not directly incurred as the result of a customer's connection to the system. Consequently, these expenses should not be included in the service charge. The Commission has rejected DTE's customer charge calculation method in the Company's past three rate cases, U-18255, U-18014 and U-17767:
>
> > "The ALJ noted that DTE Electric's calculation of this charge was rejected by the Commission in both the 2017 order, pp. 105-110, and in the December 11, 2015 order in Case No. U-17767, pp. 119-120 (the next prior rate case for this utility).
> >
> > …As in the past, the Commission rejects DTE Electric's inclusion in fixed monthly costs of items that are unrelated to the marginal cost of customers connecting to the system." (MPSC Case No. U-18255, Order, pp 64-65. April 18, 2018).
> >
> > [8 TR 4268-4270.]

Staff's method, which can be found in Exhibit S-6 Schedule F1.3, is the most appropriate method to calculate the customer charges for these classes as Staff witness Gottschalk testified that it "includes only costs directly related to supplying service to the customer, including meters, services, and customer service, which adheres exactly to the standards laid out by the Commission in the previously quoted Order in Case No. U-4331. Additionally, Staff's method was approved by the Commission in the DTE Electric rate case No. U-18014:

> DTE Electric did not provide any new evidence or analysis that would support adopting the company's proposed study, and therefore, the Commission adopts the Staff's proposed customer charge calculation. [MPSC Case No. U-18014, Order, p 110, January 31, 2017.]

In that case, Staff witness Charles E. Putnam detailed Staff methodology, providing:

> Staff included only meter, overhead, & underground services, customer accounting costs, and customer service expenses in Staff's calculation. Specifically, Staff removed uncollectibles, poles & fixtures, OH conductor, UG cable and conduit, line transformers, distribution system-customer related, general plant, employee pension and benefits, administrative and general, and FICA costs from Staff's calculation. [MPSC Case No. U-18014, Direct Testimony of Charles E. Putnam, 5 TR 1347.]

Witness Douglas Jester, on behalf of MEC, NRDC, SC, EIBC, IEI, and EC, recommended that the Commission should reject the Company's proposed customer charge increases and stated that the Company's method has been rejected in previous cases. (6 TR 2197-2198.) He goes on to state that the Commission has "established a clear precedent that monthly customer charges are to be based on those costs that directly vary with the number of customers, such as metering, billing, customer service, and service drops." *Id.* He also contends that "the Company has made no calculation or representation in this case that these costs exceed the current monthly service charge of $7.50," and should therefore be rejected. *Id.* Staff agrees with these assertions.

Witness Karl Rabago, on behalf of MEC-NRDC and SC, also opposes the Company's proposal to increase the residential and small commercial customer charges. (6 TR 2477). Witness Rabago testified that "the fixed customer charge should be reserved for the recovery of costs that vary exclusively with the number of customers and the cost to connect those customers to the grid" and that this has been the Commission standard. (6 TR 2477.) This argument is also in line with Staff's position.

The Attorney General's witness, Sebastian Coppola, opposes the Company's proposed increases to the residential and commercial secondary customer charges. (5 TR 1688.) He argues the proposed increases combined with the increases approved by the Commission in the Company's last rate case would result in increases of 50% and 60% respectively in about a year and would be hard for smaller customers to absorb. (5 TR 1687.) He also claims the increases would defeat the objective of rate gradualism. *Id.* While Staff relies on its cost-based method to assess the customer charge, Staff agrees with witness Coppola's recommendation that the Commission reject the proposed increases.

The Commission should continue to support the method it has in the past and adopt Staff's proposed customer charges and attendant method in the instant case, which results in residential and commercial secondary customer charges remaining at present levels.

C. The Commission should continue to endorse the capacity cost method it ordered in cases U-18248 and U-18255.

The Company's capacity cost calculation strays from the approved method ordered by the Commission in cases U-18248 and U-18255, which ruled that revenue from gross energy market sales net of fuel costs be subtracted when determining capacity costs for the SRM capacity charge. Staff witness Gottschalk testified:

> As stated in the law, revenue from all energy market sales, net of fuel costs, needs to be subtracted from the calculation of capacity costs, not excess sales above the Company's load. This was a point debated in Case No. U-18248 and the Commission did not agree with DTE's interpretation of this statue:
>
> > "Section 6w(3)(b) goes on to list amounts that must be deducted from embedded costs, including (net of projected fuel costs) all energy market sales, off-system energy sales, ancillary services sales, and unit specific bilateral contract sales. DTE Electric offered deductions of $49 million on an annual net net (net of projected fuel costs, and net of total purchases or total losses) basis under Section 6w(3)(b). 3 Tr 210-213. However, the statute says nothing about making this determination on an annual net net basis. The statute says 'subtract all non-capacity-related electric generation costs . . . net of projected fuel costs, from all of the following: (i) All energy market sales. (ii) Off-system energy sales. (iii) Ancillary services sales.' MCL 460.6w(3)(b). The plain language of the statute provides no support for DTE Electric's proposed interpretation." 11/21/17 Commission Order in Case No. U-18248, p 66. [8 TR 4271.]

The Company disregarded this ruling and continued to only deduct revenues net of fuel costs from excess sales back into the MISO market. This is the same method that was denied by the Commission in previous cases. The Commission adopted a methodology that uses all revenue from energy market sales and all revenue from ancillary services sales, which is the same methodology used by Staff in the instant case:

> The Commission finds that the methodology for establishing the state reliability charge supported by the Jennings and Smith testimony is reasonable, appropriate, and consistent with Section 6w. [MPSC Case No. U-18248, 11/21/17, p 69.]

Following the Commission's approved method in cases U-18248 and U-18255, Staff witness Gottschalk presented Staff's capacity revenue requirement:

> Staff's capacity revenue requirement is derived using the same method as ordered in those cases with updated costs from the instant case. Staff's calculation is shown on Schedule F1.4 and results in a capacity revenue requirement of $1,165,902,000. [8 TR 4273.]

Like Staff, Kroger, Energy Michigan, and ABATE, all recommend that the Commission order the deduction of revenue from *gross* energy sales net of fuel from total production costs as approved in cases U-18248 and U-18255.

On rebuttal, Kroger witness Justin Bieber recommended that the value of gross energy market sales to be excluded from the SRM capacity revenue requirement should be calculated based on updated revenues and costs in this instant case. (Bieber Rebuttal 4). Staff contends that doing so would not be possible unless an updated calculation was provided on the record with current costs using the same models used in the method that was approved by the Commission in cases U-18248 and U-18255. Absent this evidence, the Commission should continue to use the gross energy sales net of fuel amount it approved in these cases. The Commission should also require the Company to file updated amounts as described above using the most recent available numbers with its application in the Company's next general electric rate case.

Staff witness Gottschalk also testified against the subtraction the Company made of MISO Schedule 17 administrative costs from the projected energy sales revenue:

> The Company also inappropriately subtracted MISO Schedule 17 administrative costs from the projected energy sales revenue. There is absolutely no basis for this in the statute or in any previous cases deciding this issue, and the Company failed to support their inclusion, and therefore, their inclusion should be rejected. [8 TR 4272.]

No intervenors commented specifically on the MISO Schedule 17 admin costs. However, the inclusion of these costs by the Company is against the method approved by the Commission in previous cases and therefore, against the positions of Staff and Intervenors to continue using the method approved by the Commission in cases U-18248 and U-18255.

For the reasons detailed above, the Commission should reject the Company's proposed capacity cost calculation and approve Staff's.

D. The Commission should not issue a new capacity charge until the final order in this case.

The Company has proposed that the Commission review the capacity charge by December 1 and implement the new capacity charge on January 1, 2019. Staff does not believe a new capacity charge needs to be issued until the final order of this case. Staff witness Gottschalk testified:

> Although PA 341 Section 3 requires a contested case proceeding to determine the capacity charge by December 1 of each year, the

> Commission stated on page 71 of its November 21, 2017 Order in Case No. U-18248, "The Commission does not find, at this time, that the creation of a standalone proceeding is necessary. Among the options of general rate cases (which require a decision within ten months), PSCR plan cases, and PSCR reconciliations, the Commission believes that the annual review of the SRM charge required under Section 6w(5) will be accomplished for DTE electric." Section 6w(5) of 2016 PA 341 requires "Not less than once every year, the commission shall review or amend the capacity charge in all subsequent rate cases, power supply cost recovery cases, or separate proceedings established for that purpose." Furthermore, the Commission reviewed and updated the capacity charge in its April 27, 2018 Order in Case No. U-18255, which became effective for full service customers on May 1, 2018 and on June 1, 2018 for choice customers. Therefore, the Commission has already completed the required annual review for 2018 by December 1 and does not need to issue another capacity charge before the final order in U-20162, which will produce a capacity charge incorporating updated costs from this case. [8 TR 4272-4273.]

No intervenors took a position on this issue. The Commission should not issue an updated capacity charge until the final order in this case.

E. The Commission should make clear that the Residential Income Assistance (RIA) program is not designed on a certain level of funding.

When discussing the RIA program, the Company seems to imply the program is set to a certain level of money, and then the rate and number of customers in the program is determined by the total amount of money allocated to the program. (7 TR 3132.) This is a backwards view of how the program was designed. Staff witness Gottschalk testified:

> Staff takes issue with framing a change in the RIA as a "rate increase." This implies that the program is designed behind a certain amount of money. That is not the case. The program sets a certain number of customers likely to enroll in it for the test period based on historical data and a rate based on the residential customer charge. The amount of money credited to RIA customers is a result of those two factors. It

> is not the starting point for the program. In this manner, the RIA Credit is the same as any other rate and should not be referred to or treated differently. [8 TR 4273-4274.]

No intervenors took a position on this topic. As explained by witness Gottschalk, the Commission should explain that a level of money for the RIA program is not designated first. Rather, the number of customers in the program is estimated and a rate is established based on the residential customer charge. This produces the total amount of money being credited to RIA customers.

F. Electric Vehicle cost of service and rate design.

Staff agrees with the Company's proposed functionalization, assignment, and allocation of the electric vehicle pilot. (8 TR 4241.) Staff recommended reporting production benefits, tracking distribution system utilization, and corporate ownership of electric vehicles in DTEs service territory. (8 TR 4241-4242.) The Company agreed to the production and utilization reporting (8 TR 3622) but was silent on the fleet vehicle tracking. Staff further recommended the elimination of rate D1.9 Option 2 (8 TR 4242), and the Company agreed in rebuttal. (8 TR 3618.) Staff recommends the reporting of production benefits, distribution system utilization, and corporate ownership of electric vehicles in their EV report, as well as the elimination of rate D1.9 Option 2.

MEC/NRDC/SC/EIBC/IEI witness Jester proposes reducing or eliminating demand charges for fast charging of electric vehicles. (6 TR 2216-2217.) Staff witness Krause responded in rebuttal with clarification of what a "demand charge holiday" should look like:

> Staff would recommend that the Commission be specific about the holiday and not make it permanent. For example, the Commission could establish a DCFC tariff based on the underlying standard rate that has no demand charges for the next 2-5 years, and then for 2-5 years after increases demand charges until they reach parity with the D4 tariff. Staff does not support capping the demand charge ratio as suggested by the witness. [8 TR 4254-4255.]

Staff also pointed out that rate D3 is also used for fast charging and it has no demand charges. (8 TR 4255.) The Company made the same point in its rebuttal. (8 TR 3623-3624.) Additionally, MEC/NRDC/SC/EIBC/IEI witness Jester proposes a parking lot tariff for electric vehicles. (6 TR 2221-2222.) Staff witness Krause described the proposal as vague and premature. (8 TR 4256.) Staff recommends that all of these tariff proposals be rejected as premature for now, as the pilot has not yet even begun, and no data is available to gauge effectiveness of the current proposal. However, if the Commission were to consider a "demand charge holiday", Staff recommends that it be approved in accordance with Staff's rebuttal testimony.

Lastly, witness Jester proposes that the cost of fast charging should be less than the equivalent cost of gasoline. (6 TR 2218.) MEC/NRDC/SC/EC Witness Baumhefner supports the same general idea. (6 TR 2572-2573.) Staff witness Krause responds in rebuttal that keeping the price of fast charging less than the price of gasoline will result in incorrect price signals for fast charging in relation to Level 1 and Level 2 charging. (8 TR 4255-4256.) Chargepoint witness Ellis also opposes tying fast charging prices to the price of gasoline. (7 TR 3067-3069.) Staff recommends that tying fast charging rates to the price of gasoline be rejected.

G. Staff accepts the Company's residential distribution rate design with some exceptions.

Staff and the Company followed the same rate design methodology for residential distribution rates, including continuing to bring residential distribution rates toward parity while limiting the impact to any individual distribution rate to 20%. (8 TR 4282.) There was no controversy regarding this methodology, therefore the Commission should approve it. Staff did not agree with the Company's residential rate design regarding the proposed service charge increase. Regarding residential service charges, Company witness P.W. Dennis testified that, even though fixed distribution costs that do not vary with energy (kWh) consumption support a charge of over $45 per customer per month, in the interest of gradualism the Company is proposing a $9 residential service charge in this case. (8 TR 3868.) Staff, however, is recommending no change in the residential service charge. (8 TR 4282.) Support for Staff's residential service charge proposal is detailed further in section IX.B above.

H. Staff supports the Company's commercial and industrial distribution rate design method with some exceptions.

Staff designed rates to collect the proposed revenue requirement by class based upon Staff's cost of service study. Generally, Staff agrees with the Company's rate design method, which is based on the rate design previously approved by the Commission in MPSC Case No. U-18255. (8 TR 4284). The rate design continues to entail moving commercial secondary rates toward one unified distribution rate, while limiting the resulting increase to 10% in this case for any particular rate schedule. (8 TR 4284). Staff did not agree with the Company's commercial rate design in regard to increasing the service charge for rates which are not for supplemental service: Rates D1.8, D3, D3.2, D3.3, D4, and R8 separately metered. The Company proposed to increase the service charge for these rate schedules to $15 per month and Company witness K. A. Holmes testifies that commercial customer related costs from Company witness T. W. Lacey's cost of service study supports a charge of $175 per customer per month. (5 TR 1430.) Staff is recommending that the service charges for these customers remain at their current levels based upon Staff's cost of service study. (8 TR 4285.) Support for Staff's position on the commercial service charge is detailed further in section VII.B above.

I. Staff has several recommendations and modifications to the Company's proposed Distributed Generation (DG) tariff.

Staff's recommendations for the DG tariff are detailed below.

1. The Commission should not approve DTE's proposal to limit the existing Standard Contract Rider No. DG to non-renewable types of generation and should rename the tariff Distributed Generation Rider No. 14.

Company witness Philip W. Dennis testified that the Company is proposing to limit the applicability of its existing Standard Contract Rider No. DG tariff (this tariff is unrelated to the Company's proposed Standard Contract Rider No. 18 (Rider 18) to non-renewable types of generation. (8 TR 3878-2879.) However, Staff witness Julie Baldwin described the availability and potential benefit of the existing Standard Contract Rider No. DG tariff in her direct testimony:

> Rider DG is "[a]vailable to customers with on-site distributed generation desiring to operate in parallel with the Company's system and take service for their supplemental needs under one of the applicable tariffs listed above." (Residential, General, and Large General Service Rates) The tariff is applicable to projects with generation capacity no greater than 100 kW. Rider DG does not limit the size of the generator to the customer's annual energy consumption. Rider DG may allow a customer the opportunity to have an on-site project which would not otherwise fit under the requirements of the new proposed DG Rider 18. [8 TR 4175-4176.]

The reason provided by Mr. Dennis for limiting the applicability to Rider DG to non-renewable types of generation is that, in accordance with Acts 341 and 342 and the Commission Order in MPSC Case No. U-18383, the Company already has the net metering tariff—Rider 16 and the proposed Rider 18. Standard Contract Rider No. DG is applicable to the Residential Service Rate, Generate Service Rate, and Large General Service Rate. The tariff limits the size of the generation capacity to no greater than 100 kW and is available to "Distributed generation resources include reciprocating engine generator sets, small turbine-generators, fuel cells, regenerative dynamometers and renewable resources." Generally, the Sell-Back Energy Rate is the Company's monthly average top incremental cost of power. (Exhibit A-16, Schedule F10.) The six customers Mr. Dennis references (8 TR 3887) who are taking service under the existing Standard Contract Rider No. DG tariff appear to have shown a preference for staying on the tariff by not switching to Net Metering—Rider 16.

In his rebuttal testimony, Mr. Dennis agrees that there is no prohibition against additional tariff offerings for distributed generation. (8 TR 3886.) However, Mr. Dennis points out that Public Act 342 limits the capacity that can participate in the distributed generation program to 1% of the average in-state peak load for the preceding 5 years and raises the concern that "[i]f the Company is forced to also provide additional renewable energy distributed generation tariffs, any distributed generation capacity signing up for the alternative tariffs should be taken into account when determining if the Company has reached this limit." (8 TR 3386-3887.) Staff disagrees with the Company that the distributed generation capacity taking service under the existing Standard Contract Rider No. DG should be added to the Rider 18 distributed generation program. The Rider 18 program is a separate program with its own terms and conditions as specified in 2016 Public Acts 341 and 342. There is no legal basis for adding the capacity participating in the two programs together and applying the program size cap of Rider 18.

Ms. Baldwin also pointed out in her testimony that the Company may want to consider renaming the Standard Contract Rider No. DG due to potential confusion with the Company's proposed Rider 18. (8 TR 4176.) In rebuttal, Mr. Dennis suggested renaming the tariff "Rider 14." (8 TR 3887.) Staff supports the Company's proposal.

2. The Commission should approve Staff's recommended modifications to DTE's proposed Standard Contract Rider No. 18—Distributed Generation Program (Rider 18) as described below.

Staff witness Baldwin recommended six modifications to Rider 18 which are reflected on Staff Exhibit S-11.0 and described separately below.

a. Duplicate phrase "and metered at a single point of contact."

Ms. Baldwin testified that the phrase "and metered at a single point of contact" is duplicated in numbered paragraph (1), (2), and (3) on Rider 18 (Original Sheet Nos. D-111.00 and D- 112.0) and recommended deleting the second reference in each numbered paragraph. (8 TR 4171-4172.) The Company agreed with Staff's recommended revisions and pointed out that the duplication only occurred in paragraphs (2) and (3). (8 TR 3900.) Staff agrees with the Company's proposal to remedy the duplications in paragraphs (2) and (3).

b. The Outflow Credit should be applied to the entire bill.

Ms. Baldwin pointed out in her testimony that the Commission addressed the matter of applying accumulated credits against future bills in its April 18, 2018 Order in Case No. U-18383:

> Under any reasonable interpretation, the transmission and distribution exclusion cannot refer to the level of accrued credits that can be applied to the customer bill for the following billing period since subsection (4) expressly allows the offset of the total power supply charges (which include transmission charges). [U-18383, April 18, 2018, page 14.]

Staff continues to support this position and notes that further discussion can be found in Section VI.A.3(a) and (b) of this brief.

c. The Outflow Credit should be based on the methodology proposed by Staff in its distributed generation tariff recommendations.

Staff provides a detailed discussion of Staff's recommended methodology for calculating the outflow credit in Section VI.A.3(a) and (b) of this brief.

d. The System Access Contribution charge should be rejected and removed from the tariff.

A detailed discussion of Staff System Access Contribution position is provided above in Section VI.A.2 of this brief.

e. The tariff provision providing for any existing Outflow Credit to be forfeited upon termination from the DG Program should be revised to provide for the credit to be applied to the customer's bill or refunded.

In the Company's proposed DG Rider 18 it proposes that any remaining Outflow Credit in a customer's account must be forfeited upon termination from the DG Program found in Exhibit A-16, Schedule F10, Original Sheet No. D-116.00. Staff's Exhibit S-11.1, which is an audit response provided to Staff explains that the basis for the Company including this provision is the Company's interpretation of Section 177(4) of 2016 Public Act 342 that Outflow Credits cannot be applied against distribution and transmission charges. However, the Staff again points out that the Commission has already addressed this matter in its April 18, 2018 Order in MPSC Case No. U-18383. The limitation against applying the outflow credit to distribution and transmission charges only for the portion of outflow that exceeds inflow in the modified net metering construct. (Order, p 14.) Therefore, Staff recommends that such Outflow Credits be credited to the customer's account or refunded to the customer in the event of termination from the program.

f. DTE's annual reporting to the Commission should include information about interconnection costs paid by Category 1 DG customers.

2016 PA 342 includes a provision in Section 175(1) which states, "The customer shall pay all interconnection costs." [MCL 460.1175(1).] This provision was not part of the existing net metering program for Category 1 (primarily residential) customers. Staff's Exhibit S-11.2 is an audit response from the Company describing the types of costs Rider 18 customers could experience including service transformer and secondary line conductor upgrades. Since these are new costs for customers, Staff proposes that the Company's annual DG Program report include the costs and a description of the interconnection equipment provided for each customer. (8 TR 4175.) Ms. Baldwin explained that this information has value so that solar installers and potential Rider 18 customers are aware of such costs. *Id.* Ms. Baldwin proposed language for inclusion on S-11.0 to modify the reporting provision on the rider to reflect this information. *Id.* That language, in bold font and underlined, states:

> **DISTRIBUTED GENERATION PROGRAM STATUS AND EVALUATION REPORTS**
>
> The Company will submit an annual status report to the Commission Staff by March 31 of each year including Distributed Generation Program data for the previous 12 months, ending December 31. **The report will include interconnection costs paid by each customer and the interconnection equipment provided by the**

> **<u>Company during the reporting year.</u>** The Company's status report shall maintain customer confidentiality.

Company witness Richard J. Mueller testified that it is unclear whether Staff's request is applicable to both Category 1 and 2 projects and that the "…newly proposed reporting of cost and equipment at a customer specific level is unprecedented." (8 TR 3798.) Staff clarifies that the request refers to only Category 1 customers.

Based on the Company's discovery responses as shown in the ELPC's Exhibits ELP-4, ELP-23, ELP-24, ELP-25, ELP-26, ELP-27, ELP-28, and ELP-29, the Company does not specifically track utility-owned infrastructure for distributed generation customers. Now that the law has changed and Category 1 customers will be responsible for paying for these costs, it is highly important that the nature of these costs are made publicly available. Since billing for these Category 1 upgrades is a new activity, and these upgrades are not currently prominent enough for the Company to track, Staff maintains the position that providing cost and equipment descriptions for each occurrence would not be overly burdensome. However, to allay the Company's concerns about this reporting request, Staff recommends that the Commission direct the Company and Staff to work together to develop an appropriate and reasonable reporting template for the Company to use for the 2019 annual DG report to be submitted on March 31, 2020.

g. The Commission should clarify that if a customer expands their system before Public Act 342 went into effect on April 20, 2017, the customer's entire project will be grandfathered into the net metering program for an additional 10 years.

Staff witness Baldwin recommended that the Commission provide clarity in regard to the 10-year grandfathering time period for the situation where a customer has an existing project taking service under Standard Contract Rider No. 16—Net Metering and expands their system prior to the new DG tariff taking effect. She recommended that the 10-year grandfathering time period restart with the addition of the expanded generation. (8 TR 4176-4177.) Ms. Baldwin pointed out that this situation would have limited applicability due to timing, the number of customers with existing net metering systems and the limitation in the law that systems can be no larger than a customer's annual usage. However, on rebuttal, Company witness Dennis disagreed with Ms. Baldwin's recommendation. (8 TR 3901-3902.) Mr. Dennis explains that language in MCL 460.1183 states: "(1) A customer participating in a net metering program approved by the commission before the commission establishes a tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, may elect to continue to receive service under the terms and conditions of that program for up to years from the date of enrollment. (2) Subsection (1) does not apply to an increase in the generation capacity of the customer's eligible electric generator beyond the capacity on the effective date of this section." Based upon this provision, Mr. Dennis asserted that a Rider 16 customer should only be able to expand their generation and remain on Rider 16 if the expansion was done prior to Rider 18 going into effect. (8 TR 3902.) Upon careful consideration of this language in the law, Staff agrees with the Company that an expansion of generation capacity after April 20, 2017 cannot trigger a reset of the 10-year net metering grandfathering period.

h. The Commission should clarify that if a site with an existing net metering project is sold, the 10-year net metering program eligibility should not restart.

Ms. Baldwin proposed that the 10-year grandfathering time-period for taking service under Standard Contract Rider No. 16—Net Metering should be unaffected in the event a site with an existing net metering project is sold. (8 TR 4177.) Ms. Baldwin reasoned that because the new owner did not make the original capital investment to install the project, they should not receive the benefit of resetting the grandfathering provision for a new 10-year period if the site with the project was sold prior to Rider 18 going into effect. *Id.* No party rebutted this proposal. Staff continues to support this position.

i. The Commission should approve clarifying language on Standard Contract Rider No. 16—Net Metering.

The Company proposed adding the following language to its Standard Contract Rider No. 16—Net Metering tariff to clarify its applicability:

> This Rider is available only to customers on-site generation with an approved application prior to April ____, 2019.

Staff agrees with DTE that clarifying language is necessary, but Staff expressed concern with the use of the word "approved." (8 TR 4177.) The transition period in the Commission's April 18, 2018 Order in MPSC Case No. U-18383 does not refer to an "approved" application by the effective date of the new Rider 18 as a milestone. *Id*. Based on that order, Ms. Baldwin recommended the following language:

> This Rider is available only to customers participating in the program prior to April ____, 2019. [8 TR 4178.]

On rebuttal, Company witness Dennis agreed that the word "approved" originally proposed by the Company could be misinterpreted. (8 TR 3900.) Mr. Dennis further testified that the word proposed by Staff, "participating," could also be misinterpreted. *Id.* In order to have the smoothest transition to the new Rider 18 as possible, Staff and the Company both appear to agree that clarity is important. To further improve on the language, Mr. Dennis proposes the following sentence:

> This Rider is available only to customers with a completed application pending prior to April _____, 2019. (8 TR 3901.)

The timing of the Commission's order in this case will allow customers with incomplete applications pending before the Company to complete those applications and be considered "participating" in the program. While this opportunity is not captured by the Company's proposed language put forth in Mr. Dennis' rebuttal, Staff nonetheless supports approval of Mr. Dennis' language change to Rider 16. The new language succeeds in clarifying the applicability of Rider 16.

J. Staff does not support the Company's methodology to determine the power supply demand and energy voltage level discounts for rates D11 and D8.

Staff calculated power supply demand and energy voltage level discounts for rate schedules D11 and D8 in the same manner as approved by the Commission in the previous two rate cases, cases U-18014 and U-18255. (8 TR 4286.) For this method, the voltage level loss factor differentials for demand and energy are applied directly to the proposed demand and energy charges to produce the discounts. (8 TR 4286.) The initial Commission Order for the current method was given in case U-17767. It stated:

> The Commission agrees with the Staff, noting that in its initial brief, the Staff proposed, "to recalculate the existing discounts based on the appropriate loss factors, while still designing rates to collect the approved revenue requirement in total." Staff's initial brief, p. 75. Therefore, the Commission finds that ABATE's and DTE Electric's exceptions should be rejected, and the adjusted voltage level discounts, based on loss factors, shall be incorporated into rates as recommended by the Staff. [*In re DTE Electric Rate Case*, MPSC Case No. U-17767, 12/11/2015 Order, p 122.]

The Order in case U-18014 stated:

> [t]he Commission agrees that ABATE made the same recommendations regarding Rate D11 voltage level power supply charges in Case No. U-17767, which were reviewed and rejected by the Commission. The Commission finds the Staff's position persuasive and agrees with the ALJ that the Staff's method for determining voltage level power supply charges should be continued. The Commission also adopts the Staff's recommendation that the company file, in its next general rate case, a proposed demand charge voltage level discount for Rates D11 and D8, including the necessary billing determinants, including demand by voltage level. [*In re DTE Electric Rate Case*, MPSC Case No. U-18014, 1/31/2017 Order, p 114.]

Most recently, in case U-18255 the Commission stated:

> The Commission adopts the recommendation of the ALJ. ABATE provided convincing evidence that the differences in line losses (1.03 MW at the transmission level versus 1.09 MW at the primary level, to deliver 1.0 MW of demand) provide a rational basis for the discount. The Commission agrees with the Staff and ABATE that it is reasonable to adopt the same method for calculating both the demand and energy voltage level discounts, and that voltage level line loss differences provide an appropriate basis. Like the ALJ, the Commission finds that the Staff's proposal is consistent with the method approved in the 2017 order for determination of the rates themselves. The 2017 order, p. 114; 9 Tr 2254-2255, 2269. [*In re DTE Electric Rate Case*, MPSC Case NO. U-18255, 4/18/2018 Order, p 69.]

Instead of using the Commission approved method, the Company has again proposed to calculate the voltage level discounts using another method. For the Company's energy discount method, Rates D11 and D8 were treated as one class since both rates share the same energy rates, and loss adjusted sales are used to allocate energy revenue to each voltage level and then voltage level energy rates are calculated to determine the voltage level energy discounts. (5 TR 1224.) For the Company's billing demand voltage level discount, each rate's voltage level adjustment was determined separately due to differences in contribution to the 4CP. Demand revenue was allocated based on the voltage level 4CP and then divided by the voltage level billing demands to determine voltage level demand rates and voltage level adjustments. *Id.* For the Company's transmission voltage level demand adjustment, the same methodology is used as for the billing demand voltage level adjustments but using the 12CP method. (5 TR 1225.) Company witness Timothy A. Bloch submits that the approved method only considers loss differences between voltage levels but fails to consider the voltage level cost responsibility to which the losses are applied. This creates intra-class subsidies between voltage levels. *Id.*

ABATE witness Brian C. Andrews recommends that the energy and demand voltage level discount methodology previously approved by the Commission in Case U-18255 continue to be utilized. (7 TR 2849.) ABATE argues that the procedure that the Company has proposed is significantly flawed and does not determine rates that are based on cost-causation principles. *Id.* ABATE provides the results of the Company's proposal as evidence. For example, under the Company's proposal, the discount for capacity demand for the subtransmission customer is $1.97/kW, but for transmission customers, the discount is only $0.95/kW. For non-capacity demand discounts, subtransmission gets a $0.11/kW discount while transmission customers are being assessed a surcharge of $0.25/kW. ABATE reasons that the Company's method is clearly flawed because transmission level customers utilize less infrastructure and create fewer losses than subtransmission customers, therefore, it is less expensive to provide service to transmission customers and they should pay lower rates. (7 TR 2850-2851.) Finally, ABATE submits that neither they nor the Company is aware of any example where an electric utility charges a higher transmission voltage demand rate than customers served at lower voltages for firm service. (7 TR 2852.)

On rebuttal, Company witness Bloch again insists that the Commission approved method is not cost based and produces demand voltage level discounts that increase intra-class subsidies between voltage levels. (5 TR 1257.) He states that, "[t]o determine demand voltage level discounts without accounting for voltage level cost differences, which are known values and significantly affect the outcome, does not follow cost of service principles." (5 TR 1257.) He also counters ABATE's claim that the Company was not aware of another electric utility that charges a higher transmission voltage demand rate than the lower voltage customers for firm service. Witness Bloch's rebuttal testimony indicates that the Company provided ABATE with Consumers Energy's GPD tariff, which provides a substation ownership credit of $0.65/kW to Level 2 customers (subtransmission) and a $0.38/kW credit for Level 1 customers (transmission). (5 TR 1259.) However, the Consumers Energy Rate GPD example provided by the Company does not provide an overall demand rate for subtransmission customers that is lower than the overall demand rate for transmission customers such as occurs in the Company's current rate case. This seems to support the position that it costs more to own a substation for subtransmission voltage than for transmission voltage.

The Company has not provided enough new evidence in this case to justify their voltage level discount proposal and presents arguments similar to those rejected by the Commission in the Company's previous general electric rate case. For the reason stated above, the Commission should again approve Staff's method for calculating the power supply demand and energy voltage level discounts for rates D11 and D8.

K. Staff does not support the Company's proposal to increase the returned check charge to the maximum allowed by the State of Michigan.

Staff's position is that the returned check charge should remain at its current level of $15.00. The Company has proposed to increase the charge to $28.66, the maximum amount allowed by the State of Michigan, as part of a plan to fund a third-party vendor who will be hired to implement an algorithm used to reduce insufficient fund payments. However, the Company did not provide the necessary cost analysis to support such an increase or how much costs would need to be recovered through the returned check charge to fund the third-party vendor. (8 TR 4287.) In addition, customers assessed this charge are often those who do not have an abundance of resources and cannot easily absorb such an increase. Therefore, due to the lack of proper cost justification and impact such an increase would have on customers, the current charge of $15.00 should be retained. Staff, however, does not oppose the Company's proposal to hire a third-party vendor to assist in reducing insufficient fund payments.

L. For Standby Tariff, Rider 3, the Commission should utilize the same rate design methodology as in the Company's last electric rate case.

The Commission should calculate Standby Rates in the same manner as ordered in U-18255. The Company proposes changing the production allocator for Rider 3. (5 TR 1231-1237.) The Company also proposes changing the way the generation reservation fee is calculated. (5 TR 1238-1239.) In direct testimony, Staff recommends no changes from the previous order (8 TR 4242-4243) and points out that the decisions in that case were in harmony with Staff's Standby Rate Working Group report. ABATE witness Dauphinais discusses at length the production allocator and generation reservation charge for Rider 3. (6 TR 1750-1756.) Mr. Dauphinais comes to the same conclusion that no changes should be made from the order in the previous case. (6 TR 1756.) In rebuttal testimony, the Company continues to support the positions it filed initially. (5 TR 1246-1256.) Staff maintains that there has not been sufficient experience with the changes incorporated into Rider 3 in Case No. U-18255 to recommend changes in the instant case.

EIBC witness Scripps makes several arguments for standby customers and partial usage of the distribution system. (8 TR 3480-3484.) In rebuttal testimony, Staff witness Krause describes how distribution use is measured for the purposes of cost allocation and rate design. (8 TR 4257-4258.) EIBC witness Jester suggests linking distribution capacity to generator outage rates. (6 TR 2225-2227.) In rebuttal testimony, Staff witness Krause describes the differences between distribution capacity and generation capacity and recommends that witness Jester's proposal be rejected:

> Generation tends to be centralized, so when not being used by one customer it can be readily used by another customer, even one a long distance away in the service territory. Distribution capacity tends to be much more localized. When local distribution capacity is not used by one customer it may be usable by another customer nearby on the same circuit but is clearly not usable by someone a long distance away in the service territory. While further up the system, this becomes somewhat less true, there are still geographic constraints on use of the system.

* * *

> This means that methods of pro-ration that may be appropriate for generation capacity are not appropriate for distribution capacity. Using generator outage rates to determine charges for generation capacity is appropriate and reasonable, and using generator outage rates to determine charges for distribution capacity is inappropriate and unreasonable. [8 TR 4258.]

The definition of partial use of the distribution system advocated for by EIBC for Rider 3 customers was rejected in Case No. U-18255 and should be rejected again. The tying of distribution capacity to generator outage rates should likewise be rejected. For these reasons, Staff maintains that the ALJ should recommend, and the Commission should approve, a rate design for Rider 3 using the same method as approved in the previous case.

M. Retail Access Service Rider (RASR) Modifications

DTE witness Bloch proposes changes to standardize the Return to Full Service provisions in DTE's RASR tariff, citing that the basis for the original establishment of the provisions have since changed. (5 TR 1228-1232.)

Energy Michigan witness Zakem recommends additional RASR tariff modifications. Specifically, Mr. Zakem recommends that the Commission retain the two options under the current Section E4.3.B for (i) Option 1—12 Month return to Service Commitment and (ii) Option 2—Short Term Service. (7 TR 3092). Mr. Zakem claims that retaining these two options will retain flexibility for the customer and protect the utility from "gaming" of energy costs by customers switching suppliers. (7 TR 3091.) Staff does not oppose retaining these two options, however, based on Michigan's current electric choice program structure, Staff disagrees with Mr. Zakem's position that Michigan's current electric choice market structure allows for "short stays by Electric Choice customers who return to full service,". *Id.* Given the current waitlist of customers in DTE's queue, it seems implausible for an electric choice customer to return to full service for a "short stay" with DTE Electric before again taking service through an AES, and unlikely that these tariff provisions would be used anytime soon. (8 TR 4224-4225.)

Additionally, Mr. Zakem proposes modifications to clarify certain language relating to the responsibilities of DTE to provide metered data to both the customer and/or the customer's designated supplier. (7 TR 3094.) Staff does not oppose the tariff changes outlined in Exhibit EM-5 (AJZ-5). Staff is supportive of clarifying tariff language and streamlining procedures for the betterment of the program and all parties involved and believes it is reasonable for suppliers to request that data needed for billing be issued in a timely and accurate manner. However, Staff would like to note for the record that the process of providing meter data to a DTE electric customer and/or the customer's designated supplier is not something that Commission Staff is typically privy to. (8 TR 4226.)

Lastly, Staff recommends that the Commission direct DTE to update its RASR tariff in this proceeding to remove a specific date referenced in Sheet E6.00, Section E2.6.1 (C). Staff's proposed modification allows this language to continually be precise regardless of any updated electric choice procedures that may be approved going forward. (8 TR 4227.)

N. The Commission should deny the Company's requested pilot rates or approve them with significant changes.

The Company proposed two new pilot residential rates for various reasons: Weekend Flex and Fixed Bill. (6 TR 2088-2104.) Staff opposes both pilots in total as flawed and counter-productive. In addition, Staff opposes particulars of each program as flawed.

Both of the Company's proposed pilots severely dilute the proper price signals and would lead to inefficient usage. (8 TR 4298.) The Company claims that such a conclusion is speculative, as it cannot be determined until the pilots are run. (6 TR 2112.) Luckily, it is possible to reach a reasonable projection of customer behavior using simple economic principles. Lower prices lead to increased demand. A fixed price for a service tends to increase use of said service over what it would have been if it were charged by use. For example, people tend to eat more at an all-you-can eat buffet than if they had to pay for items individually. Data and studies are not necessary to accept that these principles generally apply. If it were necessary to reprove basic economic principles in every instance their use was required, the evidentiary record in general rate cases (where prices are set for regulated monopolies to substitute for the discipline of the market) would become prohibitively distended. The Company claims that the pilots include a "long-term conservation signal". (6 TR 2093, 2100.) This is incorrect. The claimed "long-term conservation signal" is merely the fact that future 12 month offers will be adjusted based on the previous 12 months' usage, which does not fix the price signal dilution and will likely lead to inefficient usage. (8 TR 4299.) The Company also claims that usage alerts, potential future offer prices, and the presence the reasonable usage clause prevent the dilution of the price signal. (6 TR 2112-2113.) This is also incorrect. All these things do is attempt to mitigate the fact that the price signal is now incentivizing inefficient usage. A better result can be achieved by sending the correct price signal in the first place. Additionally, Staff takes issue with the reasonable usage clause. The reasonable usage clause "would result in exactly the behavior Staff is concerned about due to the dilution of price signals, which would then require the customer to pay what they would have paid had the correct price signals been sent in the first place." (8 TR 4299.) Should the Commission decide to approve the pilots, Staff recommends that the reasonable usage clause not be approved. *Id.* If the Commission determines that a reasonable usage clause is appropriate, it should not include the provision that requires customers to pay what they would have paid had they been charged correctly to begin with. *Id.* The Company argues that eliminating the reasonable usage clause makes inefficient use more likely. (6 TR 2115.) In fact, it is the design of the pilots themselves that do this, as described above. It makes little sense to set up a structure incentivizing something and then punish it, when not setting up the structure in the first place would have had a better result. Staff also opposes the automatic reenrollment of customers into either pilot, recommending that reenrollment require a proactive request from customers. (8 TR 4299.) The Company disagrees, claiming a lack of supporting evidence from Staff. (6 TR 2113.) No supporting evidence is necessary to support Staff's policy position that, if these pilots were approved, customers should be required to actively desire continued participation rather than it being the default.

The Company cites customer interest as a factor in proposing the pilots, finding the number of customers who are interested or would enroll compelling. (6 TR 2090, 2097, 2116-2117.) The very limited 6% and 11% of customers interested in the pilots does not justify the elimination of price signals or the resulting potential for inefficient use. (8 TR 4298-4299.) In addition, based on the wording of the testimony describing the questions and responses from the survey, Staff is concerned acquiescence bias may have played a significant part in the results. For future surveys used to justify novel pricing, Staff recommends the Commission require the Company to avoid acquiescence bias through proper survey design and prove that they have done so as part of filings and supporting documents.

For the reasons above, the ALJ should not recommend approval of the Company's proposed Weekend Flex and Fixed Bill pilots, nor should the Commission approve them. Should the Commission determine that approval is desirable, the pilots should be modified by removing the automatic reenrollment and reasonable usage clauses, or at the very least remove the requirement that customers pay what they would have paid on the standard rate if removed from the pilots under said clauses.

O. The Company's proposed Summer On-Peak Rate and alternative transition plan should be approved over the Company's objections.

While the Company proposed a summer on-peak rate as required by the Commission in its order in the Company's previous general electric rate case, the Company requested that the rate not be approved by the Commission in the instant case. (3 TR 85.) Staff disagrees. As noted by the Company, the Company's arguments for not approving the summer on-peak structure are the same as those recently rejected by the Commission. *Id.* The Commission should again reject these arguments and approve the Company's proposed summer on-peak rate with modifications described below.

The Company's proposed summer on-peak rate structure includes defining the on-peak time period as 4:00 P.M. to 9:00 P.M., Monday through Friday in the months of June through September. (5 TR 1343-1344; 8 TR 3863.) Staff agrees with this on-peak period. The Company's proposed summer on-peak rate structure bases the differential between the summer on-peak rate and the rate for all other hours on the LMP differential between summer on-peak hours and summer off-peak hours. (5 TR 1344.) Staff disagrees with this differential. As the rates apply to the summer on-peak period and all other hours, the differential in LMPs between these periods is what is appropriate to use. (8 TR 4301-4302.) Staff also recommends that the differential be applied as a percentage rather than a nominal difference, as the nominal differences between wholesale and retail prices make a percentage more appropriate. (8 TR 4302.) The Company disagrees, stating that the resulting price differential is higher than the LMP differential and is therefore inappropriate.

(8 TR 3883-3884.) Again, the differential is only higher in nominal terms; given the difference between the retail and wholesale rates at the nominal level, a percentage more accurately depicts the appropriate differential. The Company's proposal maintains the current rate structure for capacity rates. This is inappropriate. It is appropriate to charge more during summer on-peak hours for capacity, as this is when the capacity need is set. (8 TR 4302.) This proposal is also consistent with the Staff and Company proposals in U-20134, Consumers Energy's pending general electric rate case. (8 TR 4302, 8 TR 3885-3886.) The Company disagrees with Staff's proposal, stating the Commission's prior order did not include such a requirement. (8 TR 3882-3883.) This has no bearing on the appropriateness of the change. The Company also claims that the Consumers Energy case is distinguishable by the fact that Consumers proposed the differential applying to both capacity and non-capacity charges and reflected projected shifts in usage between time periods. (8 TR 3885-3886.) As noted by several Company witnesses in this case, it is unnecessary to adjust usage projections in this case, as the rate will take effect outside of the test year. (5 TR 1344, 8 TR 3865.) Therefore, this argument must be rejected. Staff does provide an alternative, however— that the capacity charge be moved to a uniform rate for all kWh. (8 TR 4302.) The Company does not oppose the alternative proposal, other than to state the reason for it is unclear. (8 TR 3883.)

Staff recommends a modification to the Company's summer on-peak rate transition plan, as the initial plan was too aggressive to allow for appropriate time to integrate the new rate into the Company's systems. (8 TR 4300-4301.) Staff received two proposed updated plans from the Company through audit; the recommended plan and the alternative plan. *Id.* The main difference between the two plans is a later implementation date in the recommended plan to allow for testing different rate designs. (8 TR 4301.) Staff recommends that the alternative plan be approved, as the Company's proposed rate design is appropriate, and there is therefore no need to test alternative designs. *Id.* The Company attempts to justify the recommended plan by lumping in other potential rate design examinations unrelated to the summer on-peak transition. (3 TR 102-103.) These other rate design examinations are unrelated to the summer on-peak transition, can take place any time, and should therefore not be used to justify putting of the transition more than is required to prepare the underlying technical support.

For all of the reasons discussed above, the ALJ should recommend, and the Commission should approve, the alternative transition plan to summer on-peak rates. Those rates should be designed with the Company's proposed on-peak period, differentials between the summer on-peak rate and the rate for all other hours based on the percentage LMP differential for those hours. This differential should also be applied to capacity rates. In the alternative, the capacity rates should be uniform for all hours of the year.

P. The maximum number of events under Rate D1.8 should be decreased to 14.

Staff proposed lowering the maximum number of events allowed to be called on Rate D1.8 from 20 to 14, bringing the Company's number of events to parity with Consumers Energy's comparable rate and potentially increasing marketability. (8 TR 4303.) The Company agrees with this change, and no party opposes it. (3 TR 384.) Therefore, the modification should be approved.

X. Miscellaneous Issues

A. The Commission should reject the Company's proposed IRM.

The Commission should not approve the DTE Electric's proposed Investment Recovery Mechanism (IRM) at this time. DTE Electric is proposing to recover the incremental revenue requirement associated with certain distribution, fossil generation and nuclear generation capital expenditures through 2022 with an IRM. The Company believes but does not guarantee that they may be able to defer filing for a rate increase until sometime in 2022 for new base rates in 2023, if they receive the IRM as proposed. (8 TR 4161.) The Company is requesting recovery of approximately $2.8 billion in capital expenditures from April 1, 2020 until December 31, 2022. Also, the Company is proposing the IRM underspending be reconciled. *Id*. Staff provided testimony stating the scope of the proposed IRM exceeds investments for compliance and safety and needs to be approached in a more cautious manner, to ensure all potential benefits are realized. (8 TR 4163.) Staff proposes the use of performance measurements with an IRM with this type of spending as outlined in the Staff's framework for five-year distribution plans provided in Commission Docket U-20147. *Id.* In the docket, the use of performance measurements as well as economic incentives and disincentives should be used with large scale IRM's. *Id.* Staff testified that it would like to see clear public policy and performance goals at the onset of the investment necessary for an IRM. In addition, Staff testified that is was not clear what value (improved customer service, improved customer satisfaction, improved reliability, etc.) will be returned if the Commission was to approve the IRM. *Id.* But that rate payers would have guaranteed rate increases during the IRM period.

Staff believes the use of performance metrics and performance-based ratemaking will also be beneficial as it will reduce the regulatory burden because it will allow Staff and Intervenors to focus prudency reviews on outcomes in key customer focused performance areas, rather than spending plans and specific costs incurred during the IRM. *Id.* Although the Company claims the proposed IRM will also minimize regulatory burden, without a clear commitment to not file a base rate case during the IRM, there could be an IRM reconciliations and base rate cases going on concurrently in the future. *Id.* This would result in a significantly increased burden to all interested parties. Staff concluded its testimony by stating that it is not recommending Performance Based Rates (PBR) in this case as it has previously recommended in Commission Docket U-20147 that the Commission create a collaborative to facilitate the financial and regulatory implications of an IRP outside of a rate case to lead to a framework for PBR that better reflects the goals and objectives of the Commission. (8TR 4164.) Therefore, Staff recommends the Commission not approve the IRM as proposed by the Company.

XI. Conclusion

Staff recommends that the ALJ and Commission find that DTE Electric's total revenue deficiency will be $135,160 million in the projected test year. Staff recommends that the ALJ and Commission adopt Staff's lower rate base, return on equity and operating expenses, as well as Staff's proposed cost of service, rate design and tariff revisions. Staff's recommendations strike the right balance between DTE Electric's interests and its ratepayers' interests.

Respectfully submitted,

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

Amit T. Singh (P75492)
Spencer A. Sattler (P70524)
Daniel E. Sonneveldt (P58222)
Assistant Attorneys General
Public Service Division
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917
Telephone: (517) 284-8140

DATED: January 11, 2019

APPENDIX A

Michigan Public Service Commission **Appendix A**
DTE Electric Company Staff Initial Brief
Projected Revenue Deficiency (Sufficiency) Case No.: U-20162
Projected 12 Month Period Ending April 30, 2020
($000)

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**Company Projection**	**Staff Adjustment**	**Staff Projection**
1	Rate Base	Exh. A-12, Sch. B1	17,172,558	(121,234)	17,051,324
2	Adjusted Net Operating Income	Exh. A-13, Sch. C1	750,856	79,012	829,868
3	Overall Rate of Return	Line 2 ÷ Line 1	4.37%	0.49%	4.87%
4	Projected Rate of Return	Exh. A-14, Sch. D1	5.76%	-0.31%	5.45%
5	Income Requirements	Line 1 x Line 4	988,985	(60,305)	928,680
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	238,129	(139,317)	98,812
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	1.3496	-	1.3496
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	321,387	(188,027)	133,360
9	Revenue Deficiency / (Sufficiency)-Tree Trim Surge	Staff Witness Evans	7,053	(7,053)	-
10	Revenue Deficiency / (Sufficiency)-Total	Line 8 + Line 9	328,440	(195,080)	133,360
11	U-20105 TCJA Rate Impact with New Rates Effective in the Instant Case	Staff Witness Pung			148,237
12	Net Rate Increase	Line 10 + Line 11			$ 281,597

APPENDIX B

Michigan Public Service Commission | **Appendix B**
DTE Electric Company | Staff Initial Brief
Projected Rate Base | Case No.: U-20162
Projected Average Balances Period Ending April 30, 2020
($000)

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**Company Projection**	**Staff Adjustments**	**Staff Projection**
1	Utility Plant in Service:				
2	Plant in Service	Exh. A-12, Sch. B2, L6	21,317,591	(108,368)	21,209,223
3	Plant Held for Future Use	Exh. A-12, Sch. B2, L7	57,923	-	57,923
4	Construction Work in Progress	Exh. A-12, Sch. B2, L8	1,679,418	-	1,679,418
5	Acquisition Adjustments	Exh. A-12, Sch. B2, L9	116,148	-	116,148
6	Total Utility Plant	Sum Lines 2 thru 5	23,171,079	(108,368)	23,062,711
7	Depreciation Reserve	Exh. A-12, Sch. B3, L6	(7,639,577)	37,720	(7,601,857)
8	Net Utility Plant	Line 6 + Line 7	15,531,502	(70,648)	15,460,854
9	Net Capital Lease Property	Exh. A-12, Sch. B4.1, col. (c), L10	6,222	-	6,222
10	Net Nuclear Fuel Property	Exh. A-12, Sch. B4.1, col. (c), L11	112,164	-	112,164
11	Total Utility Property and Plant	Sum Lines 8 thru 10	15,649,888	(70,648)	15,579,240
12	Less: Capital Lease Obligations	Exh. A-12, Sch. B4.1, col. (c), L68 + L80	6,324	-	6,324
13	Net Plant	Line 11 - Line 12	15,643,564	(70,648)	15,572,916
14	Allowance for Working Capital	Exh.A-12, Sch. B4	1,528,994	(50,586)	1,478,408
15	Total Rate Base	Line 13 + Line 14	17,172,558	(121,234)	17,051,324

APPENDIX C

MICHIGAN PUBLIC SERVICE COMMISSION

Appendix C
Staff Initial Brief
Case No.: U-20162

DTE Electric Energy Company
Projected Net Operating Income
for the Test Year Ended April 30, 2020
($000)

		Revenue				Expenses								NOI			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Line No.	Description (Witness)	Sales Revenue	Base Fuel & Purchase Power Rev.	Other Revenue and R2	Total	Fuel and Purchased Power	Other O&M Expense	Depreciation & Amort.	Property Taxes	Other Taxes	State & Local Income	FIT	Other Utility (Income) / Deductions	Total	NOI	AFUDC	Other Operating Income Adj.	Adjusted NOI
	Company Filed																	
1	Operating Income	3,309,210	1,385,795	90,345	4,785,349	1,385,795	1,312,396	948,986	275,525	52,234	42,543	44,936	2,134	4,064,549	720,800	32,973	(2,917)	750,856
	Staff Adjustments																	
2	Inflation (Welke)				-		(12,338)				766	2,430		(9,141)	9,141			9,141
3					-						-	-		-	-			-
4	Injuries and Damages (Welke)				-		(892)				55	176		(661)	661			661
5	Incentive Compensation (McMillan-Sepkoski)				-		(27,083)				1,682	5,334		(20,067)	20,067			20,067
6	Uncollectibles (Welke)				-		(234)				15	46		(173)	173			173
7	Active Healthcare Credit Amortization (Welke)				-		(1,733)				108	341		(1,284)	1,284			1,284
8	Incremental Charge Forward O&M (Ozar)				-		(1,168)				73	230		(865)	865			865
9	Meter Reading (Matthews)				-		(2,147)				133	423		(1,591)	1,591			1,591
10	Tree Trimming O&M Expense (Evans)				-		13,007				(808)	(2,562)		9,637	(9,637)			(9,637)
11	Sales Revenue - RIA Customers	900			900						56	177		233	667			667
12	AFUDC Adjustment (Gerken)				-						-	-		-	-	1,923		1,923
13	Depreciation Rate Adjustment (Edelyn)				-			(65,238)			4,051	12,849		(48,338)	48,338			48,338
14	Cap Ex. Adj. Impact on Depreciation Expense				-			(6,233)			387	1,228		(4,618)	4,618			4,618
15	Excess DFIT Amortization Adj. (Nichols)				-						-	(411)		(411)	411			411
16	Proforma Interest (Nichols)				-						261	828		1,089	(1,089)			(1,089)
17	Interest Synchronization (Nichols)	-	-	-	-	-	-	-	-	-	0	1	-	1	(1)	-	-	(1)
18	**Total Adjustments**	900	-	-	900	-	(32,587)	(71,471)	-	-	6,779	21,090	-	(76,189)	77,089	1,923	-	79,012
19	**Staff NOI - Test Year**	3,310,110	1,385,795	90,345	4,786,249	1,385,795	1,279,809	877,515	275,525	52,234	49,322	66,026	2,134	3,988,360	797,889	34,896	(2,917)	829,868

APPENDIX D

Michigan Public Service Commission
DTE Electric Company
Projected Rate of Return Summary
For Period Ending April 30, 2020

Appendix D
Staff Initial Brief
Case No.: U-20162

	(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	6,382,775	48.98%	37.17%	4.36%	2.13%	1.62%	100.000%	1.62%
2	Preferred Stock	0	0.00%	0.00%	0.00%	0.00%	0.00%	134.964%	0.00%
3	Common Shareholders' Equity	6,648,924	51.02%	38.72%	9.80%	5.00%	3.79%	134.964%	5.12%
4	Total	13,031,699	100.00%			7.13%			
5	Short-Term Debt	112,875		0.66%	3.56%		0.02%	100.000%	0.02%
6	Investment Tax Credit (ITC) - Debt	10,433		0.06%	4.36%		0.00%	100.000%	0.00%
7	Investment Tax Credit (ITC) - Equity	10,858		0.06%	9.80%		0.01%	134.964%	0.01%
8	Total Investment Tax Credit (ITC)	21,291							
9	Deferred Income Taxes (Net)	4,006,648		23.33%	0.000%		0.00%		0.00%
10	Total	17,172,513		100.00%			5.45%		6.78%

APPENDIX E

Michigan Public Service Commission | **Appendix E**
DTE Electric Company | Staff Initial Brief
Capital Expenditure and Rate Base Adjustments | Case No.: U-20162
Projected 12 Month Period Ending April 30, 2020
($000)

	(a)	(b)	(c)	(d)	(e)	(f)
		Total	**Test Year Impacts From Staff Adjustments to Cap Ex Projects**			
Line	**Adjustment Description**	**Cap Ex Adj.**	**Plant Adj.**	**Accum Depr.**	**Rate Base**	**Depreciation**
1	CONTINGENCY: STEAM GENERATION - Combined Cycle - 2022	(10,533)	(8,217)	(120)	(8,097)	(158)
2	CONTINGENCY: CORPORATE STAFF - HQ Energy Center	(4,470)	(3,218)	(181)	(3,037)	(240)
3	TOTAL CONTINGENCY	(15,003)	(11,434)	(300)	(11,134)	(397)
4	STEAM GENERATION - Monroe Dry Fly Ash Processing	(34,100)	(21,767)	(396)	(21,371)	(653)
5	CHARGING FORWARD - Total Capital	(1,744)	(872)	(18)	(854)	(36)
6	DEMAND SIDE MGMT - Programmable Communicating Thermostats	(9,593)	(7,880)	(1,607)	(6,273)	(1,576)
7	IT - Corporate Application Projects	(625)	(313)	(31)	(281)	(63)
8	IT - Customer Service Projects	(3,674)	(2,144)	(235)	(1,909)	(429)
9	IT - Plant and Field Projects	(3,150)	(1,846)	(227)	(1,619)	(369)
10	IT- Information Technology for IT Projects	(6,170)	(4,452)	(290)	(4,162)	(334)
11	TOTAL IT	(13,619)	(8,754)	(783)	(7,971)	(1,195)
12	DISTRIBUTION PLANT - INFRASTRUCTURE REDESIGN - Total Capital	(74,188)	(57,662)	(1,998)	(55,663)	(2,376)
13	**Total Cap Ex Adjustments Impact**	(148,247)	(108,368)	(5,101)	(103,267)	(6,233)
14	Impact of Depreciation Rate Adj. on Accumulated Depreciation	Exhibit S-2, Schedule B1		(32,619)	32,619	
15	Working Capital Adjustments					
16	Reg. Liability - Active Health Care Credit	Exhibit S-2, Schedule B4			(4,334)	
17	DTE Corrected Error for Prepaid Pension Asset	Exhibit S-2, Schedule B4			(44,623)	
18	Charging Forward - Adjustment	Exhibit S-2, Schedule B4			(793)	
19	Charging Forward - Remove Double Count	Exhibit S-2, Schedule B4			(793)	
20	Interest Payable	Exhibit S-2, Schedule B4			(45)	
21	**Total Working Capital Adjustments**				(50,586)	
22	**Total Rate Base Adjustments**				(121,234)	

Source: WP-MLE-1

APPENDIX F

Michigan Public Service Commission
DTE Electric Company
Summary of Staff Position
Projected 12 Month Period Ending April 30, 2020
($000)

Appendix F
Staff Initial Brief
Case No.: U-20162

Walk from DTE Electric Revenue Deficiency (Initial Filing) to Staff Initial Brief

	(a)	(b)	(c)	(d)	(e)
Line	**Description**	**Source**	**Rate Base**	**Pre-Tax**	**Revenue Requirement Impact**
1	**Company Revenue Deficiency (Initial Filing - Total Co.)**	**DTE Initial Filing, Exhibit A-11, Schedule A1**			**$ 328.4**
2	Change in Rate base	Appendix E / Exhibit A-12, Schedule B1	(121,234)	7.19%	(8.7)
3	Change in rate of return	Appendix A / (Appendix D less A-14, Schedule A-14)	17,051,324	-0.42%	(71.2)
4	Sales Revenue Adjustment - RIA	Appendix C, line 10			(0.9)
5	O&M adjustment	Appendix C, line 10			(32.6)
6	Depreciation adjustment	Appendix C, line 10			(71.5)
7	Tree Trim Surge	DTE Initial Filing, Exhibit A-11, Schedule A1			(7.1)
8	AFUDC Adjustment	Appendix C, line 10			(2.6)
9	Tax Reform Regulaotry Liability Amortization Adjustment	Appenidx C, line			(0.6)
10	Total Staff adjustments (rev. req. impact)	Appendix A, line 8			(195.1)
11	Rounding				0.1
12	**Staff Initial Brief - Revenue Sufficiency (Total Co.)**	**Appendix A, line 8**			**$ 133.4**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	**Case No. U-20162** **(e-file paperless)**

____/

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF EATON)

PAMELA A. PUNG, being first duly sworn, deposes and says that on **January 11, 2019,** she served a true copy of **Michigan Public Service Commission Staff's Initial Brief** upon the following parties **via e-mail only:**

Administrative Law Judge
Hon. Sally Wallace
Administrative Law Judge
Michigan Public Service Comm.
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917
wallaces2@michigan.gov

Environmental Law & Policy Center
Margrethe Kearney
1514 Wealthy Street SE, Suite 256
Grand Rapids, MI 49506
mkearney@elpc.org

Bradley Klein
35 E. Wacker Drive, Suite 1600
Chicago, IL 60601
bklein@elpc.org

Energy Michigan, Inc.
Timothy Lundgren
Laura A. Chappelle
Varnum, LLP
The Victor Center, Suite 910
201 N. Washington Square
Lansing, MI 48933
tjlundgren@varnumlaw.com
lachapelle@varnum.law.com

Toni L. Newell
333 Bridge Street, NW
Grand Rapids, MI 49504
tlnewell@varnumlaw.com

ChargePoint, Inc.
Toni L. Newell
Justin K. Ooms
333 Bridge St., NW
Grand Rapids, MI 49504
tlnewell@varnumlaw.com
jkoms@varnumlaw.com

<u>Great Lakes Renewable Energy Association</u>
Don L. Keskey
Brian W. Coyer
University Office Place
333 Albert Avenue, Suite 425
East Lansing, MI 48823
donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com

Timothy J. Lundgren
201 N. Washington Square, Suite 910
Lansing, MI 48933
tjlundgren@varnumlaw.com

<u>Michigan Cable Telecommunications Association</u>
Michael S. Ashton
Anita G. Fox
Fraser Trebilcock Davis & Dunlap, P.C.
124 W Allegan, Suite 1000
Lansing, MI 48933
mashton@fraserlawfirm.com
afox@fraserlawfirm.com

<u>Michigan Environmental Council</u>, <u>Natural Resources Defense Council</u>, <u>Sierra Club</u>
Christopher M. Bzdok
Olson Bzdok & Howard
420 E Front Street
Traverse City, MI 49686
chris@envlaw.com

Karla Gerds, Legal Assistant
karla@envlaw.com
Kimberly Flynn, Legal Assistant
kimberly@envlaw.com
Breanna Thomas
breanna@envlaw.com

<u>Association of Businesses Advocating Tariff Equity</u>
Bryan A. Brandenburg
Clark Hill
212 E. Grand River Ave.
Lansing, MI 48906
bbrandenburg@clarkhill.com

Robert A.W. Strong
Michael J. Pattwell
Sean P. Gallagher
Clark Hill PLC
151 S. Old Woodward Ave., Ste. 200
Birmingham, MI 48009
rstrong@clarkhill.com
mpattwell@clarkhill.com
sgallagher@clarkhill.com

<u>Walmart, Inc</u>
Melissa M. Horne
Higgins, Cavanagh & Cooney, LLP
10 Dorrance Street, Suite 400
Providence, RI 02903
mhorne@hcc-law.com

Attorney General Dana Nessel
Joel King
525 W Ottawa Street
P. O. Box 30755
Lansing, MI 48909
kingj38@michigan.gov
ag-enra-spec-lit@michigan.gov

Sebastian Coppola
sebcoppola@corplytics.com

Residential Customer Group
Don L. Keskey
Brian W. Coyer
University Office Place
333 Albert Avenue, Suite 425
East Lansing, MI 48823
donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com

Solar Energy Industries Association, Vote Solar, The Ecology Center
Margarethe Kearney
1514 Wealthy Drive SE, Suite 256
Grand Rapids, MI 49506
mkearney@elpc.org

Bradley Klein
35 E. Wacker Drive, Suite 1600
Chicago, IL 60601
bklein@elpc.org

Unimuke John Agada, Legal Assistant
jagada@elpc.org

Institute for Energy Innovation, Michigan Energy Innovation Business Council
Laura A. Chappelle
Toni L. Newell
201 N. Washington Square
Suite 910
Lansing, MI 48933
lachappelle@varnumlaw.com
tlnewell@varnumlaw.com

Local 223, Utility Workers Union of America, AFL-CIO
Ben King
John R. Canzano
423 N. Main Street, Suite 200
Royal Oak, MI 48067
bking@michworkerlaw.com
jcanzano@michworkerlaw.com

DTE Energy
Andrea Hayden
Megan E. Irving
Lauren DuVal Donofrio
Jon P. Christinidis
One Energy Plaza
Detroit, MI 48226
andrea.hayden@dteenergy.com
megan.irving@dteenergy.com
lauren.donofrio@dteenergy.com
jon.christinidis@dteenergy.com
mpsc.filings@dteenergy.com

The Kroger Company
Kurt J. Boehm
Jody Kyler Cohn
Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
KBoehm@BLKlawfirm.com
JKylerCohn@BKLlawfirm.com
mkurtz@BKLlawfirm.com

Soulardarity
Lydia Barbash-Riley
420 E. Front Street
Traverse City, MI 49686
lydia@envlaw.com

Mark N Templeton
Robert A. Weinstock
6020 South University Ave
Chicago, ILL 60637
templeton@uchicago.edu
rweinstock@uchicago.edu

Pamela A. Pung

PAMELA A. PUNG

Subscribed and sworn to before me
this **11th** day of **January, 2019.**

De Ann M Payne

De Ann M. Payne, Notary Public
State of Michigan, County of Eaton
Acting in the County of Eaton
My Commission Expires: 11-29-24