S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

At the May 2, 2019 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner

ORDER

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I. HISTORY OF PROCEEDINGS

On July 6, 2018, DTE Electric Company (DTE Electric) filed an application requesting authority to increase its retail rates for the generation and distribution of electricity by $328 million, effective as early as June 6, 2019.[1] DTE Electric requested other forms of regulatory relief including miscellaneous accounting authority. The company is currently providing service pursuant to rates established by the April 18, 2018 (April 2018 order) and June 28, 2018 (June 2018 order) orders in Case No. U-18255 (together, the 2018 orders), and pursuant to various special contracts.

According to DTE Electric, the rate increase sought in this proceeding is based on the company's projections for relevant items of investment, expense, and revenue for a test year covering the 12-month period from May 1, 2019, through April 30, 2020. DTE Electric explained that the starting point for determining its revenue deficiency was the data from the year ended December 31, 2017. According to the company, this historical data was then normalized and adjusted for known and measurable changes to arrive at the company's projected test year.

In its application, the company stated that the rate increase was necessary to recover capital costs associated with additions to its generation and distribution system, capital structure cost changes, increased operations and maintenance (O&M) expense, and inflation and accounting standard changes. DTE Electric proposed a return on equity (ROE) of 10.50% with an overall rate of return of 5.76% after-tax, which equates to 7.19% pre-tax. The utility explained that it was relying upon a permanent capital structure of approximately 51% equity and 49% long-term debt.

[1] In its initial brief, DTE Electric supported a revised revenue deficiency of $250.2 million, and in its reply brief it requested $248.6 million. None of these amounts include the rate effect of the expiration of the Tax Cuts and Jobs Act of 2017 Credit A of $148.237 million, authorized in the July 24, 2018 order in Case No. U-20105. Inclusion of the Credit A-related revenue brings the original request to $476 million.

DTE Electric's projected rate base for the test year in its initial filing was approximately $17.2 billion.

On July 25, 2018, Administrative Law Judge Sally L. Wallace (ALJ) conducted a prehearing conference. The ALJ granted petitions to intervene filed by the Michigan Cable Telecommunications Association; Kroger Co. (Kroger); Michigan Department of the Attorney General (Attorney General); the Association of Businesses Advocating Tariff Equity (ABATE); Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), and Sierra Club (SC) (collectively, MEC/NRDC/SC); Energy Michigan; Great Lakes Renewable Energy Association (GLREA); ChargePoint, Inc.; Residential Customer Group (RCG); Environmental Law and Policy Center, Ecology Center (EC), Solar Energy Industries Association (SEIA), and Vote Solar (collectively, ELPC);[2] Michigan Energy Innovation Business Council and Institute for Energy Innovation (together, MEIBC/IEI); Local 223, Utility Workers Union of America, AFLCIO; and Wal-Mart, Inc. The Commission Staff (Staff) also participated. A schedule for the proceeding was established by the ALJ in accordance with the 10-month rate case deadline required by 2016 PA 341 (Act 341). On August 1, 2018, a protective order was entered. On August 21, 2018, Soulardarity's petition to intervene out of time was granted. On November 7, 2018, a motion to strike filed by MEC was denied.

Evidentiary hearings were held on December 12-14, and 17-19, 2018, where 25 witnesses appeared for cross-examination and the remaining witnesses had their testimony bound into the record by agreement of the parties. Timely initial and reply briefs were filed.

[2] Upon filing its exceptions, EC had apparently dropped from the ELPC group, and ELPC, SEIA, and Vote Solar began referring to themselves as the Joint Solar Advocates. Thus, this group is referred to in this order as either ELPC or the Joint Solar Advocates, depending on the phase of the case.

The ALJ issued a Proposal for Decision (PFD) on March 6, 2019. ABATE filed exceptions to the PFD on March 20, 2019, and DTE Electric, the Staff, the Attorney General, Kroger, RCG, GLREA, MEC/NRDC/SC, ELPC, Soulardarity, and Energy Michigan filed exceptions on March 25, 2019. Replies to the exceptions were filed by DTE Electric, the Staff, the Attorney General, MEC/NRDC/SC, MEIBC/IEI, ABATE, Energy Michigan, ELPC, Kroger, ChargePoint, RCG, and GLREA on April 5, 2019. The record consists of 4,307 pages of transcript, with testimony from 68 witnesses and over 400 exhibits received into evidence. Though not part of the evidentiary record, the docket also contains 3,017 public comments filed pursuant to Mich Admin Code, R 792.10413 (as of April 30, 2019); all but two of the 3,017 filed comments address aspects of the proposed distributed generation (DG) tariff.

II. TEST YEAR

In developing its rates for this proceeding, DTE Electric relied on a projected test year from May 1, 2019, through April 30, 2020, explaining that, in determining test year amounts, it began with the 2017 historical year, adjusted for known and measurable changes. While noting RCG's request to use an updated historical test year, the ALJ recommended that the Commission adopt the proposed test year. The ALJ noted that RCG did not raise this issue until its initial brief, offered no evidence of what the known and measurable changes should be, and failed to introduce the issue in a manner that would allow other parties to respond. PFD, pp. 28-29.

RCG excepted, arguing that the Commission should reject the use of a projected test year. Noting that MCL 460.6a(1) allows the utility to project costs for a future consecutive 12-month period, RCG argues that DTE Electric's projections in this case do not fall within the statutory time period because a "reasonable interpretation of the statute is that a projected test year for purposes of this case would be for the 12 consecutive months after DTE's rate filing on July 6, 2018." RCG's exceptions, p. 3. RCG later argues that the "projected test year should not exceed the 12 months after DTE's July 6, 2018 filing, at most the 12 months comprising August 1, 2018-July 31, 2019." *Id.*, pp. 6-7. RCG states that a test year that extends further simply adds to the speculative nature and unreliability of the forecasts and projections.

In reply, DTE Electric points to the language of the statute and argues that if the Legislature had intended to limit the projected test year it would have done so.

In its reply, ABATE indicates its support for RCG's position.

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

III. <u>RATE BASE</u>

A utility's rate base consists of the capital invested in used and useful utility plant, plus the utility's working capital requirements, less accumulated depreciation. In its application, DTE Electric projected a total electric rate base of approximately $17.2 billion. The Staff calculated a rate base of approximately $17.0 billion. The ALJ recommended a total rate base of $16,999,569,000.[3] DTE Electric, after exceptions, asserts that its rate base is $17,152,348,000.

A. Net Plant

1. Capital Contingency Amounts

DTE Electric removed $4.5 million from its request for contingency capital expenditures (this amount was associated with the proposed Headquarters (HQ) Energy Center), but continues to request $10.5 million in contingency costs associated with the construction of a new natural gas combined cycle (NGCC) plant. Construction of the plant was approved in the April 27, 2018 order in Case No. U-18419 (April 27 order), wherein the Commission granted DTE Electric certificates of necessity (CONs) for the NGCC plant. The Staff, the Attorney General, MEC/NRDC/SC, and RCG objected to the inclusion of contingency amounts in net plant.

Referring to Commission precedent on the issue of contingency budgeting, the ALJ recommended disallowance of the $10.5 million in NGCC contingency costs. PFD, p. 31.[4]

In exceptions, DTE Electric argues that contingency amounts were specifically authorized in the April 27 order where the Commission stated that the CON approval includes "$17.8 million for contingency costs. Only actual amounts incurred up to $951.8 million shall be recoverable through rates." April 27 order, p. 126. DTE Electric asserts that it would be premature to

[3] Several rate base items were agreed upon by the parties or faced no opposition, including: (1) Midwest Energy Resources Company (MERC) capital expense; (2) nuclear capital expense; (3) removal of $4.5 million in contingency costs from capital expense; (4) capital expenditures for community lighting; and (5) depreciation reserve. PFD, pp. 30, 60-61, 88, and 104. DTE Electric also agreed to update its general and intangibles direct assignment study for its next rate case. PFD, p. 300. The ALJ recommended adoption of each of these items and the Commission agrees.

[4] The Attorney General, in exceptions, notes that the PFD contains a typo on page 31. Where the ALJ disallows a total of "$15,003.00" in contingency costs, the PFD should read "$15,003,000."

"disallow a portion of the approved funding," especially in light of the fact that the company has not exceeded the total amount approved in the April 27 order. DTE Electric's exceptions, p. 5.

In reply, the Attorney General notes that in the CON case the Commission approved for future recovery only "actual amounts incurred," and contingency amounts are inherently speculative. April 27 order, p. 126. In their replies, the Staff and MEC/NRDC/SC make the same points.

The Commission agrees with the ALJ that DTE Electric's projected contingency costs should be disallowed. As the Commission has repeatedly found, although allowing for contingency may be appropriate in project planning, the inclusion of these costs in customer rates is unjust and unreasonable. *See*, November 19, 2015 order in Case No. U-17735, pp. 7-11; December 11, 2015 order in Case No. U-17767, pp. 19-20; December 9, 2016 order in Case No. U-17999, pp. 4-6; and January 31, 2017 order in Case No. U-18014, pp. 12-13. Pursuant to the order in the CON case, amounts actually spent, up to the approved total of $951.8 million, may still be recovered. April 27 order, p. 126.

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

a. Monroe Dry Fly Ash Projects

The Monroe dry fly ash (DFA) projects include processing, conversion, and transportation projects related to compliance with the effluent limitation guidelines (ELG) promulgated by the U.S. Environmental Protection Agency (EPA) in 2015. Though supportive of the goals as a whole, the Staff proposed disallowance of approximately $34.1 million in proposed costs for the four-month bridge period[5] and the test year combined, based on the fact that DTE Electric has not received full internal approval for all of the projects and has not executed an engineering,

[5] For purposes of this order, the bridge period is January 1, 2018, through April 30, 2019, unless stated otherwise. *See e.g.,* PFD, p. 35. Where calendar year 2018 is broken out separately, the bridge period is January 1, 2019, through April 30, 2019.

procurement, and construction (EPC) contract yet. The Staff also indicated that it had inadequate information regarding the net present value revenue requirement (NPVRR) of the projects. The Attorney General recommended disallowance of $90.9 million. MEC/NRDC/SC supported the Staff.

The ALJ recommended disallowance of the $34.1 million, agreeing with the Staff that only limited corporate approval had been shown and that the NPVRR does not demonstrate a net benefit to customers. The ALJ recommended rejection of the Attorney General's arguments for additional disallowances associated with projects that had been adequately supported on the record; she found the proposed amounts to be reasonable and necessary and unrelated to the EPA's potential changes to the ELG rules. PFD, pp. 36-37.

In exceptions, DTE Electric notes that the Staff found value in the DFA project for ratepayers and the environment. 8 Tr 4191. The utility contends that the project will lower power supply cost recovery (PSCR) costs and reduce solid waste. DTE Electric states that it "has received internal project approval and has completed benchmarking and conceptual design of the project." DTE Electric's exceptions, p. 4; 4 Tr 600.

In reply, the Attorney General contends that management approval remains uncertain, the company presented an inadequate NPVRR, and no EPC contractors have yet been hired. The Attorney General argues that the benefit to ratepayers is only a theoretical possibility.

In its reply, the Staff reiterates that the cost estimates are uncertain and full internal budgetary approval has not been shown. 8 Tr 4191. The Staff states that it was not able to fully evaluate the DFA project for reasonableness and prudence based on the company's case, but notes that the company may include these costs in a subsequent rate case with more complete information.

In their reply, MEC/NRDC/SC note that DTE Electric did not rebut the Staff's testimony showing that the analysis was insufficient and that final budgetary approval had not been given, and provided nothing new in its exceptions.

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

b. River Rouge Unit 3 Capital Expense

River Rouge Unit 3 (Unit 3) is a Tier 2 coal-fired generation unit that DTE Electric plans to retire in May 2020. 4 Tr 523. DTE Electric requested inclusion in rate base of capital costs of $8.45 million incurred through December 31, 2018 (2017-2018), and capital costs of $1.87 million for 2019 through the test year, as well as O&M costs through that period of $17.65 million. PFD, pp. 46, 138; Exhibit MEC-98, p. 3; Exhibit A-12, Schedule B5.1. DTE Electric provided an updated NPVRR analysis of the retirement of Unit 3 which compares retirement by December 2018 to retirement by May 2020 and favors the latter. 3 Tr 367-368; Exhibit A-12, Schedule B6. MEC/NRDC/SC argued that the analysis and their own evidence shows that earlier retirement would have benefited ratepayers and that resource adequacy is not constrained in Local Resource Zone 7 (Zone 7).

The ALJ described past Commission orders as having deferred a decision on capital costs for continued operation of Unit 3 until DTE Electric submitted an updated NPVRR analysis of the retirement decision. The ALJ recommended allowance of the "previously deferred capital costs, totaling $8.45 million" expended through December 31, 2018, finding them to be minimal and reasonably incurred. PFD, p. 46. She recommended disallowance of capital costs of $1.87 million for Unit 3 for 2019 through the end of the test year, finding that DTE Electric had failed to show that they are reasonable and prudent. The ALJ found that MEC/NRDC/SC provided convincing evidence that "the economics of operating RR 3 until the end of the test year is more likely than not to be detrimental to ratepayers and that there is significantly greater benefit to retiring the unit in December 2018." PFD, p. 47. She recommended disallowance of O&M costs for Unit 3 for that period as well, on the same basis. PFD, pp. 47, 138.

In exceptions, while agreeing with the ALJ's other decisions, MEC/NRDC/SC argue that the available evidence supports the continued disallowance of the 2017 and 2018 capital costs as well, and that, if the Commission decides to approve O&M costs (as it has done in recent cases addressing Unit 3), then it should also deny the 2017-2018 capital expenditures. MEC/NRDC/SC argue that the updated NPVRR still fails to show that it was less costly for DTE Electric to incur these expenses in 2017 and 2018 for Unit 3 than to retire the unit in 2016. MEC/NRDC/SC reject the ALJ's reference to the fact that no specific retirement date for Unit 3 was ever evaluated as a basis for awarding the past costs. PFD, p. 46. MEC/NRDC/SC point out that they have argued all along that the utility should have evaluated a 2016 or 2018 retirement once DTE Electric decided to retire River Rouge Unit 2 in 2016. MEC/NRDC/SC contend that DTE Electric has not rebutted their evidence showing that it would have been less costly to retire the unit in 2016 than to operate it through 2020. MEC/NRDC/SC's exceptions, p. 5. MEC/NRDC/SC aver that allowing these past costs would simply reward DTE Electric for failing to ever evaluate a 2016 retirement and for delaying the NPVRR. MEC/NRDC/SC refer to their witness's testimony showing that Unit 3 lost money in 2015, 2016, and 2017. 6 Tr 2596-2599.

In exceptions, DTE Electric argues that the ALJ erred in disallowing future capital and O&M expense in this category. DTE Electric contends that operation of Unit 3 through May 2020 is justified on this record through the NPVRR and other factors. The company notes that its integrated resource plan (IRP) filing was required on March 29, 2019, and argues that the IRP proceeding is the proper forum for evaluating plant retirement dates. Thus, DTE Electric maintains, the ALJ erred in evaluating the Unit 3 retirement date on this record.

DTE Electric further argues that projected costs to run the unit cannot be examined purely on an economic basis, but other factors such as community impacts, grid reliability, and workforce planning must also be taken into account. DTE Electric posits that MEC/NRDC/SC's criticisms of the NPVRR are purely economic, and that resource adequacy is always a moving target. DTE Electric also objects to the ALJ's disallowance of O&M costs of $17.7 million, pointing out that the Commission allowed these costs in past rate cases.

In reply to MEC/NRDC/SC, DTE Electric notes that in the 2018 orders the Commission approved O&M cost recovery for Unit 3, and argues that the NPVRR supports continued operation of the unit through May 2020. Exhibit A-12, Schedule B6. DTE Electric also objects to MEC/NRDC/SC's apparent argument that the capital expense and O&M costs must be balanced out. The company reiterates that the decision regarding retirement of the unit involves more than a simple economic analysis.

In their reply, MEC/NRDC/SC note that this is the third time in three years that DTE Electric has tried to recover capital expense associated with Unit 3 without adequately supporting the costs, and argue that the updated NPVRR demonstrates that the unit is uneconomic. 6 Tr 2596-2599. MEC/NRDC/SC point out that the company offered no evidence rebutting MEC/NRDC/SC's testimony showing that the unit has lost, and continues to lose, money. MEC/NRDC/SC posit that the issue in this case is whether ratepayers should pay the costs of continuing to operate Unit 3, and not what the retirement date should be. MEC/NRDC/SC contend that they showed that the only scenario in which continued operation of Unit 3 produces an economic benefit is if capacity prices jump to 100% of the cost of new entry. MEC/NRDC/SC further argue that consideration of non-economic factors is not dispositive because it still comes down to whether ratepayers should be obligated to assume this burden. MEC/NRDC/SC also argue that O&M recovery should be denied because these costs are unreasonable in light of the fact that the unit is uneconomic. As in their exceptions, MEC/NRDC/SC contend that if the Commission disallows future O&M costs, it should also disallow the past capital expense.

In the December 11, 2015 order in Case No. U-17767, p. 14, the Commission disallowed capital costs associated with environmental retrofits for Unit 3 because they were not shown to be cost effective. In the January 31, 2017 order in Case No. U-18014, p. 17, the Commission again disallowed capital costs for Unit 3. In that order, the Commission found that the utility had decided to permanently shut down River Rouge Unit 2 but had not updated any of the assumptions in the NPVRR for Unit 3, despite knowing that Units 2 and 3 shared many costs; thus, again failing to show that the capital expenditure was cost effective (the Commission allowed O&M costs). In the 2018 orders, the Commission again disallowed capital costs for Unit 3 based on the continued failure of the utility to update the NPVRR and its entire analysis of Unit 3 with a showing of clear cost effectiveness, but allowed O&M costs. April 2018 order, p. 8, and June 2018 order, p. 5.

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

c. St. Clair Units 1, 2, 3, and 6 Capital Expense

Similar issues were raised by MEC/NRDC/SC with respect to capital costs for St. Clair Units 1, 2, 3, and 6, which are planned for a 2022 retirement. MEC/NRDC/SC argued that retirement should come sooner.

The ALJ recommended that issues related to the timing of the retirement of the St. Clair and Trenton Channel units should be addressed in DTE Electric’s IRP proceeding, Case No. U-20471 filed on March 29, 2019. Because these units will not retire for another three years, the ALJ found that they are not similarly situated to Unit 3, and recommended that DTE Electric be directed to submit an updated NPVRR for these units in its next rate case. PFD, p. 49.

No exceptions were filed and the Commission adopts the findings and recommendations of the ALJ. However, the Commission notes that in DTE Electric’s March 29, 2019 filing in Case No.

U-20471, the company indicates that St. Clair Unit 1 was shut down sometime in February 2019, and the Midcontinent Independent System Operator, Inc. (MISO) approved DTE Electric's request to retire St. Clair Unit 1 effective March 27, 2019. Case No. U-20471, March 29, 2019 application, p. 2; direct testimony MTP-14, LKM-59, and SGP-34 to SGP-35. Thus, the Commission expects the utility to repurpose the capital expense associated with St. Clair Unit 1 on this record after the date of shutdown of that unit for use on other units in need, and to present that expense information in its next rate case filing.

d. Combined Heat and Power Plant

DTE Electric proposes development of a new 34 megawatt (MW) combined heat and power (CHP) plant on the campus of Ford Motor Company (FMC) Research and Engineering Center (Ford REC). The plant will be constructed and operated by DTE Power and Industrial (DTE P&I) and owned by DTE Electric at the conclusion of construction pursuant to contracts between DTE Electric and DTE P&I. DTE Electric and DTE P&I are both subsidiaries of DTE Energy Company (DTE Energy) and affiliated companies. FMC put out a request for proposals (RFP) for the plant and DTE Energy was the winning bidder, having submitted a bid that included the involvement of both DTE Electric and DTE P&I (as well as DTE Gas Company (DTE Gas)). 4 Tr 554-555; 5 Tr 1129-1130. Thereafter, DTE Electric negotiated with DTE P&I, only, for the building and operation of the CHP plant, and the transfer of ownership to DTE Electric when the build is complete and other contractual conditions are met. 8 Tr 4193. The CHP plant will provide steam to Ford REC and electrical energy to FMC and other DTE Electric customers. 4 Tr 553. The development project is expected to be completed by December 31, 2019, at a cost of $62.3 million, which DTE Electric proposes for inclusion in rate base in this rate case. This is all capital expense; DTE Electric seeks no O&M expense.

Because the purchase of the CHP plant by DTE Electric from DTE P&I is an affiliate transaction, DTE Electric contracted with HDR to develop an independent estimate of the cost of a 34 MW CHP plant (HDR report). Exhibit A-28, Schedule R2. That estimate came in at $84.6 million, which, DTE Electric represented, reflects the market price, thus making the transaction compliant with the Code of Conduct which requires that transactions for products or services between a utility and an affiliate be at the lower of market price or 10% over fully allocated embedded cost. Mich Admin Code, R 460.10108(4) (Rule 108(4)) (effective January 9, 2019); October 29, 2001 order in Case No. U-12134, Attachment A, Part III.C; 5 Tr 1130; Exhibit A-28, Schedule R2. DTE Electric asserted that the CHP project allows the utility to retain FMC as a bundled customer, which has an NPV of $102.1 million over the 30-year life of the CHP plant for ratepayers. 5 Tr 1133-1134. At the request of the Staff, DTE Electric performed a levelized cost of energy (LCOE) analysis that showed that the cost of the CHP plant was competitive with alternative generating technologies. 8 Tr 4193-4194. The Staff was satisfied with the project, but suggested that, if the Commission finds the LCOE analysis inadequate, the utility should engage in a competitive bidding process for construction of the plant. The Attorney General and MEC/NRDC/SC found a lack of transparency and raised questions about whether the purchase price complies with the test laid out in the Code of Conduct.

The ALJ recommended that the Commission deny DTE Electric's request to include the $62.3 million in rate base because the utility failed to demonstrate that the purchase of the CHP plant from an affiliate company complies with the Code of Conduct. PFD, p. 58. The ALJ found that the HDR report "does not establish an independent market price . . . [T]he report is much more akin to a solitary bid than anything that could be remotely described as a definitive market price." *Id.* The ALJ found the vast difference between the DTE Electric price and the HDR estimate (about $22 million) indicative of the fact that the estimate may not be valid, and noted that an RFP process could have established a market price. The ALJ noted little dispute that the LCOE analysis establishes that the cost of the generation is reasonable and that there are ratepayer benefits to retaining FMC as a DTE Electric customer, but found that the utility had not demonstrated compliance with the Code of Conduct requirements for transactions between utilities and their affiliates. PFD, p. 59.

In exceptions, DTE Electric argues that the record demonstrates that the price paid to DTE P&I is at or below market price and thus complies with Rule 108(4). DTE Electric states that it retained HDR to develop the cost estimate prior to contracting with DTE P&I, and states the cost estimate "was used to inform negotiations with P&I." DTE Electric's exceptions, p. 16. DTE Electric avers that the LCOE analysis shows that the energy price is competitive with alternative generation technologies. 5 Tr 1131. DTE Electric posits that the LCOE analysis and the cost estimate are supported by the contracts with DTE P&I (filed confidentially); and by HDR's supporting documents and workpapers used in preparing the cost estimate, including estimates from multiple equipment vendors (filed confidentially). Confidential Exhibit A-41, Schedules DD1-DD8. DTE Electric accuses the parties of disregarding these documents.

DTE Electric also notes that the Code of Conduct does not specify a method for determining market price, and certainly does not require competitive bidding. The company points out that it is too late to competitively bid the plant, which will be completed in a few months. The company asserts that there should be alternative means for showing a market based price, as the ALJ herself suggested. PFD, p. 59, n. 94. Noting that MEC/NRDC/SC objected to $14 million in contingency costs included in the HDR report, DTE Electric points out that the market price would still be $70.6 million if all of the contingency is removed. Finally, the company notes that no party disputed the fact that the project has many benefits for ratepayers including energy at a good price and retention of DTE Electric's largest bundled customer.

In exceptions, the Staff objects to the ALJ's removal of the CHP plant from rate base and argues that she erred in her analysis of the Code of Conduct. The Staff contends that in speaking of an "independent" market price and a "definitive" market price the ALJ imposed new and additional conditions that do not exist in Rule 108(4). PFD, p. 58. The Staff points out that the Code of Conduct does not require competitive bidding or any competitive process, or even a particular method for determining market price. The Staff contends that "the code's silence regarding particular methods of determining fair market price inherently acknowledges that various methods could be used." Staff's exceptions, p. 4. The Staff maintains that a determination of market price will necessarily rely on estimates, which by definition cannot be definitive, and that the ALJ engaged in speculation when she questioned the validity of the HDR report based on the difference between the actual cost and the estimated cost. The Staff argues that her decision is not based on the record evidence and should be rejected.

In reply, DTE Electric agrees with the Staff.

In her reply, the Attorney General argues that this affiliated transaction lacks transparency and undercuts the credibility of the price negotiated between the affiliates. The Attorney General maintains that a single, solicited study is not a reasonable process for establishing market price, and the details of the contracts between DTE Electric and DTE P&I do not add support.

In their reply, MEC/NRDC/SC argue that nothing in the FMC RFP or in the project agreements required that the plant be constructed by a DTE Electric affiliate, thus DTE Electric was not prevented from competitively bidding the CHP plant. Exhibit MEC-153; 5 Tr 1170. MEC/NRDC/SC further point out that "DTE Electric convinced Ford to allow the utility to own the plant." MEC/NRDC/SC's replies to exceptions, p. 22; 5 Tr 1158-1159. MEC/NRDC/SC contend that transactions between affiliates require special scrutiny in order to protect ratepayers and that, in this situation, competitive bidding was necessary in order to ensure that preferential treatment was not given to the affiliate DTE P&I and to establish a valid market price. Rule 108(3), (4). Since DTE P&I was not required to compete with other vendors, MEC/NRDC/SC insist that preferential treatment took place. MEC/NRDC/SC argue that the Commission has previously disapproved of the use of a utility-commissioned appraisal in lieu of competitive bidding to meet Code of Conduct requirements in the November 16, 1999 order in Case No. U-11636, pp. 17-19, where the Commission rejected an appraisal of a facility provided by a consulting firm to Consumers Energy Company (Consumers), because the single appraisal was based primarily on information supplied by Consumers (the owner) to the appraiser. MEC/NRDC/SC contend that the HDR report provides as much credible value as the report rejected in that case. MEC/NRDC/SC note that the HDR report is unsigned and the authors are unknown, and the ALJ recognized that it was classic hearsay but allowed it into evidence under the liberal evidentiary rules applicable to the Commission. Mich Admin Code, R 792.10125; November 7, 2018 Ruling on Motion to Strike, pp. 7-8. Without a witness knowledgeable about the methods underlying the HDR report, MEC/NRDC/SC argue, the report could neither be challenged nor defended.

The Commission agrees with the Staff that the CHP plant provides value to ratepayers. However, the Commission is not bound by any single formula when setting rates, and is free to make pragmatic adjustments warranted by the particular circumstances. *Michigan Bell Tel Co v Public Service Comm,* 332 Mich 7, 36-37; 50 NW2d 826 (1952); *Attorney General v Public Service Comm,* 189 Mich App 138, 148; 472 NW2d 53 (1991); *In re Application of Consumers*

Energy Co, 313 Mich App 175, 193; 881 NW2d 502 (2015). The Commission finds that the utility's handling of the CHP plant transaction presents such particular circumstances. While DTE Electric is correct that Rule 108(4) does not require competitive bidding, the ALJ is also correct that the HDR report represents a "solitary bid." Not only did DTE Electric fail to seek a bid from any party other than DTE P&I (an affiliate), it also failed to seek any other estimate of a market price. Moreover, the HDR report itself leaves much to be desired. Confidential Exhibit A-41, Schedule DD8, contains some evidentiary support for the cost estimate. However, as MEC/NRDC/SC point out, the cost estimate itself contains $14.1 million ($7.05 million each) in contingency costs for "EPC Contingency" and "EPC G&A [general and administrative] and Fee." Exhibit A-28, Schedule R2, p. 5. The report is "an AACE [Association for the Advancement of Cost Engineering] Class 3 estimate, meaning it has a -20%/+30% accuracy range." Exhibit A-28, Schedule R2, p. 3. If the contingency amounts are deducted from the total (*see* pp. 6-7, *supra*) and the -20% range of inaccuracy is applied, the cost estimate is reduced to $56.4 million (10% below the actual price); even if only half of the contingency amount is deducted, the cost estimate is still reduced to $62.0 million (slightly below the actual price). No knowledgeable witness was provided by the utility to support the HDR report, making it an essentially untested piece of evidence. The fact that it was the only market price estimate that DTE Electric provided to the Commission, combined with the Commission's low degree of confidence in the estimate, added to a timing problem that now precludes competitive bidding, all means that the price agreed between DTE Electric and DTE P&I comes into question. This in turn impacts the credibility of the LCOE, which is based upon the contractual price.

For all of these reasons, the Commission finds that the CHP plant should be included in rate base, but with a disallowance of 10% of incremental plant additions for the test year, for which

DTE Electric requested a total of $22.48 million. Exhibit A-12, Schedule B5.1. This translates to a permanent disallowance of $2.248 million from capital expense; DTE Electric may not include this amount in any future rate cases for recovery, no matter what the final amount of incremental capital expense for the test year, or total cost, turns out to be. The Commission finds that the plant is appropriate for rate base treatment because the cost of the energy is very likely in the neighborhood of what is reflected in the LCOE analysis and represents good value for ratepayers, and because DTE Electric showed (and no party convincingly disputed) that retention of FMC as a bundled customer has a clear benefit for ratepayers. The Commission finds that the disallowance is appropriate in light of DTE Electric's inadequate demonstration of market price and decision to present the issue to the Commission after it was too late to seek competitive bids or even a facsimile of such. Thus, the Commission must fashion a disallowance based on the record it has. The 10% of incremental plant additions for the test year, which amounts to about 3.57% of the total requested cost, is well within the margin of error applicable to what the utility calls a credible market price. The Commission finds it is reasonable to apply this small margin of error to the contractual price, in the interests of ratepayers, because the contractual price was not adequately supported by the company. The Commission does not find that competitive bidding is required in every case for compliance with Rule 108(4); but the Commission does find that in this particular factual situation, should it arise again, competitive bidding of the build and transfer contract (entered into by DTE Electric) would be required, and DTE Electric should plan accordingly.

3. Distribution Capital Expense

a. Five-Year Distribution Plan

Pursuant to the Commission's directive in the January 31, 2017 order in Case No. U-18014, pp. 40-41, DTE Electric developed a five-year distribution plan, with a focus (for the present) on customer safety and system reliability. *See also*, October 11, 2017 order in Case No. U-18014, pp. 10-12. The ALJ found that the five-year plan has value in providing visibility into system needs, but does not play into cost recovery decisions at this point. PFD, pp. 65-66; *see* November 21, 2018 order in Case No. U-20147, pp. 36-37.

In exceptions, DTE Electric argues that there should be no delay in implementation of the investments described in the five-year plan.

The Commission finds no specific issue that requires decision here. The five-year plan filed by the company complies with the Commission's prior orders and provides significant and useful information on future system needs. Any investment for which DTE Electric has requested capital expense or O&M treatment in this rate case is addressed herein.

b. The Staff's Adjustments to 2017 Historical Distribution Operations Spending

Based on the Staff's testimony regarding the utility's penchant for changing the names of expense categories and the difficulty of aligning spending categories in adjoining rate cases, the ALJ recommended that, in light of the tight 10-month timeframe, the Commission revise the rate case filing requirements to require the utility to explain how spending classifications in a previous rate case translate into the current rate case. PFD, p. 67.

In exceptions, DTE Electric states that it appreciates the ALJ's concern and "will endeavor to address these issues on a going-forward basis." DTE Electric's exceptions, p. 25.

In reply, the Attorney General argues in support of the ALJ's proposal.

The Commission appreciates DTE Electric's willingness to address this issue. Changing the names of expense categories between rate cases will indeed cause unnecessary confusion and waste of time. When rate cases are filed only 12 months apart, as they currently are, the confusion and loss of time are even greater. The Commission does not find it necessary to revise the rate case filing requirements at this time. With greater clarity in future filings this will not become necessary.

c. The Staff's Adjustments to 2018 Distribution Operations Spending

The Staff initially recommended a disallowance of approximately $65.5 million which was reduced to $19.223 million in its initial brief, from the $810.2 million total requested by the company for 2018. The Staff disagreed with DTE Electric's projection for Emergent Replacements, arguing that it assumes higher-than-forecasted spending for November and December 2018 for this volatile expense, based on extrapolating the higher-than-normal expense incurred from January through October resulting from a particularly stormy year. The Staff recommended adoption of the company's originally-proposed amount for those two months. The ALJ recommended adoption of the Staff's disallowance, finding that storm activity in early 2018 was higher than usual but need not be carried over into the later part of the year, and that the Staff had shown that there were sufficient funds to cover distribution operations costs for the remainder of 2018. PFD, p. 71.

In exceptions, DTE Electric objects to the special treatment for Emergent Replacements for November and December of 2018, arguing that straight-line extrapolation from the December-October time period should be used. The utility argues that forecasts should be applied consistently and that there is no evidentiary support for lowering the forecast for those two months. DTE Electric posits that the first part of 2018 was very stormy and that storms are also commonplace in November-December. 4 Tr 838-845. DTE Electric objects to the Staff's opinion that the forecasted amount is simply too high.

In reply, the Staff argues that spending in Emergent Replacements is volatile, but that the Commission should not assume that spending in November and December would have been greater than originally forecasted by DTE Electric itself.

The Commission agrees with the ALJ and adopts the Staff's 2018 adjustment to the final two months of the year, which is based on the original cost projected by the utility. Weather is, of course, highly volatile, and the original projections would have taken that into account already. The fact that the first ten months of 2018 brought more storms than in a normal year does not provide a basis for finding that November and December would be the same way. The Commission adopts the $790.934 million supported by the Staff for this category.

d. The Staff's Adjustments to Bridge Period and Test Year Distribution Spending

The Staff recommended adjustments to the bridge period and test year spending, all of which flow from the adjustment to 2018 distribution capital spending. In its initial brief, the Staff proposed a downward adjustment to the four months ending April 30, 2019, of $21.912 million, and for the test year of $31.447 million. These disallowances are based on taking the Staff's recommended 2018 capital expense amount and adopting it for 2019. The Staff opined that Strategic Capital spending, which was below projections for 2018, would continue to trend below projections for 2019; that Emergent Replacements spending would be near the amount the utility projected; and that spending on Connections and Other would also be near the amount the utility projected. 8 Tr 4118. For the bridge period, the Staff testified that Emergent Replacements would be about 75% of DTE Electric's projection, and that Strategic Capital spending would be about 77.9% of the company's projection. For the test year, the Staff made similar extrapolations but increased Strategic Capital spending during the test year. In sum, the Staff posited that DTE

Electric would spend in 2019 about the same amount as the Staff's projection for 2018. Staff's initial brief, pp. 43-44.

The ALJ agreed with the Staff, but also agreed with DTE Electric that the Staff had mistakenly omitted to add inflation to 2019. Therefore, she recommended approval of the disallowances calculated by DTE Electric in its reply brief, including 2019 inflation of 2.23%, of $16.033 million for the bridge period and $15.268 million for the test year. PFD, p. 76; DTE Electric's reply brief, pp. 33-34. The ALJ noted that the Staff's 2018 projection was reasonable (as discussed above), and found that the Staff appropriately ramped up Strategic Capital spending in the test year.

In exceptions, the Staff contends that inflation should not be added to 2019 "because the 2018 amount is a reasonable amount for 2019 as well." Staff's exceptions, p. 2. This again is based on the Staff's argument that spending in the Strategic Capital category will fall short of projections (because it is already behind) and spending on Emergent Replacements will not be as high as it was in 2018.

In its exceptions, DTE Electric contends that the Staff arbitrarily adjusted the 2018 amount for Emergent Replacements and this provided a flawed starting point for adjusting the 2019-2020 amounts. DTE Electric also argues that the Staff did not consider the merits of the five-year plan but instead simply used historical costs to forecast future expense, noting that this will result in under-forecasting when there is a planned spending increase. DTE Electric argues that it complied with the Commission's directive in the October 11, 2017 order in Case No. U-18014 to reexamine its spending and focus on the five-year plan to address reliability issues, and that the Staff's historical method ignores this directive and refocuses on the status quo. DTE Electric contends that its investments are driven by the five-year plan, which was developed with the goals of reducing risk, improving reliability, addressing aging infrastructure, and managing cost. Exhibit A-23, Schedule M5. DTE Electric maintains that the Staff's "historical costs plus inflation" approach negates the five-year plan, even though the plan was developed in collaboration with the Staff. The company argues that, without actually disagreeing with the plan, the Staff proposed disallowances that arbitrarily reduce the funding needed to execute the plan. DTE Electric also criticizes the Staff's approach to Strategic Capital as arbitrary in that the Staff seems to simply pick a middle ground of 81.9% spending that has no basis in record evidence or system needs.

In its reply, the Staff argues that its position does not represent a return to the status quo; but rather that the Staff's 22.4% increase over 2017 spending is more reasonable than the company's proposed 27.5% increase over 2017. Staff's replies to exceptions, p. 2. The Staff argues that even with its proposed disallowance the company will receive about $146.15 million more for this category than it spent in 2017 and that this should "allow the Company to make a good deal of progress in implementing the Five-Year plan." *Id.*, p. 3. The Staff points out that the Strategic Capital category was behind in 2018 spending and posits that it will remain behind in the bridge and test year periods. 8 Tr 4118. The Staff also notes that weather was not the only factor that affected Strategic Capital spending in 2018 – that there was also delay and postponement of projects, which could persist into 2019.

In reply to the Staff, DTE Electric contends that the Staff's argument regarding 2019 inflation should be rejected because it lacks evidentiary support.

The Commission disagrees that the Staff's adjustment to 2018 spending is arbitrary; that adjustment is based on the company's original forecast. However, the Commission does find the Staff's proposed adjustments to the 16 months of the bridge period and test year to be somewhat arbitrary in the sense that the Staff posits that 2019 will look much like 2018. As stated, DTE

Electric's proposed five-year plan complies with the directives of the Commission and its bridge and test year period proposed spending is described in considerable detail, whereas the Staff's adjustments appear to be based on generalizations. The Staff posits that since there was under-investment in the proactive spending categories in 2018, this under-investment pattern will continue. The Commission is not persuaded, however, particularly in light of the plethora of project level detail supporting the planned work in the test year, and these projects address the goals outlined in the five-year plan. Based on the record evidence provided by the company, the Commission approves DTE Electric's capital expense distribution operations projections for the bridge period and test year of $285.6 million and $830.6 million, respectively. The Commission stresses the importance of strengthening and modernizing DTE Electric's electric distribution system to ensure safe, reliable operations for customers throughout its service territory and to integrate new technologies. The evidence in this proceeding, including the five-year distribution plan, outlines capital investment priorities to best meet objectives and address inherent risks associated with aging infrastructure. The Commission will closely monitor implementation of these investments and of the five-year plan.

e. The Attorney General's Distribution Operations Spending Adjustments

i. New Business

The Attorney General proposed a $9.8 million reduction for 2018 based on the fact that DTE Electric underspent by 36% in the first four months of 2018 in this expense category. She also argued that the low number of potential future projects showed that the expense was not warranted.

The ALJ recommended adoption of DTE Electric's projections for this category, finding that the overall spending category to which New Business is assigned was actually overspent by

August 2018, that DTE Electric had shown that its estimates were conservative, and that DTE Electric had shown an increase in new projects locating in its service territory. PFD, p. 78.

In exceptions, the Attorney General argues that DTE Electric provided no detail on its alleged overspend in other areas, and that it is poor policy to allow an overspend in another area to provide support for an underspend. The Attorney General contends that DTE Electric did not provide adequate support for its bridge period and test year spending ($11.3 million and $39.9 million, respectively) in this area, because its historical information for 2013-2017 lacked detail.

In reply, DTE Electric argues that the ALJ's recommendation is supported by the record, including by the Attorney General's own Exhibit AG-13, which shows that the Connections and New Load category was overspent by $1 million through August 2018 and contains the subcategory of New Business. DTE Electric contends that it is not appropriate to base a disallowance on an isolated mid-year underspend, when overall spending in the broader category was higher than projected. 4 Tr 857. The company notes that all of these categories are for addressing connecting customers and that the overall costs are broken into subcategories for the purposes of project management only, and DTE Electric seeks some flexibility between categories because it cannot predict the exact blend of small and large connection projects. 4 Tr 903-904. DTE Electric posits that New Business projects have a high likelihood of occurring. Turning to the Attorney General's argument to disallow all bridge and test year period spending, DTE Electric states that New Business has experienced a 37% compounded annual growth over 2013-2017 and that its current future projections are conservative. 4 Tr 775, 858-862. The company points out that it is obligated to make these expenditures in response to customer requests.

The Commission adopts the findings and recommendations of the ALJ. It is true that all of these categories address the costs of connecting new customers or new business, and that the overall category was overspent. The overspend is not actually in another area, but in the umbrella category that covers new connecting customers. The Commission is also persuaded that New Business is growing and that increased pace in this area will continue, and the Attorney General's exception is rejected.

ii. Infrastructure Resilience and Hardening/Redesign

Similar to New Business, the Attorney General proposed a reduction to this expense category based on the fact that DTE Electric had spent less than its projected amount in the first eight months of 2018. The ALJ found that, since she had already adopted the Staff's proposed adjustments for 2018, 2019, and the test year distribution expense, any additional adjustment would be unnecessary and duplicative. PFD, p. 79.

In exceptions, DTE Electric states that this disallowance should be rejected. No reply was filed.

The Commission has not adopted the Staff's adjustments to bridge and test year period distribution operations expense (excluding 2018), but rejects the Attorney General's proposed reduction, which was not addressed in her exceptions or replies to exceptions.

iii. Non-Wires Alternative Pilot Expense

DTE Electric proposed a non-wires alternative (NWA) pilot for the purpose of research and analysis of battery storage, interconnection, and management options. The Attorney General disputed the value of the pilot and proposed that DTE Electric await the results of other utilities' pilots. MEC/NRDC/SC testified that DTE Electric should be placing more emphasis on NWAs and suggested several ways to expand the program.

The ALJ recommended approval of the NWA pilot as proposed, finding that the pilot is modest and takes advantage of existing solar generation. PFD, p. 81. She recommended that the

Commission consider MEC/NRDC/SC's proposals once the pilot is completed and the five-year plan is refined. No exceptions were filed. The Commission adopts the findings and recommendations of the ALJ and approves the NWA pilot. As part of the next round of distribution plans, the Commission is eager to understand the results and lessons learned from the NWA pilot, identify screening criteria for determining projects suitable for NWA solutions, and explore opportunities for expansion to engage customers in bringing about system solutions.

iv. Advanced Distribution Management System Expense

The Attorney General opposed the inclusion of any advanced distribution management system (ADMS) cost ($84.3 million), again on grounds that DTE Electric should wait to learn from the mistakes of other utilities and not be an early adopter of this technology, and also argued that the reduction to system average interruption duration index (SAIDI) claimed by the utility is not enough to justify the cost of the technology.

The ALJ recommended rejection of the Attorney General's proposed total disallowance. She found that DTE Electric provided evidence that ADMS is common in the electric utility industry and that DTE Electric's ADMS projects will help address systems "that have reached end-of-life." PFD, p. 83.

In exceptions, the Attorney General argues that this technology is new and unproven, the expense level is excessive, the less than 5% estimated reduction to SAIDI is not enough to justify the spending, and the current system is stable and has not reached the end of its useful life.

In reply, DTE Electric states that this project is necessary and is well underway, and that the current systems are no longer properly supported by the original vendors that supplied them, such that, if they stopped working, the company may not be able to get them functioning again. 4 Tr 758. DTE Electric notes that these systems are necessary to ensure safe and reliable operation of the grid and argues that this investment cannot be deferred. The company asserts that at least 20 utilities are implementing this technology. The company also notes that the Attorney General's witness originally recommended pursuit of the ADMS project. 4 Tr 758-763, 868-871.

The Commission adopts the findings and recommendations of the ALJ. Simply because technology is new does not mean that it should be ignored, or that it will not provide a benefit to ratepayers. The Commission finds this capital expense amount to be reasonable in light of the significant improvements in reliability, integration with distributed resources, and substation outage risk that are offered by ADMS, and the fact that it is becoming commonplace in the industry.

v. System Operating Center Expense

The Attorney General proposed a disallowance of the $111 million cost of modernizing the system operating centers (SOCs), but not until initial briefs. DTE Electric noted that it provided no rebuttal on this issue because the Attorney General did not introduce it during the evidentiary phase of the case. The ALJ recommended rejection of the Attorney General's proposal as untimely. PFD, p. 84.

In exceptions, the Attorney General argues that the ALJ erred. The Attorney General contends that, if she cannot propose a disallowance in her brief that was not actually proposed in her witness's testimony, then the purpose of cross-examination is negated. The Attorney General states that her expert witness discussed this issue at length (without specifying a disallowance). She contends that the company had ample opportunity to respond to the disallowance proposed in the initial brief in its reply brief, exceptions, and replies. The Attorney General maintains that this is not an issue of the shifting of the burden of proof, but rather that a party must be allowed to change, add to, or delete from its position as reflected in its testimony when it arrives at the briefing stage of the case.

In reply, DTE Electric notes that the Attorney General's witness testified "Although updating the two operating centers appears necessary, the cost appears to be rather excessive . . . . I recommend that the Commission direct the Company to make every effort to bring the final cost well within the $111 million." 5 Tr 1635. Thus, DTE Electric contends, the Attorney General supported the SOC effort as long as it was completed within the projected budget, and for that reason the company offered no rebuttal. DTE Electric states that when a party changes position, it requires the presentation of a different set of facts and a new analysis, neither of which was presented by the Attorney General. DTE Electric argues that the Attorney General went from seeming to accept the proposed $111 million to recommending its total disallowance. DTE Electric maintains that the Commission has found that when a specified position comes too late in the process to allow for rebuttal a fair determination of the issue is not possible, and notes that the Commission may not make decisions based on non-record materials. January 11, 2010 order in Case No. U-15768 *et al.,* pp. 37-38; MCL 24.276.

The Commission stresses the need for and importance of this modernization project for system operations from a reliability and resiliency standpoint. 4 Tr 767-771. Turning to the procedural issue, in her exceptions, the Attorney General offers no explanation of why it was possible to discuss the issue generally but impossible to arrive at a proposed disallowance amount until after cross-examination. Indeed, the Attorney General's testimony supports the proposal with the condition that it remain "well within" its projected budget. 5 Tr 1635. In any case, the actual amount of the proposed disallowance was not proposed until after the evidentiary record was closed, meaning that the amount of the disallowance itself was not supported in the record and the utility and other parties had no opportunity to challenge the amount. The Commission agrees with the ALJ and adopts her findings and recommendations.

f. Other Adjustments and Recommendations

The Staff recommended that DTE Electric maintain a 10-year period between 4.8 kilovolt (kV) hardening and any 13.2 kV conversion and the company agreed. PFD, p. 84, n. 155. Soulardarity proposed that DTE Electric focus more immediately on hardening or completely converting the 4.8 kV system in Detroit. The ALJ recommended rejection of Soulardarity's proposal, noting that parts of the 4.8 kV system in Detroit are much older than other parts of the utility's system and that some of the safety concerns raised by Soulardarity are related to residual wiring from the Detroit Public Lighting Department. The ALJ agreed with DTE Electric that the 4.8 kV hardening proposal is economically efficient and that a more complete conversion of the system to 13.2 kV would be expensive and provide limited incremental benefit. PFD, p. 85.

In exceptions, Soulardarity disagrees and argues that the ALJ is dismissing the need for change. Soulardarity contends that there is ample evidence in this record showing that low-income residents of Detroit live with electric service that is less reliable and safe than the service afforded to customers in other areas. *See* Exhibit A-23, Schedule M5, p. 153. Soulardarity contends that DTE Electric's process for identifying service areas in need of reliability improvements adds to the gap in the quality of service by selecting economically rebounding areas for prioritization and conversion, thus leaving low-income areas that are not experiencing economic growth further behind. Soulardarity asserts that these areas are either selected for hardening of the 4.8 kV system or are simply ignored, rather than being eligible for conversion to the 13.2 kV system. Soulardarity argues that withholding investment from areas that lack economic growth results in a self-fulfilling prophecy because economic growth is stifled in areas with unreliable electrical service. Soulardarity argues that this pattern of investment disproportionately affects people of color and low-income ratepayers.

Soulardarity urges the Commission to require DTE Electric to deliver system conversion to all ratepayers. Noting the ALJ's conclusion that hardening the 4.8 kV system is economically efficient because it delivers about 80% of the benefits of an improved system for about 16% of the cost, Soulardarity maintains that the economic efficiency, even if clear, still does not explain why certain ratepayers are only entitled to "be served by infrastructure that is 4/5ths the quality of the infrastructure serving more affluent communities." Soulardarity's exceptions, p. 4. Soulardarity further notes that DTE Electric does not have a plan for providing even the hardening to all areas within the 4.8 kV system, and that the current plan is already 10 years long. 5 Tr 983. Soulardarity urges the Commission to ensure that any rate increase offers all ratepayers reasonable and prudent safety and reliability investments.

In reply, DTE Electric states that it does not consider the income of its customers when making decisions about safety and reliability investments or about what areas require repair or improvement; rather these decisions are based upon the needs and characteristics of the system. 4 Tr 897-898; 5 Tr 958-959. The company states that it is investing heavily in Detroit through the hardening program, the removal of arc wire, and the infrastructure upgrades program. 4 Tr 743-745, 752-753, 897-900. DTE Electric argues that the hardening will provide about 80% of the benefits of improvement for about 16% of the cost to convert to 13.2 kV, that is, a cost of $660 million instead of $4.2 billion. 4 Tr 730. DTE Electric claims that complete conversion would result in rate shock but provide a limited incremental benefit, while also requiring larger-scale outages. DTE Electric further argues that Soulardarity's position is unlawful, in that rates are set to recover the amount that the utility needs for a return of and on its investment in providing service. Finally, DTE Electric maintains that areas in the Detroit system that are not addressed by the hardening or infrastructure programs in this rate case will still be addressed, but it will be outside of the five-year time period addressed in the utility's filing in this case.

Soulardarity makes some important points about the importance of ensuring safe, reliable service for all ratepayers. The 4.8 kV system is not limited to the city of Detroit, and extends to the suburbs and the Thumb area served by DTE Electric. It is an aging system that will be very expensive to completely replace. It is not feasible to do this all at once. DTE Electric has developed a risk-based approach to convert certain areas to 13.2 kV and harden other parts of the existing 4.8 kV system to ensure safer, more reliable conditions until the full conversion can take place. It is important to remember that the Commission must consider the interests of all ratepayers and the cost burden imposed by each expenditure decision. All expenditures must be reasonable and prudent, and, as the ALJ explains, it is currently impossible to find that the cost of conversion of the entire system to 13.2 kV is reasonable and prudent in light of the fact that 80% of the service quality improvement that can be expected from conversion can be obtained for about 16% of the cost through hardening. The Commission is working to improve conditions in Detroit through its decisions on system hardening and tree trimming,[6] as well as the investigations related to billing and the need to address the presence of arc wire in the city. As Soulardarity points out, all ratepayers should be subject only to rates that result in reasonable and prudent investments in safety and reliability. The Commission adopts the findings and recommendations of the ALJ.

[6] The Commission is requiring DTE Electric to provide regular reporting on tree trimming efforts in the city of Detroit and in the Caniff Service Center area.

4. Advanced Metering Infrastructure

a. 3G to 4G Upgrade

The Staff originally proposed disallowances related to the 3G to 4G upgrade for the advanced metering infrastructure (AMI) equipment, meant to be used only if the Commission rejected the Staff's distribution expense adjustments. The Staff proposed a $9.6 million disallowance associated with 300 additional 4G cellular relays, because the AMI system is functional with the 3,000 that were initially installed and the company's meter read rate through 2017 was 98.51%. Having made the Staff's distribution expense adjustments, the ALJ found that these reductions had already been incorporated into rate base. PFD, p. 85.

In exceptions, DTE Electric argues that the proposed disallowance should be rejected. DTE Electric's exceptions, p. 23, n. 12.

In its reply, DTE Electric describes the issue, in the event that the Commission reaches it. DTE Electric argues that the additional 300 relays would allow the company to strengthen the mesh network in weak mesh areas and increase the meter read rate to 99.5% which would be comparable to Consumers' meter read rate. DTE Electric posits that it is important to charge customers for their actual usage, and that a strong mesh network also supports outage restoration. 8 Tr 3965-3967. The utility also argues that the Staff miscalculated the disallowance which should be $2.37 million (300 relays times $7,900 cost per relay), not $9.6 million. 8 Tr 3967.

The Staff filed no reply.

The Commission has not adopted the Staff's adjustments to the bridge and test year periods (excluding 2018) for distribution operations expense. However, the Commission agrees with the Staff and the ALJ and adopts the proposed $9.6 million disallowance associated with the 300 additional 4G relays. As the Staff notes, DTE Electric's meter read rate is high, well above the

85% required by the Commission's Service Quality and Reliability Standards for Electric Distribution Systems, Mich Admin Code, R 460.724(d). The utility has been able to achieve this level of meter reads with 3,000 relays, and the Commission agrees with the Staff that the additional 300 relays are an unnecessary expense. The Staff's proposed disallowance includes the cost of labor (whereas the company's proposed number in replies to exceptions does not). The Commission approves this disallowance. In DTE Electric's last rate case, the Commission expressed concern over the conversion to 4G given the plans of the telecommunications industry to move to 5G and the potential for stranded investments due to technology obsolescence. April 2018 order, p. 13. The Commission stresses the importance for DTE Electric to strategically integrate and sequence its technology enhancements to support grid modernization efforts. With increased digitalization, this attention to technology is essential to avoid unnecessary costs and ensure ratepayer benefits. As discussed in the November 21, 2018 order in Case No. U-20147, pp. 34-39, addressing priorities for the next round of distribution plans, the Commission expects an increased focus on visibility around information technology components.

Apparently related to the topic of the 3G to 4G upgrade, in exceptions RCG contends that DTE Electric's AMI mesh network was poorly designed and is failing. RCG urges the Commission to institute a show cause case into whether the system should be redesigned with the associated cost assigned to shareholders. RCG proposes that the Commission eliminate all projected capital and O&M costs associated with the AMI mesh network and initiate an investigation.

In reply, DTE Electric contends that RCG has provided no basis for this argument. The Commission agrees with the utility and rejects RCG's exception, which appears to have no basis in the record evidence and is unsupported by any legal argument.

b. Opt-Out Customers

In the December 20, 2018 order in Case No. U-20084, the Commission approved a settlement agreement addressing purportedly non-transmitting meters that were actually transmitting. Aspects of the settlement included replacement of meters and refund of opt-out fees. In the instant case, RCG argued that rates should be adjusted for disallowances associated with the settlement. Noting that the settlement agreement was entered into and approved after the closing of the record in this matter, the ALJ found that any rate adjustments should be addressed in DTE Electric's next rate case. PFD, p. 87.

In exceptions, RCG contends that rates should be adjusted in line with the settlement agreement in Case No. U-20084, and that the Commission should ensure that the settlement agreement is enforced.

The December 20, 2018 order in Case No. U-20084 was issued after the close of the record in this matter and played no role in the evidentiary portion of this case. Any rate adjustments or other issues related to that order should be addressed in DTE Electric's next rate case. The Commission adopts the findings and recommendations of the ALJ.

RCG also proposed that the opt-out charge for customers who elect not to have an AMI transmitting meter should be reduced or eliminated. Noting that RCG failed to introduce new evidence or arguments (which have been heard repeatedly) and the fact that the Commission ruled on this issue in Case No. U-18014 and was affirmed on appeal, the ALJ recommended rejection of RCG's proposal. PFD, p. 88.

RCG excepted, arguing that AMI opt-out surcharges should be eliminated or reduced.

DTE Electric replied, noting Commission precedent and arguing that RCG should be cognizant of the relevant law on this issue.

The Commission adopts the findings and recommendations of the ALJ. *In re Application of DTE Electric Company to Increase Rates*, unpublished per curiam opinion of the Court of Appeals, issued October 25, 2018 (Docket No. 338378); *In re Application of Detroit Edison to implement opt-out program*, unpublished per curiam opinion of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728 and 316781), lv den 499 Mich 868 (2016), reh den 499 Mich 972 (2016); *Detroit Edison Co v Stenman*, 311 Mich App 367, 382; 875 NW2d 767 (2015); *Attorney General v Pub Serv Comm*, unpublished per curiam opinion of the Court of Appeals, issued April 30, 2015 (Docket No. 317456).

5. Demand Side Management Programs

DTE Electric proposed spending about $30.5 million on demand side management (DSM) programs, including on programmable communicating thermostats (PCTs). The Staff recommended a total disallowance of $9.593 million based on the very low participation in these programs. The Staff noted that in the January 31, 2017 order in Case No. U-18014 the Commission approved funding for 10,000 PCTs, and that, as of September 30, 2018, only 3,000 customers had signed up (and the company's original goal was 10,000 customers per year for five years). Noting that DTE Electric is falling far short of its enrollment goals, the Staff recommended no additional amounts for PCTs, and that the utility prioritize marketing and outreach for DSM programs. 8 Tr 4142-4143. The Staff also noted that additional expenditures would still be recoverable through the demand response (DR) reconciliation process approved in Case No. U-18369.

The ALJ recommended adoption of the Staff's proposed $9.593 disallowance for this expense category. She pointed out that, in addition to low enrollment, only 65% of enrolled customers have actually installed the PCT. PFD, p. 92.

In exceptions, DTE Electric posits that there is confusion over the funding requests. DTE Electric states that it is requesting $6.2 million for January 2018 through April 2019 in order to complete the enrollment of the original 10,000 customers (approved in Case No. U-18014), and it requests an additional $3.4 million for the test year to enroll an additional 7,000 customers by the summer of 2020. Exhibit S-21. The company states that it has historical expenses of $2.1 million as of December 31, 2017. It requests an additional $6.1 million for the distributed energy resource management system that runs the PCT program, which, it argues, is necessary no matter how many customers are enrolled. DTE Electric posits that all of the requested funding is justified by the progress and success shown thus far. DTE Electric notes that it had enrolled 3,900 customers by November 12, 2018, and commits to achieving 17,000 enrollments by the summer of 2020. 3 Tr 386-387. DTE Electric states that it will be launching new campaigns to increase enrollment, and, in the alternative, "the Commission should at least approve $6.2 million to complete the initial 10,000 customer enrollment." DTE Electric's exceptions, p. 27.

In reply, the Staff voices its doubts about the company's commitment to this program and urges the Commission to adopt the proposed $9.6 million disallowance.

The Commission has its doubts as well and adopts the findings and recommendations of the ALJ. In the April 2018 order, p. 22, the Commission denied a request for funding to purchase 25,000 PCTs, finding that the company had not yet shown initial success from the 2017 rate case order providing funding. As the ALJ points out, not only is enrollment low but usage of the PCTs by enrolled customers is low as well. The Commission denies the incremental $6.2 million to enroll the original 10,000 customers (for which funding has already been approved), and the $3.4 million for the test year. The Commission will not consider further expenditure until DTE Electric completes enrollment of the first 10,000 customers and demonstrates some measure of success with the program.

6. Information Technology Expense

a. Corporate Applications – ConnectUs Phase 4 Project Expense

The Staff proposed a complete disallowance of the ConnectUs Phase 4 project on grounds that email is a reasonable means of communication that can also provide enhanced collaboration. 8 Tr 4149; Exhibit A-12. Schedule B5.7.1. The ALJ recommended rejection of the disallowance proposal. She noted that this expense item was previously called Video Collaboration Program Phases 3 and 4, that the renaming introduced confusion, and that the expense was previously approved in the 2018 orders. PFD, pp. 93-94. No exceptions were filed. The Commission adopts the findings and recommendations of the ALJ.

b. Customer Service – Customer Digital Channels (MSA) Sustainment Project

The Staff proposed a disallowance of all capital expense for the bridge period and the test year, amounting to $3.195 million, for the Customer Digital Channels (MSA) Sustainment project. Exhibit S-12.3, p. 9; 8 Tr 4150; Exhibit A-12, Schedule B5.7.1. Sustainment involves the addition of "disk storage to account for growth, additional hardware for memory and performance enhancement, and end-of-life replacements." 5 Tr 1404; DTE Electric's exceptions, p. 30, n. 15. The Staff objected to the fact that DTE Electric's projections were based on historical spending rather than on specific, planned spending. The Staff opined that information technology (IT) is changing too rapidly for expenses to be based on what was historically spent. 8 Tr 4150. The ALJ recommended adoption of the proposed disallowance, agreeing with the Staff that historical IT spending is not a good indicator of projected spending in this fast-paced category. PFD, p. 95.

In exceptions, DTE Electric states that this project is intended to address an existing backlog of necessary kiosk, web, mobile, and interactive voice response (IVR) enhancements which will improve company response times and payment methods for customers. 5 Tr 1408-1409. DTE Electric contends that it prioritizes actual spending (and not just historical), which is also constantly updated.

In reply, the Staff reiterates its position that "given the rapid pace of advancement and cost decreases in the [IT] field it is inappropriate to base an unknown future cost on a historical spend." Staff's replies to exceptions, p. 10.

The Commission adopts the findings and recommendations of the ALJ. While DTE Electric provided some modicum of information on what the expense was for, it still based the amount on historical spending, in an area that is universally recognized to be changing rapidly in ways that should be relatively easy to demonstrate. The introduction of new technologies may add to costs, but slightly less new technologies also continue to decrease in cost as they undergo widespread adoption. DTE Electric may wish to provide more specific information on planned costs in its next rate case for this category of expense. The reporting requirements discussed below should help with this effort.

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

The Staff proposed a disallowance of approximately $3.1 million for the bridge period and test year for these expense categories in total, arguing that they are really still in the planning phase and not ready for recovery from ratepayers or a return on investment. Exhibits S-12.2, S-12.3; 8 Tr 4151; Exhibit A-12, Schedule B5.7.3. The Staff also noted that DTE Electric's discovery responses requested amounts far below what was requested in its original filings. The ALJ agreed with the Staff, finding that DTE Electric had included these projected amounts as placeholders without a finalized spending plan. PFD, p. 97. The ALJ noted that reasonable and prudent amounts could still be recovered in the next rate case.

In exceptions, DTE Electric combined the exceptions addressing this IT category with its exceptions addressing the next IT category. Regarding this category the company stated:

> Staff also grouped the Work Management Sustainment (Maximo/ESri/Service Suite), Fuel Supply Sustainment, GenOps Business Sustain, IT FosGen Business Sustain, and Fermi – Nuclear Gen Sustain projects together, and generically proposed a partial disallowance based on the assertion that the Company-provided audit responses include a total expected cost that falls below the amount originally indicated, so a disallowance should be made for the suggested surplus in each project.

DTE Electric's exceptions, p. 31.

The Commission adopts the findings and recommendations of the ALJ. When discovery results in a change to the original filing, it undermines the credibility of the original filing and the notion of any certainty with regard to the actual planned spend. The problems associated with the IT expense categories in this case are further discussed in the next two sections of this order.

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

The Staff proposed a disallowance of approximately $6.6 million for the bridge and test year periods from this expense category based on the uncertainty associated with "emergent" needs as characterized by the company. 8 Tr 4149-4150; Exhibits S-12.2, S-12.3, p. 8; Exhibits A-12, Schedule B5.7.2 and 5.7.5. The ALJ agreed with the Staff "in light of the uncertainty about the need for the projects, coupled with the unknown cost of emergent items." PFD, p. 98.

In exceptions, DTE Electric argues that the need for the projects is known and it is only the final scope that is not yet finalized. 5 Tr 1402-1404. The company contends that the IT Business Planning and Development Sustainment project also has a backlog of requested upgrades and enhancements that need to be achieved and that are prioritized on an ongoing basis. DTE Electric states that it is simply showing flexibility by constantly updating this list, sometimes in response to interactions with the Staff, and that it is efficient to forecast some amounts in the aggregate.

As for other projects, DTE Electric states:

> The Innovations Project Management Office ("iPMO") has been formed to govern the emergent initiatives, experiments and projects represented within this project. The investments resulting from this project constitute prioritized work on a variety of programs that are known, sequenced and approved for investment (5T 1404-1405). Mr. Griffin also explained the following technology trends that are in the pipeline and included in 2018 Emergent: Robotic Process Automation; Drones; Industrial Internet of Things; Augmented Reality; and Artificial Intelligence and Machine Learning. (5T 1405-1407; Exhibit A-38, Schedule BB-2).
>
> The coDE Sustainment project presents another unique scenario, this time involving DTE's only in-house custom IT development staff, which operates from a prioritized backlog of requested upgrades and feature enhancements reviewed on an ongoing basis (again, sometimes due to interaction with Staff) throughout both the bridge and test periods. Like the previous categories, these investments are not uncertain. Instead, the Company is working from a known backlog where the only unknown is exactly which of the programs will be prioritized the highest based on ongoing input from customers and the Commission or its Staff (5 T 1407-1408).

DTE Electric's exceptions, pp. 30-31. DTE Electric states that its witness presented a representative set of investments rather than a detailed breakdown for each project, focusing on the most significant investments, because it is impractical for the company to produce the "thousands of pages of documentation regarding each enhancement that makes up the backlog especially since none of the portfolio's backlogs will be completely exhausted in a single rate case period." 5 Tr 1410-1411. The company contends that the costs are in fact known and the only unknown is how the projects will be prioritized, and that this area of expense involves continually-evolving backlogs of work.

The Commission adopts the findings and recommendations of the ALJ. While the Commission acknowledges that there may be cost categories for which it makes sense to present representative investments, those representative investments must be supported by a demonstration of the need for the investment (what is its priority and why) and the cost of the investment (with a degree of certainty that allows the Commission to make a reasoned decision). Additionally, it must be shown precisely how the representative investments relate to the totality of investments that are actually proposed. DTE Electric did not accomplish this with its filings in this case. As the Staff points out, these cost categories were so uncertain that they appear more in the light of contingency than real costs. The Commission adopts the Staff's proposed partial disallowance, which allows for recovery of only the costs spent to date. 8 Tr 4150. It is hoped that the IT filing requirements, discussed in the next section, will help alleviate the problems caused by this knowledge gap.

e. Information Technology Reporting

The Staff requested that several categories of specific additional information be included in DTE Electric's next rate case filing addressing IT projects, which would provide significantly more detail and analysis for the parties and the Commission. DTE Electric agreed, with the understanding that the reporting would apply only to projects costing $500,000 or more; however, the utility objected to providing over or under budget amounts of 20% or more for projects, or descriptions of projects that are not completed. PFD, p. 99. The ALJ agreed with the Staff and recommended adoption of all of the proposed reporting requirements. Finding that the fast pace of change in the IT arena presents a new frontier in spending projections, the ALJ found this to be an important spending category in need of greater transparency, particularly where projects that have been approved are later cancelled or abandoned. PFD, p. 101.

In exceptions, DTE Electric explains that it continues to agree to the reporting requirements as long as the $500,000 threshold is adopted and the reporting is limited to projects for which the company is seeking additional funding. 5 Tr 1412-1417. DTE Electric objects to the adoption of a filing requirement for past expenditures (where it is not seeking additional recovery) as an exercise in hindsight, and argues that there is no legal basis for reconciling established rates. DTE Electric contends that only in cases where it is seeking additional funding is the progress and the cost of the project relevant to the revenue requirement. No reply was filed.

IT programs have not fared well in this rate case. It behooves the utility to provide the level of information that can result in approval of IT capital expenditures. The Commission adopts the additional IT reporting requirements that were agreed upon by DTE Electric and the Staff. These requirements are as follows:

A. Future IT project-level detail will include a breakdown of both the O&M and capital costs. O&M costs will be broken down into two or three sub-categories.

B. For each IT project with a value threshold of $500,000 or more the company will submit a project approval document after the project preliminary analysis phase that includes:

1. A brief synopsis describing the project.

2. The project approval date.

3. The incurred O&M expenditures to date.

4. The total project estimated O&M and capital cost through project implementation.

5. Any necessary approvals by the company's management with appropriate expenditure approval authorization (per documented company policy).

6. Any approved change management documentation if the total project estimate grows by greater than 10% or $500,000 (whichever is greater).

7. For IT projects over $500,000, the company will include as an exhibit a copy of the written, PowerPoint, or other media presentation that the company's technical staff used to present the project justification and alternatives considered by company senior management.

8. Analysis that shows the company considered cloud computing alternatives in IT project expense requests over $100,000 excluding cyber security or transmission control IT projects.

9. The company will provide a breakdown of any IT programs that were approved in its previous rate case that were not completed or were 20% above or below the approved project amount with an explanation of why the project was not completed or why it was off budget, only for projects that meet the $500,000 threshold and where additional recovery is being sought in the relevant rate case.

See 8 Tr 4151-4152; 5 Tr 1412-1417.

7. Corporate Staff Group Capital Expense

Corporate Staff Group (CSG) provides administrative and general services to DTE Energy companies. The Attorney General proposed two disallowances from this expense category.

First, the Attorney General proposed a $17.052 million reduction based on the fact that spending in the first eight months of 2018 was below projections. 5 Tr 1640-1641. Finding that DTE Electric had not responded to this argument, the ALJ recommended adoption of the disallowance. PFD, p. 102.

In exceptions, DTE Electric contends that the lack of rebuttal testimony on this issue is not a valid basis for accepting the proposed disallowance which arises simply from the unsupported opinion of the Attorney General's witness. DTE Electric argues that it also provided many pages of testimony on the need for the CSG expense and identified particular projects and costs. 7 Tr 3314-3321. DTE Electric urges the Commission not to rely on speculation that it will not spend what it forecasts in the face of evidence supporting the need for the expense.

In reply, the Attorney General contends that the company's spending is far below what was projected and its exceptions provided no new argument.

The Commission adopts the finding and recommendations of the ALJ. The Attorney General demonstrated that spending was well below projections and DTE Electric, on rebuttal, did not provide any convincing evidence to the contrary. The Commission approves the $17.052 million expense reduction to this category.

Second, the HQ Energy Center is DTE Electric's proposal to construct a new energy center to supply steam and chilled water to the company's headquarters. The company seeks inclusion in rate base of $32.5 million for the project. The Attorney General proposed that the entire cost of the HQ Energy Center be disallowed because DTE Electric failed to attempt to negotiate with Detroit Thermal, LLC (Detroit Thermal) for a lower steam rate or for the repair of leaks.

The ALJ recommended rejection of the Attorney General's argument, finding that the new facility will address the issues of cost and repairs with respect to steam, and will also replace the chilled water system which has reached the end of its life. PFD, p. 104.

In exceptions, the Attorney General continues to recommend the disallowance, arguing that it is needlessly expensive for the company to construct and own its own steam and chilled water system. She contends that DTE Electric should have negotiated with Detroit Thermal, and should have done more to investigate the leaks and repair issues.

In reply, DTE Electric points out that Detroit Thermal has increased prices by about 5% annually since 2013 and its system needs to be upgraded, and the utility needs a new chilled water system. 7 Tr 3318-3319. The company contends that the HQ Energy Center will provide an energy savings of about 2.5 million kilowatt-hours (kWh) per year and will allow DTE Electric to better control its steam costs. 7 Tr 3319-3320.

The Commission adopts the findings and recommendations of the ALJ. DTE Electric provided evidence showing that the HQ Energy Center will provide needed steam and chilled water to the utility at a reasonable cost, and will address the issues the company has been having with steam supplied from Detroit Thermal. The Attorney General provided no evidence refuting DTE Electric's showing that the chilled water system is at the end of its life, that Detroit Thermal's prices have been rising, or that the company can better control its steam costs by owning and operating its own system. 7 Tr 3318-3320. After removal of the requested $4.5 million in contingency costs, the company seeks approval of a capital investment of $28 million. Even before removal of the contingency amount, the NPVRR for the HQ Energy Center project showed about $50 million, compared to an NPVRR of about $54.1 million for the status quo (assuming continued steam price increases). The Commission finds the capital investment to be reasonable and prudent.

B. Working Capital

1. Reduced Emissions Fuel Credit

The Attorney General argued that the reduced emissions fuel tax credit is likely to be extended and thus DTE Electric's working capital should be adjusted by $21.9 million. The ALJ was not persuaded that the credit was likely to be extended or that, if extended, would apply to the company's existing facilities as opposed to only new facilities. PFD, p. 105. No exceptions were filed and the Commission adopts the findings and recommendations of the ALJ.

2. Short-Term Investments Recorded as Cash

The ALJ agreed with DTE Electric that $3.5 million in loans to affiliates was not included in working capital and thus did not (as the Attorney General argued) need to be removed from working capital. PFD, p. 106. No exceptions were filed and the Commission adopts the findings and recommendations of the ALJ.

3. Prepaid Pension Asset

In its exceptions, ABATE identified an issue that the PFD did not address. PFD, pp. 104-106. ABATE contends that DTE Electric should not be allowed to include a prepaid pension asset in rate base. ABATE states that a prepaid pension asset is the difference between the minimum funding contributions required under the Employee Retirement Income Security Act of 1974

(ERISA) and the actual funding contribution made by the utility, which, in this case, amounts to an additional $105 million that DTE Electric proposes to include in rate base. ABATE argues that this amount raises the company's revenue deficiency by $7.5 million (at the proposed overall rate of return), and disallowance of the total prepaid pension asset will lower the revenue deficiency by $60.5 million. 7 Tr 2923-2925. ABATE maintains that this prepaid expense should only be allowed in rate base if the utility proves that the asset is a reasonable and prudent investment and has the effect of either lowering the utility's overall pension cost of service or supports the integrity of the pension trust, or both. 7 Tr 2921. ABATE states that Indiana, Illinois, and New Mexico use similar criteria.

ABATE further argues that the Commission adopted a test for inclusion of such an asset in rate base in the April 28, 2005 order in Case Nos. U-13898 *et al.*, p. 32. In that order, ABATE argues, the Commission approved a prepaid pension asset because the asset was not an interest-earning utility asset, and the utility in that case had a negative pension expense (which gave rise to the creation of the prepaid asset). ABATE asserts that DTE Electric does not pass this test because its pension asset is a positive $68 million.

In reply, DTE Electric contends that, in light of the working capital figure recommended by the ALJ, she must have implicitly rejected ABATE's argument without discussion. DTE Electric goes on to argue that the prepaid pension asset is a reasonable and prudent investment that helps reduce pension costs by funding the pension trust. The company states that additional annual contributions to the trust do not result in overfunding the trust, and that, for the test year, pension trust assets will be $479.5 million less than the pension liability. 7 Tr 3353-3354. DTE Electric states that it has adopted a strategy of going beyond the minimum ERISA requirements "to realize the advantage of compounded returns on investments," and to achieve tax savings. DTE Electric's replies to exceptions, p. 24; 7 Tr 3355. DTE Electric points out that the pension costs included in the revenue requirement approved for 2017 and 2018 do not reflect the additional funding, "so the benefits of the Company's pension funding strategy have already been passed through to customers through reduced revenue requirements." DTE Electric's replies to exceptions, p. 25; 7 Tr 3356. The company argues that the return on assets offsets other components of pension costs and higher pension balances bring higher returns. The company states that if rate base is reduced by the average prepaid pension asset balance of $796.5 million, the utility's total projected pension costs would increase by $58.1 million due to the loss of the return at 7.30%. 7 Tr 3357; Exhibit A-36, Schedule Z2. DTE Electric points out that it can deduct the contributions made to the pension trusts from income tax, and, again, if rate base was reduced by the average prepaid pension asset balance, then the company's deferred income tax liability balance would be reduced by $207.1 million and the revenue requirement would be increased by $14.9 million. The total impact, according to DTE Electric would be an increase in pension cost of $73 to $81.5 million, which exceeds the $57.3 million in the revenue requirement in this case arising from including the prepaid pension asset in rate base (based on the company's overall pre-tax rate of return). DTE Electric's replies to exceptions, pp. 25-26. Thus, DTE Electric argues that ABATE's proposal, if accepted, would require an increase in the company's net pension costs of about $15.8 million, to $24.3 million. 7 Tr 3357-3358.

In its reply, ABATE contends that the prepaid pension asset "has not been proven to have been funded by ratepayer investor capital, and therefore DTE has not proven that it is reasonable for it to earn a rate of return on this asset from retail customers." ABATE's replies to exceptions, pp. 8-9.

The Commission approves the prepaid pension asset for working capital treatment in this case. Prepaid pension assets are costs that have been incurred but have not been recovered from ratepayers and thus belong in working capital. ABATE provided no evidence to show that the company did not take this amount out of its own pocket to add to the pension fund – and the fund is ultimately the responsibility of ratepayers. However, in its next rate case, DTE Electric is directed to provide additional evidence on this cost demonstrating that the prepaid pension asset should be included in working capital, including the source of the funding of the prepaid pension asset.

C. Rate Base Summary

Based on the adjustments set forth in this order, DTE Electric's rate base is $17,058,834,000 for the test year, on a total company basis. This is comprised of $15,580,427,000 in net plant and an allowance for working capital of $1,478,407,000.

IV. CAPITAL STRUCTURE AND RATE OF RETURN

DTE Electric requested an ROE of 10.50%, with an overall, after-tax rate of return (ROR) of 5.72%. The company is also requesting a permanent capital structure of approximately 51% equity and 49% debt. The company projected average rate base for the test year is approximately $17.2 billion, which includes an equity base of approximately $6.7 billion. Exhibit A-14, Schedule D1.

The ALJ recommended an after-tax ROR of 5.48%. PFD, p. 130. The company excepts, asserting that the company should have a weighted, after-tax ROR of 5.72%. DTE Electric's exceptions, p. 36. The Attorney General replies that the company's after-tax ROR should be 5.33%. Attorney General's replies to exceptions, p. 14.

A. Capital Structure

1. Debt and Equity Balances

DTE Electric proposed a long-term debt balance of $6.433 billion and a common equity balance of $6.695 billion, which constituted approximately 51% of the permanent capital structure. The company's proposal would modify the 50/50 capital structure approved in the 2018 orders. The company argued that an equity ratio of 51% is below the peer average and claimed that "[t]he increased equity level is especially important given the significant capital investments the Company is making over the next 5 years to maintain and improve the electric infrastructure to benefit our customers." 5 Tr 1041.

DTE Electric also explained that the adjustment is necessary to increase "the financial soundness and creditworthiness of the Company at a time when it is facing the material, negative impacts of the Tax Cuts and Jobs Act [TCJA] of 2017." *Id*. According to the company, because of the lower tax rate and the loss of bonus depreciation, utilities may lose some of their cash flow attributed to deferred taxes. DTE Electric argued that the loss of cash flow decreases the Funds From Operations (FFO) to debt ratio, "which is a key metric that credit rating agencies use to measure credit quality." DTE Electric's initial brief, p. 47. The company claimed that Moody's Investors Service (Moody's) downgraded the outlook for the entire regulated utilities sector to negative as a result of lower cash flows and higher debt levels because of the TCJA. Therefore, in order to ensure that DTE Electric has access to credit markets and an ability to raise capital at reasonable terms and rates, the company asserted that it is important to strengthen the company's capital structure by increasing equity to 51%. The Staff agreed with DTE Electric's proposed equity balance.

The Attorney General argued that DTE Electric's testimony and exhibits fail to support an increase in common equity. She asserted that the company's proposed common equity ratio of 51% is not below peer average; rather, on June 30, 2018, the peer company average was 47.60%. The Attorney General also noted that the company admitted that neither DTE Electric nor DTE Gas have had their credit rating downgraded as a result of the TCJA and that there is no indication that this will occur. She stated that if DTE Electric is permitted to adopt a 51% common equity ratio, it "would unnecessarily increase the revenue requirement by approximately $11 million." Attorney General's initial brief, p. 92. Instead, the Attorney General recommended that the company's capital structure be rebalanced to 50/50 debt to equity by adding $131 million of common equity to long-term debt.

ABATE also disputed DTE Electric's claim that its common equity ratio must be increased. According to ABATE, the company does not have an increased risk profile and its ratings or outlook have not been affected by tax reform. Rather, ABATE stated, "based on the substantial increase in DTE Electric's forecasted dividend payments to its parent company, it is reasonable to conclude that the proposed increase in its common equity ratio is a means to provide cash to shareholders rather than stabilize the financial well-being of the utility." 7 Tr 2970. Therefore, ABATE recommended that DTE Electric's request to increase its common equity ratio should be rejected. RCG agreed.

In reply to the Attorney General, DTE Electric asserted that she incorrectly used holding company data to establish the peer company average. Because DTE Electric is not a holding company, the company argued that it should not be compared with other holding companies and, instead, should be compared with other utilities, whose average common equity ratio as of June 30, 2018, was 51.60%.

The ALJ agreed with the Attorney General and ABATE that DTE Electric failed to provide testimony and exhibits to support an increase in its common equity ratio. She found unpersuasive the company's claim that it must strengthen the equity component of its capital structure because of tax reform changes and because the utility sector had received a downgraded outlook by credit rating agencies. The ALJ noted that, "as of the close of the record in this case, the TCJA had been in effect for almost a year, with no discernable impact on the company or its strong credit ratings." PFD, p. 115. In addition, she stated that DTE Electric did not effectively rebut ABATE's position that the purpose of the company's proposed 51% common equity ratio is to increase its dividends by 2020. Therefore, she recommended that the Commission reject the company's proposal to increase its common equity ratio.

DTE Electric excepts, arguing that an equity ratio of 51% is important to enhance its credit quality and financial soundness, noting that capital structure determines a company's access to credit markets and ability to raise capital at reasonable rates. DTE Electric explains that if it is unable to raise adequate capital, it will be unable to invest in the equipment and systems necessary to ensure efficient, reliable, and safe electric service for its customers. DTE Electric's exceptions, p. 37. Because of the impacts of the TCJA and the significant capital investments the company plans to make over the next five years to maintain and improve its electric infrastructure, DTE Electric argues that conditions have sufficiently changed to warrant an increase to the company's common equity ratio. The company references the fact that it will be financing and funding $4 billion of electric capital expenditures for the 27-month period of January 2018 through April 2020. Finally, DTE Electric reiterates that its proposed equity ratio is lower than the peer group average and that the TCJA has resulted in negative pressure on the company's financial metrics, which will likely affect its credit rating.

RCG alleges that the purpose of the company's proposed common equity ratio is to bolster and support DTE Energy's consolidated holding company structure. For this reason, RCG requests that DTE Electric's proposed common equity ratio be rejected because it "constitutes an overly rich and expensive ratio." RCG's exceptions, p. 10.

In reply, DTE Electric asserts that RCG provided no discussion of its exception.

On page 17 of her replies to exceptions, the Attorney General reiterates that DTE Electric "failed to present persuasive evidence that the TCJA has had or will have a negative impact on the Company's credit rating or financial outlook."

ABATE replies that its witness's testimony confirmed that the TCJA had no adverse impacts on credit metrics or on DTE Electric's credit rating. Additionally, regarding DTE Electric's requested increase in its common equity ratio, ABATE reasserts that the company is "projecting to increase its dividends to its parent company," which "does not support financial stability or financial integrity." ABATE's replies to exceptions, pp. 2-3.

The Commission adopts the findings and recommendations of the ALJ and approves a permanent capital structure of 50/50 debt and equity. The Commission agrees with the ALJ that the risks identified by DTE Electric are not new to this utility, and that the economy of southeast Michigan has improved dramatically in the last decade, thereby lessening many of those same risks. In addition, the Commission agrees with the ALJ that the TCJA has been in effect for more than a year and there has been no noticeable effect on DTE Electric, and the company admitted that its credit rating is unchanged. While the Commission is aware that the utility will need to continue investing in its infrastructure to provide safe and reliable electric service to its customers, the Commission is confident that DTE Electric can attract the capital it needs to continue such investments with a balanced capital structure as it has had in the past. The Commission agrees with the ALJ that conditions have not changed to such a degree as to warrant a departure from a balanced equity ratio at this time.

2. Accumulated Deferred Income Tax

The company stated that the "TCJA also results in DTE Electric's accumulated deferred income tax ('ADIT') balances exceeding its future tax liability, so the Company proposes to credit these excess ADIT balances back to customers beginning with this case . . . ." DTE Electric's initial brief, p. 48. According to the company, the new corporate tax rate reduced the deferred tax balance by $1.4 billion and a corresponding deferred tax regulatory liability was created. DTE Electric claimed that $0.1 billion relates to non-base-rate surcharges and, therefore, $1.3 billion in deferred tax regulatory liability must be addressed in this case.

The company explained that the $1.3 billion in excess deferred taxes has three components: (1) the protected plant balance, which is the "excess deferred taxes related to the cumulative difference between accelerated tax depreciation and book depreciation," and which, pursuant to the TCJA, must be returned to customers using the Average Rate Assumption Method; (2) the non-protected plant balance, which is amortized using a 23-year straight-line method based on an estimate of the remaining life of the plant assets; and (3) the non-plant balance, which is amortized using a 14-year straight-line method based on the largest cumulative timing difference reflected in the balance. 5 Tr 1541-1542. DTE Electric proposed that amortization of the tax regulatory liability should begin May 1, 2019. Finally, the company contended that the projected test year amortization of $54.9 million should reduce federal income tax expense. Exhibit A-13, Schedule C8, p. 2.

The Staff stated that DTE Electric "provided final amounts for the re-measurement of deferred taxes. The result is a net increase in the projected test period amortization of $411,000 from the preliminary amount reflected in the Company's initial filing." 8 Tr 4019-4020. The company did not dispute the Staff's revised deferred tax amount.

ABATE noted that DTE Electric plans to retire its Tier 2 units and Belle River unit earlier than scheduled, and as a result, the company claimed that it must increase tariff rates to recover the accelerated depreciation expense. ABATE contended that DTE Electric's proposed accelerated recovery of the depreciation expense and the company's proposed customer charge for the construction-period carrying costs on the Blue Water Energy Center (BWEC) will increase the test year cost of service by $120.779 million. To address the sizable increase in tariff rates, ABATE proposed a regulatory plan, which includes:

> a faster amortization of the unprotected excess ADIT to offset the test year cost increases for DTE's proposed coal units accelerated depreciation expense recovery and to charge customers a current AFUDC [allowance for funds used during construction] return on the not-yet-in-service BWEC. ABATE's position is that the available unprotected excess ADIT should be credited back to customers faster than that proposed by DTE so as to offset these extraordinary cost increases which DTE seeks to recover in its proposed increase.

ABATE's initial brief, pp. 17-18. ABATE asserted that Table 2 set forth in testimony shows that its proposed $245.9 million annual amortization of excess ADIT reduces DTE Electric's proposed test year cost of service by $171.6 million. 7 Tr 2905-2906. ABATE also explained that the net impact of its regulatory plan on DTE Electric's cash flow is neutral because the accelerated recovery of the unamortized costs will significantly increase the company's cash flow, while a faster amortization period for the unprotected excess ADIT will correspondingly reduce cash flow. ABATE's initial brief, p. 19.

Kroger supported ABATE's regulatory plan with one condition: "The amortization of the excess ADIT should be allocated to customers consistent with the allocation of costs for the underlying assets which gave rise to the excess ADIT." Kroger's initial brief, p. 11. Similarly, MEC/NRDC/SC agreed that ABATE's regulatory plan should be approved with one qualification: "The accelerated return of excess ADIT to customer classes should be allocated proportionally to the allocation of rate base to the customer classes – rather than being used to offset the allocation of production-related depreciation expense." MEC/NRDC/SC's reply brief, p. 45. MEC/NRDC/SC explained that the purpose of this condition is to preserve the benefits of the accelerated ADIT amortization for residential ratepayers.

In reply, DTE Electric argued that ABATE's regulatory plan would have harmful consequences for customers and the company. According to DTE Electric, "accelerated ADIT amortization would negatively impact the Company's cash flows and financial integrity. There would be a $172 million incremental yearly cash flow loss to the Company, which would be directly reflected in the numerator of the key FFO/debt financial metric." DTE Electric's reply brief, pp. 70-71. In addition, the company claimed that long-term debt and capital costs would increase. DTE Electric explained that if ADIT is accelerated, deferred taxes would be replaced with debt and equity in the capital structure, and customers will experience higher capital costs after five years.

The ALJ first noted that ABATE's Table 2 contains an error that overstates the cost of service associated with the accelerated depreciation of the Tier 2 units. She stated that, because of the error:

> ABATE's proposed amortization appears to go significantly beyond offsetting the increases associated with the accelerated plant depreciation and new plant costs.
>
> Nonetheless, the ALJ finds the concept underlying ABATE's proposal has merit, and should be studied further in DTE Electric's next rate case.

PFD, p. 122. The ALJ recommended that the Commission direct DTE Electric, in its next rate case, to provide an analysis of the excess ADIT amortization required to offset the increased depreciation expense resulting from the early retirements of the Tier 2 units and the Belle River unit. In addition, she recommended that DTE Electric be required to present the revenue requirement associated with BWEC, "including an analysis of the impact on current and proposed cash flows and FFO-to-debt ratios, and an analysis of the appropriate allocation of the additional excess ADIT amortization amount." *Id*., pp. 122-123.

DTE Electric excepts, arguing that it is unnecessary to examine a more rapid amortization of unprotected excess ADIT balances. First, the company reasserts that the regulatory plan proposed by ABATE would negatively affect DTE Electric's cash flows. Second, DTE Electric contends that:

> ABATE's regulatory plan proposal was based on an assumption that the Company's new depreciation rates would be higher due to the retirement of its Tier 2 plants. In the approved settlement agreement in Case No. U-18150, the Company was directed to maintain the existing depreciation rates from the U-16117 Order for its Tier 2 plants. As a result there is no increased depreciation expense, thus making the proposed analysis unnecessary.

DTE Electric's exceptions, p. 42.

In exceptions, the Attorney General asserts that the ALJ erred in failing to recommend adoption of ABATE's regulatory plan. She argues that "[w]aiting until the conclusion of DTE's next rate case to implement this concept will unnecessarily harm all ratepayers by allowing for an unreasonable and significant cost increase on customers in *this* rate case." Attorney General's exceptions, p. 17. According to the Attorney General, further study of the regulatory plan is unnecessary because the requisite information for implementing the plan is already available in this case.

ABATE acknowledges that DTE Electric filed a settlement agreement in its depreciation rate case which lowered the proposed depreciation expense in this case. However, on page 6 of its exceptions, ABATE states that its "regulatory plan can still be implemented while calibrating the annual amount of excess ADIT credits to offset this incremental depreciation expense, and the BWEC construction carrying charges." ABATE asserts that adjusting DTE Electric's excess ADIT amortization periods will not negatively affect the company's financial standing and credit metrics and will significantly benefit ratepayers in this case.

DTE Electric replies to ABATE and the Attorney General, reiterating that ABATE's proposed regulatory plan could "harm both customers and the Company by negatively impacting DTE Electric's cash flows and potentially the Company's credit ratings, which would subsequently result in higher financing costs." DTE Electric's replies to exceptions, p. 28. Because of these negative impacts, the company states that there is no need to further study the regulatory plan in a future rate case, especially in light of the settlement agreement in Case No. U-18150.

In her replies to exceptions, the Attorney General continues to support ABATE's proposed regulatory plan, albeit as amended in ABATE's exceptions. She restates that the information necessary for implementing the plan is available in the record in this case and recommends that the Commission adopt ABATE's amended plan to accelerate the return of excess ADIT to customers.

In reply, ABATE continues to advocate for its proposed regulatory plan. According to ABATE, notwithstanding the settlement agreement in Case No. U-18150, DTE Electric's depreciation expense will be increased by $90 million to account for the accelerated recovery of its Tier 1 coal-fired generating units. ABATE also disputes DTE Electric's claim that the regulatory plan will negatively affect the company's cash flows. In ABATE's opinion, DTE Electric's "concerns are based on flawed analyses and a failure to recognize DTE's prospective increase in cost of service due to the Tier 1 coal-fired generating units, and the BWEC construction period carrying charges." ABATE's replies to exceptions, p. 10.

The Commission finds that DTE Electric's proposed amortization of the excess ADIT, with the Staff's adjustment to the deferred tax amount, should be approved. The Commission declines to adopt ABATE's proposed regulatory plan because the excess unprotected ADIT cannot be used to directly offset increased depreciation rates or carrying costs associated with construction work in progress (CWIP). However, in light of future developments in pending Calculation C cases, possible early plant retirements, and other rate adjustments, the Commission finds that, in DTE Electric's next general rate case, the parties should evaluate the benefits and costs of an accelerated amortization of the excess unprotected ADIT.

B. Debt Cost

DTE Electric and the Staff agreed to a short-term debt cost rate of 3.56% and a long-term debt cost rate of 4.36%. The ALJ recommended that the Commission adopt these cost rates. No party filed exceptions and, therefore, the Commission approves DTE Electric's debt cost rates.

C. Cost of Equity

1. Return on Equity

The criteria for establishing a fair ROR for public utilities is rooted in the language of the landmark United States Supreme Court cases *Bluefield Waterworks & Improvement Co v Public Service Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923) and *Federal Power Comm v Hope Natural Gas Co,* 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair ROR, consideration should be given to both investors and customers. The ROR should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise. Nevertheless, the determination of what is fair or reasonable, "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." *Township of Meridian v City of East Lansing*, 342 Mich 734, 749; 71 NW2d 234 (1955). With these principles in mind, the Commission turns to the factors that form the basis for determining the ROR for DTE Electric.

The ALJ provided a well-written summary of the parties' cost of equity analyses and arguments in the PFD. PFD, pp. 123-128. DTE Electric proposed an ROE of 10.50% based on a proxy group of 25 companies, to which it applied the Risk Positioning or Risk Premium (RP) analysis, the Discounted Cash Flow (DCF) approach, the Capital Asset Pricing Model (CAPM), and the empirical approximation to the CAPM (ECAPM). DTE Electric's initial brief, pp. 50-55. The Staff recommended an ROE of 9.80%, which was towards the high end of its calculated range of 9.00% to 10.00%, based on a proxy group of 11 companies to which it applied the DCF, CAPM, and RP approaches, in addition to reviewing other state commission ROE decisions. Staff's initial brief, pp. 51-55. The Attorney General recommended an ROE of 9.50% using a proxy group of 11 companies, to which she applied the DCF, CAPM, and RP analyses, while also considering the economic and interest rate environment for the company in recent years, the improving Michigan economy, and ROEs granted by other regulatory commissions around the country in 2017 and the first half of 2018. Attorney General's initial brief, pp. 92-110. ABATE proposed an ROE of 9.30%, the midpoint of its recommended range of 9.00% to 9.60%. ABATE's initial brief, pp. 26-38. In reaching this recommendation, it considered the company's strong credit rating and how a lower ROE would allow DTE Electric to offer more competitive retail electric rates to its customers than the rates these customers have had to pay in recent years. ABATE further considered industry authorized ROEs for electric utilities that have fallen in the range of 9.60%, or the high end of its recommended range. From this market evidence, ABATE concluded that the market cost of equity for the utilities is in the mid-9% area. Wal-Mart opposed DTE Electric's requested 10.50% ROE as excessive in light of the impact to its customers, the reduced risk inherent in Michigan's regulatory framework, the reduced risk created by the inclusion of CWIP in rate base and the proposed infrastructure recovery mechanism (IRM), and recent rate case ROEs approved by the Commission and others nationwide. Wal-Mart's initial brief, pp. 2-7. Like the other parties, RCG requested that the Commission reject DTE Electric's proposed ROE because it is inappropriately expensive for customers, and the company's financial status and credit ratings are not at risk. RCG's initial brief, pp. 8-10. Finally, because "DTE has a higher cost of electricity, lower reliability, and higher emissions rates than most other utilities across the country," MEC/NRDC/SC recommended that the Commission reject DTE Electric's requested ROE and, instead, approve an ROE that is "somewhat below national average." MEC/NRDC/SC's initial brief, p. 103.

The ALJ noted that the proposed ROE ranges and recommendations are almost identical to those in DTE Electric's previous rate case. She stated that:

> Ordinarily, [the ROE] section [of the PFD] would provide a detailed review of the various models, inputs analyses and recommendations of DTE Electric, the Staff, the Attorney General, and ABATE, along with the numerous, often-repeated critiques of the modeling approaches. However, given how close the results and recommendations are in this case compared to those in the company's previous rate case, coupled with the short time that has elapsed since DTE Electric's ROE was last determined, an exhaustive rehash of these issues is simply not warranted.

PFD, p. 125. The ALJ reviewed DTE Electric's concerns, which include: (1) uncertainty in the capital and global markets, (2) a less-than-favorable Michigan economy, (3) the company's financial risk and unique risk factors, (4) changes in the business structure of utilities, (5) increasing interest rates, (6) the TCJA, and (7) a need for a positive regulatory environment. She found that, with the exception of the effects of the TCJA, which was previously addressed in the PFD, "all of these factors were present 11 months ago and were recognized by the Commission" in the 2018 orders. *Id*., p. 126. Therefore, the ALJ determined that there has not been a sufficient change in the "underlying economic conditions" since the 2018 orders to justify a 50 basis-point increase in DTE Electric's ROE. *Id*., pp. 125-128, quoting the March 29, 2018 order in Case No. U-18322, p. 44.

Likewise, because there is insufficient evidence demonstrating a significant change in economic conditions, the ALJ found that the 20, 25, or 65 basis-point reductions requested by the Staff, the Attorney General, and ABATE, respectively, are not justified. As a result, the ALJ recommended that the Commission retain DTE Electric's current ROE of 10.00%.

In exceptions, DTE Electric reiterates the arguments set forth in its briefing, stating that the ROEs recommended by the Staff, the Attorney General, and ABATE "underestimate the effect that interest rates have had, and will continue to have, on the cost of capital for the Company," do not "adequately capture the risk in the electric utility industry," fail to consider the effects of the TCJA, and are understated due to analytical errors and the misperception that DTE Electric has average risk relative to the sample companies used. DTE Electric's exceptions, pp. 44-48.

The company claims that past concerns still exist, such as the current environment of low electric demand growth, its lack of a revenue decoupling mechanism, and lack of a fixed variable pricing policy, which places it at increased risk of under-recovering its cost of service (COS). DTE Electric asserts that it faces increased risk of underrecovery due to Michigan's economy, which is heavily dependent on the auto industry, and the peculiarities of its service territory in southeastern Michigan including Detroit, which has a weak economy and a declining and shifting population. The company also mentions its asymmetrical or downside risk resulting from the ownership and operation of a nuclear power plant.

Finally, DTE Electric alleges that its "cost of equity and capital structure are inextricably intertwined because the use of debt increases the company's financial risk, and therefore increases the Company's cost of equity." *Id.*, p. 49. Specifically, the company warns that a lower equity ratio and corresponding higher debt component in the capital structure creates higher risk for shareholders. Therefore, if the Commission rejects the company's proposed common equity ratio, DTE Electric argues that its ROE must be increased to compensate for the increased risk.

The Staff excepts, arguing that the ALJ's proposed 10.00% ROE "adds approximately $18 million in additional revenue requirement in this case." Staff's exceptions, p. 6. The Staff requests that the Commission adopt its 9.80% ROE recommendation, stating that it exceeds the average ROE of its proxy group at 9.73%, it is higher than the average in 37 rate cases across the nation, it is not a significant departure from DTE Electric's current ROE, it accounts for current low interest rates, and is reasonable considering the company's request for an IRM.

In exceptions, the Attorney General alleges that the ALJ failed to appropriately analyze the parties' proposed ROEs. She disagrees with the ALJ that the "only determination to be made is 'whether "underlying economic conditions" have changed sufficiently since April 18, 2018 to justify DTE Electric's recommended 10.5% ROE.'" Attorney General's exceptions, p. 19. Rather, she argues, a more appropriate ROE evaluation should include application of generally accepted models, an examination of the rate paid by Michigan customers compared to similarly situated customers in other states, and a study of the decline in ROEs around the country. The Attorney General recommended an ROE of no more than 9.50%.

ABATE excepts, asserting that the ALJ's recommended ROE is at least 40 basis points above industry average. In addition, ABATE claims that DTE Electric does not require an ROE higher than industry peers because the company faces a lower risk compared to the proxy group, economic conditions have improved in Michigan, and the TCJA has not negatively affected the company.

In exceptions, RCG reiterates that DTE Electric's credit ratings are not at risk and it is a financially strong company and, therefore, an ROE of 10.00% is unnecessary. RCG states that it supports the Staff's recommended ROE of 9.80%.

DTE Electric replies, reiterating the arguments set forth in briefing and exceptions, requesting that the Commission adopt its recommended 10.50% ROE.

On pages 11-12 of its replies to exceptions, the Staff states that:

> Since the Company provided no analysis or record evidence, there is no way to conclude that DTE Electric is riskier than Dr. Vilbert's proxy group. . . . In addition, the Company's credit rating by S&P [Standard and Poor's] and Moody's, is higher than Staff's proxy group's average credit rating. This implies that, all other things being equal, the credit rating agencies view DTE Electric as having equivalent to lower business risk than that of Staff's or Dr. Vilbert's proxy groups.

Additionally, the Staff asserts that the TCJA did not negatively impact DTE Electric's credit rating or its credit outlook. Therefore, the Staff reiterates that an ROE of 9.80% is sufficient and recommended.

In response to DTE Electric's claims that it has a greater than average risk, that there is uncertainty in the capital markets, it faces a challenging economic environment, and there are negative impacts from the TCJA, the Attorney General asserts that the company makes these arguments in each rate case and has failed to provide persuasive evidence to support the claims. Attorney General's replies to exceptions, pp. 19-20. She maintains that DTE Electric's ROE should be no higher than 9.50%.

The Commission notes that DTE Electric argues that economic conditions have changed since the company's prior rate case as a result of the TCJA and ongoing uncertainty in the financial markets affecting the cost of capital. Testifying regarding increased volatility in global capital markets and uncertainty from the Federal Reserve Bank, DTE Electric's witness stated:

> Although economic conditions have improved substantially since the start of the crisis in about mid-2008, uncertainty remains in the capital markets due, in part, to the disappointing rate of economic growth, not only in the U.S., but also worldwide. This volatility and uncertainty in the capital markets has increased since the Company's prior rate case application. Worries about the global economic and political instability have added to the concern, including the possibility of a trade war. In addition, the negative effects of the recent tax reform on regulated companies' cash flow further increase the risk of electric utilities.
>
> * * *
>
> While long-term government bond yields, which had dropped after the 2008-2009 credit crisis to unusually low levels, remain depressed relative to forecasts of future interest rates, recent economic activity and actions by the Federal Reserve (the "Fed") have caused an increase in current bond yields. As a result, bond yield spreads are declining from their elevated levels since the credit crisis, both for riskier assets as well as for less risky investments such as investment grade-rated utility debt. Although the capital market indices have returned to or exceeded their pre-crisis levels, the recovery remains fragile in part because of the weakness in the rest of the world.

6 Tr 1917-1918. Discussing DTE Electric's specific risks, he further states, "To the extent these forces make the Company more sensitive to volatility in the broader economy, they increase DTE Electric's systematic business risk and thus its cost of capital." *Id*., p. 1945.

With the exception of the TCJA, the Commission finds that DTE Electric expressed the same concerns, almost word-for-word, in Case No. U-18255 regarding uncertainty in financial markets, increased volatility in global capital markets, and a challenging economic environment. *See*, 6 Tr 1917-1924, 1927-1929, 1945-1946; *compare*, 8 Tr 1394-1400, 1409, 1412-1414; 1427-1429 in Case No. U-18255. Furthermore, the company admits that it was not identified by Moody's as a utility that should receive a negative outlook as a result of negative cash flow impacts from the

TCJA. Therefore, the Commission is not persuaded that economic conditions have changed sufficiently, if at all, to warrant an increase in DTE Electric's ROE.

The Commission finds that preserving an ROE of 10.00% most appropriately compensates DTE Electric for the regional economic and company-specific aspects of risk, while maintaining its ability to attract capital, and ensuring the continued vitality of the company. It also strikes a balance between the company's interest in investment and the interests of DTE Electric's ratepayers in safe, reliable, and affordable energy. The Commission, in reaching its determination, also takes into consideration the company's unique circumstances and characteristics, rising interest rates, and the standards set forth in *Bluefield* and *Hope*. The Commission is confident that a 10.00% ROE satisfies the criteria in *Bluefield* and *Hope* in that it is not so high as to place an unnecessary burden on ratepayers, but high enough to ensure investor confidence in the financial soundness of the business. Finally, the Commission is confident that this ROE is appropriate given the company's known capital expenditures.

By maintaining DTE Electric's ROE of 10.00%, the Commission believes there is an opportunity for the company to earn a fair return during these market conditions. This decision also reinforces the Commission's belief that customers do not benefit simply from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner. The fact that other utilities have been able to access capital using lower ROEs, as argued by many intervenors, is a relevant consideration. It is also important to consider how extreme market reactions to singular events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future applications to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE.

2. Other Cost of Capital Issues

MEC/NRDC/SC asserted that the Commission has the authority, pursuant to MCL 460.6u, to consider a utility's performance, such as customer service and service quality, when determining the utility's ROE and employee compensation structure. For DTE Electric specifically, MEC/NRDC/SC stated that the Commission should consider the company's performance on issues such as affordability, reliability, emissions and pollution, and impacts to financially-vulnerable customers. MEC/NRDC/SC recommended that the Commission commence a stakeholder process to evaluate various performance-based regulation (PBR) models, which could then be used in DTE Electric's next rate case.

The Staff did not advocate for PBR in this case because it previously recommended in Case No. 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." Staff's initial brief, pp. 157-158. However, the Staff asserted that the use of performance metrics and PBR would facilitate regulatory efficiency because the Staff will be able to focus on "key customer focused performance areas, rather than spending plans and specific costs incurred during the IRM." *Id*., p. 157.

In reply, DTE Electric argued that because PBR and the associated measures and metrics would have significant financial, operational, and regulatory effects for the company and its customers, it should be evaluated in a general rate case proceeding "where both the measures/metrics associated with PBR and the Company's planned investments can be reviewed in tandem." DTE Electric's reply brief, pp. 153-154. The company stated that it would be open to a stakeholder collaborative with a limited number of participants to examine the concepts of PBR, however it would not be useful or efficient to establish the "foundations and standards of PBR in such a forum." *Id*., p. 154.

Because no party provided sufficient detail about the implementation of PBR, the ALJ declined to extensively review the issue. However, she agreed with MEC/NRDC/SC and the Staff that the framework for PBR should be established in a stakeholder collaborative, with details regarding incentives and disincentives developed in a subsequent rate case. PFD, p. 129.

The Commission adopts the ALJ's recommendation. The Commission finds that, because of the time restriction and narrow scope, it would be less effective and disadvantageous to evaluate and establish the PBR framework in a rate case proceeding. As indicated in the Commission's April 20, 2018 Report on the Study of Performance Based Regulation, filed with the Michigan Legislature and the Governor, the Commission is open to PBR concepts and pilots. A pilot covering a discrete set of investments (e.g., components in the distribution plan) would provide an opportunity to test concepts, but could actually frustrate the regulatory process, at least in the near term, with overlapping rate cases and new proceedings to review IRM plans and reconciliations. Another path would be to develop a comprehensive performance-based approach, initially through a collaborative process with stakeholder input and dialogue and followed by application in a rate case as discussed earlier in this order. This course of action is being contemplated pursuant to the settlement agreement approved by the Commission in Consumers' last rate case (Case No. U-20134), with the utility leading workgroup discussions during 2019, prior to its next rate case. The Commission expects the Staff to participate in these discussions, which may inform the viability of such an approach and the relative feasibility, priority, and timing given the multitude of issues (interconnection standards, IRPs, rate design, etc.) facing the utilities, the Commission, and stakeholders.

D. Overall Rate of Return

The Commission adopts a 50/50 debt to equity capital structure, a long-term debt cost rate of 4.36%, a short-term debt cost rate of 3.56%, an ROE of 10.00%, and an overall weighted cost of capital of 5.48%, as shown on the table below:

Description	Amount ($000)	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	6,515,850	37.94%	4.36%	1.65%
Preferred Stock	0	0.00%	0.00%	0.00%
Common Shareholders' Equity	6,515,850	37.94%	10.00%	3.79%
Short-Term Debt	112,875	0.66%	3.56%	0.02%
Investment Tax Credit (ITC) - Debt	10,433	0.06%	4.36%	0.00%
Investment Tax Credit (ITC) - Equity	10,858	0.06%	10.00%	0.01%
Deferred Income Taxes (Net)	4,006,648	23.33%	0.000%	0.00%
Total	17,172,513	100.00%		5.48%

V. ADJUSTED NET OPERATING INCOME

Net operating income (NOI) is calculated by subtracting the company’s operating expenses including depreciation, taxes, and AFUDC, from the company’s operating revenue. Adjusted NOI includes the ratemaking adjustments to the recorded NOI test year for projections and disallowances. On pages 130-175 of her PFD, the ALJ provided a thorough analysis of the issues and arguments in adjusted NOI which will not be extensively repeated here. The Staff projected an adjusted total NOI of $829.9 million, and DTE Electric eventually projected a total NOI of $801.7 million.[7]

DTE Electric, in its replies to exceptions, notes it projected an adjusted total NOI of $801.7 million while the ALJ recommended an adjusted total NOI of $847.4 million on Appendix C of the PFD. DTE Electric's replies to exceptions, p. 32.

A. Operations and Maintenance Expense

In its application, DTE Electric projected a total O&M expense of $1,312.4 million for the test year, but subsequently reduced its projection to $1,309.8 million. DTE Electric's initial brief, p. 65. The Staff proposed an O&M expense of $1,279.8 million in its brief. Staff's initial brief, p. 64. The ALJ addressed several contested issues.

1. Inflation

DTE Electric proposed using a composite labor/non-labor inflation rate of 3.0% for 2018, 2.9% for 2019, and 1.0% for 2020. Exhibit A-13, Schedules C5.15, C5.2. DTE Electric's composite rates are using a 3.0% inflation rate for labor, and the consumer price index-urban (CPI) for non-labor costs. DTE Electric argued these are conservative estimates because of the obligations in the collective bargaining agreements for labor costs. DTE Electric's initial brief, pp. 65-66. DTE Electric argued that the increase in O&M expense from the historic period is projected to be $78.3 million, primarily due to labor cost inflation. 7 Tr 3303; Exhibit A-13, Schedule C5.

[7] The following issues were either undisputed or drew no exceptions, and the Commission adopts the recommendations of the ALJ on each of them: (1) sales forecast and revenue projection; (2) power supply costs; (3) St. Clair outage normalization adjustment; (4) fuel supply and MERC expense; (5) Fermi 2 expense; (6) community lighting expense; and (7) other operating income adjustments. PFD, pp. 130-131, 137-138, 148.

The Staff projected an inflation rate of 2.52%, 2.23% and 2.50% for 2018-2020, respectively. The rates proposed by the Staff result in a reduction of $12,338,000 to the company's O&M expense. The Staff argued that DTE Electric did not rebut the recommended inflation adjustments, and therefore, the Staff's inflation amounts should be adopted. Staff's initial brief, p. 65.

The Attorney General opposed DTE Electric's use of a combined labor/non-labor inflation rate and argued that the Commission has not adopted such a blended rate in any recent rate cases. The Attorney General further argued DTE Electric's actual O&M costs have been on a declining trend in the most recent six years, including 2017, making it difficult to understand why the company would project inflation-related cost increases for 2018, 2019, and the four months in 2020. 5 Tr 1595-1596; Exhibit AG-1. The Attorney General recommended that the Commission remove inflation from all O&M expenses except for healthcare, resulting in an adjustment of $75.4 million. *Id.*, p. 1598.

Kroger opposed the inclusion of a generic inflation factor to non-labor O&M expense. Kroger argued including inflation can make inflation a self-fulfilling prophesy and since these are already projected costs an additional "cost cushion" is unnecessary. 7 Tr 2739-2740. Kroger further argued DTE Electric did not project any efficiencies in its O&M expenses which might offset inflation. PFD, p. 134.

The ALJ found that the Staff's inflation rates should be applied to O&M expense. The ALJ agreed with the Attorney General that the use of a composite inflation rate has been rejected in the company's past two rate cases, and with the Staff that the company did not rebut the Staff's position, which recognizes that some inflation is likely to occur, but that productivity increases will offset higher labor inflation rates. Further, the ALJ encouraged the parties, in future cases, to more closely scrutinize the impacts on productivity gains to offset inflation on historical O&M costs. PFD, p. 135.

In exceptions, the Attorney General disagrees with the ALJ that productivity gains should be analyzed by the parties relative to inflation adjustments as the Attorney General has already provided this analysis through her testimony and briefs. The Attorney General argues that, in this and previous cases, she has shown that productivity gains have consistently offset inflation. The Attorney General urges the Commission to disregard the ALJ's recommendation to only examine the effects of inflation on historical O&M costs in future cases. Attorney General's exceptions, pp. 21-22.

In exceptions, DTE Electric contends that, while the Commission previously declined to adopt the combined inflation rate due to a lack of justification, the record in this case supports adoption of the company's proposed inflation rates. The company reiterates its argument that collective bargaining agreements require the company to increase pay rates by 3.0% annually, which drive the increase in inflation costs. DTE Electric's exceptions, pp. 50-52.

In its replies to exceptions, DTE Electric argues against the Attorney General's assertion that the company could offset inflation with productivity gains, due to the collective bargaining agreements. DTE Electric further argues that the Commission has rejected the Attorney General's argument to negate inflation in previous cases. DTE Electric's replies to exceptions, pp. 33-36.

In her replies to exceptions, the Attorney General argues against allowing projected inflation as a self-fulfilling prophecy, and recommends removing all O&M expense inflations, except from healthcare. The Attorney General argues that, at a minimum, the Commission should follow the Staff's inflation factors as recommended by the ALJ. Attorney General's replies to exceptions, pp. 21-23.

The Commission agrees with the ALJ that DTE Electric has not presented sufficient evidence in this case to induce the Commission to depart from its decisions in the 2018 orders and previous rate cases rejecting a blended inflation rate. The Commission agrees with the Staff that while DTE Electric will see some inflation, the company will also offset some of the inflation with productivity gains. Therefore, the Commission finds the Staff's proposed inflation rates to be the most reasonable and adopts the findings and recommendations of the ALJ.

2. Fossil Generation

With regard to River Rouge Unit 3 O&M expense, the Commission's decision is set forth in the rate base section, pp. 9-15, *supra*.

3. Distribution Operations Expense – Tree Trimming

DTE Electric proposed $330.5 million for its total distribution O&M expense for the test year, based on actual 2017 O&M expenses, normalized and adjusted. DTE Electric provided an overview of historic and projected tree-trimming expenses for the Enhanced Tree Trimming Program (ETTP), noting that the company is projecting O&M expense of $95.1 million for the test year, including inflation, maintenance and staff, and herbicides. 3 Tr 223; Exhibit A-13, Schedule C5.6, p. 3. DTE Electric stated that in 2017, it trimmed 3,601 miles on 305 separate circuits, compared to a plan of 3,618 miles. The company also spent $84.3 million for ETTP work, $9.1 million more than the $75.2 million approved in Case No. U-18014. DTE Electric reported that the number of customer interruptions was reduced by about 50%, and the number of minutes of interruption was reduced by 80% in the circuits that were trimmed as part of the ETTP compared to circuits that were trimmed conventionally. 3 Tr 200-201. DTE Electric further indicated that even in the major storm event in May 2017, the ETTP trimmed circuits performed significantly better than the company's other circuits. 3 Tr 204. DTE Electric explained that tree interference causes two thirds of customer outages and that the means to address this problem is a robust tree-trimming program, which DTE Electric has proposed as the surge program.

DTE Electric contended that it needs to trim about 6,500 miles per year to achieve the optimal five-year cycle. *Id*., pp. 207-208. DTE Electric claimed that reducing the tree-trimming cycle to five years will result in numerous customer benefits including fewer complaints and wire down events, fewer outages with lower reactive O&M costs, and lower tree-trimming costs in the future. *Id*., p. 216; Exhibit A-22 Schedule L1 (Revised). To arrive at its five-year tree-trimming objective, DTE Electric proposed a seven-year tree-trimming surge that will allow the company to address the three to four-year backlog of untrimmed circuits while at the same time maintaining the ETTP circuits at a five-year trimming interval. *Id*., pp. 211-212. Therefore, in addition to the $95.1 million base O&M expense amount, DTE Electric requested $43.3 million and $74.1 million for 2019 and 2020, respectively, of additional funding for its tree-trimming surge program. *Id*., p. 226; Exhibit A-22, Schedule L1 (Revised), line 11. DTE Electric proposed that the additional amounts for the surge program be deferred as a regulatory asset and amortized over 14 years, and eventually will be securitized. DTE Electric stated that the total cost of the tree-trimming program from 2019-2025 is $1.13 billion, with $722 million recovered through base utility rates and $410 million through the alternative mechanism of a regulatory asset and then securitization. *Id*., p. 234. DTE Electric argued that upon completion of the surge program in seven years, it should have a 40% reduction in tree-related outage events and a 40% reduction in tree-related SAIDI. *Id*., pp. 217-218. DTE Electric explained that approximately 1,300 tree trimmers will be required to implement the program by 2022, 450 more than currently work for DTE Electric. *Id*., pp. 237-238. DTE Electric proposed providing annual reports to the Commission on ETTP circuit performance comparing average outages for three years prior to the enhanced trimming along with outages in the year after the trimming is performed. In addition, DTE Electric offered to submit a Tree Trimming Effectiveness Report in 2022. DTE Electric requested regulatory asset treatment for excess ETTP costs, to defer the costs of the surge program, and to amortize each vintage year balance over a 14-year period. The deferred costs of $43.3 million for the first year of the program divided by 14 years equals approximately $3.1 million per year in amortization costs. 7 Tr 3336; Exhibit A-22, Schedule L3. DTE Electric proposed that prior to securitization, the regulatory asset for the tree trimming surge will be financed consistent with the company's capital structure and once the regulatory asset balance reaches $100 million, DTE Electric intends to securitize the asset. This securitization of the regulatory asset is expected to occur every other year starting in 2020. 5 Tr 1053-1054.

The Staff supported the company's objective to reach a five-year tree trimming cycle for distribution circuits, as well as a three-year cycle for sub-transmission, noting that DTE Electric will require additional funding over time to address the backlog of trees that are not trimmed to ETTP standards. However, given the additional cost associated with amortization, the Staff opined that DTE Electric's proposed deferral is not in the best interest of ratepayers. 8 Tr 4127-4128. The Staff argued that although the additional cost of the tree trimming surge is $410 million, because of the company's proposed regulatory asset treatment, the costs could be as high as $600 million due to the return on the deferral of costs over $95 million. Securitization could reduce this cost some, but ratepayers would still be paying an O&M expense over 14 years rather than as the cost is incurred. Staff's initial brief, p. 72. As an alternative to DTE Electric's proposal, the Staff recommended that the Commission disallow the $7,053,000 revenue requirement associated with deferred ETTP costs and instead increase the O&M expense amount for tree trimming from $95,092,000 to $108,099,000. The Staff explained that in subsequent rate cases, the company may request additional O&M for the ETTP, until the backlog is cleared. At that time, the company could reduce its O&M amount to that shown in Exhibit A-22, Schedule L1. The Staff argued that keeping tree trim O&M expense embedded in rates and gradually increasing the O&M tree trimming expense makes the surge more affordable in the short term, and protects customers since DTE Electric admitted that it may not be able to secure enough tree trimmers over the next couple of years to execute its surge plan as proposed. Staff's reply brief, pp. 6-7.

The Attorney General supported the tree trimming program proposed by DTE Electric, but she also recommended that the company be held accountable for the results of the program by meeting certain interim goals. The Attorney General proposed target levels for number of outages, reporting of accomplishments and spending, and achievement of at least 80% of the target reductions in outages or forfeit recovery of 1% of the deferred expense for the years below the 80% target; and if the company continues to show failure to meet the target, the Commission should reset the spending levels in new years and the company would forfeit the remaining balance of the regulatory asset. 5 Tr 1604-1605.

RCG recommended that the Commission reject the deferral and amortization proposed by the company and adopt a tracker with actual tree-trimming costs reconciled periodically. PFD, p. 146. MEC/NRDC/SC recommended that "the Commission minimize other distribution system expenditures and require the [c]ompany to accelerate tree-trimming programs using enhanced tree[-]trimming practices to the most rapid pace that can be efficiently and properly executed." 6 Tr 2180. Further, MEC/NRDC/SC argued that tree trimming costs have increased in the past because DTE Electric failed to keep up with an appropriate tree trimming cycle and it is unfair to customers to pay more now to put the tree-trimming back on the appropriate schedule. 6 Tr 2182.

The ALJ agreed with the Staff's proposal to remove the amortization cost from the company's rate request and increase tree trimming O&M expense from $95.1 million to $108.1 million. In support of her decision, the ALJ noted that as the Staff, the Attorney General, RCG, and MEC/NRDC/SC pointed out, the proposed deferral and amortization of tree trimming costs could result in $200 million more in revenue requirement to cover the cost of the program. The ALJ agreed that the securitization of these excess costs would reduce the amount that would need to be recovered in the future, however, DTE Electric admitted the terms and conditions of the proposed securitization are not known at this time. The ALJ rejected DTE Electric's compromise, requesting an increase from the $95.1 million to $137 million if the Commission rejected the surge program, because she agreed with the Staff that a 64% increase in the tree-trimming budget at a time when there is significant uncertainty about the availability of tree-trimming labor would not be prudent. The ALJ agreed that a two-way tracker would protect the company in the event of overspending, and it would also protect customers if the company is unable to secure sufficient resources for the program, however, she did not make a recommendation on its implementation. The ALJ agreed that the Commission should consider reporting metrics, but she rejected the Attorney General's reporting requirements and possible penalties as unreasonable at this time. Lastly, based on a lack of sufficient evidence, the ALJ rejected MEC/NRDC/SC's recommendation to reduce cost recovery based on alleged underspending in prior periods. PFD, pp. 147-148.

In exceptions, DTE Electric maintains that the surge program should be approved, and if not, it urges the Commission to provide the $137.5 million of funding for the tree trim program; and the company indicates that it is receptive to a two-way tracker to protect ratepayers and allow the company an opportunity to accelerate the tree trimming plan. DTE Electric's exceptions, pp. 52-

58. DTE Electric also stated that the company has secured additional tree trim contract employees. DTE Electric's exceptions, p. 56.

In reply to DTE Electric's exceptions, the Staff argues the $410 million proposed to be deferred as a regulatory asset will be amortized over 20 years under DTE Electric's plan, not 14 years as stated by DTE Electric. Staff's replies to exceptions, pp. 4-5. Also, the Staff notes the additional tree trim contract employees mentioned by DTE Electric are not part of the record and should not be part of the Commission's decision. Staff's replies to exceptions, p. 5.

In her reply to DTE Electric's exceptions, the Attorney General reiterates her agreement that some increase to the ETTP program is reasonable, but she argues the level requested by DTE Electric is excessive and not in the best interests of the customers. The Attorney General argues that providing DTE Electric the requested level of funding without performance and accountability parameters is a considerable risk to ratepayers. The Attorney General recommends that the Commission reject DTE Electric's request and accept the ALJ's recommendation. Attorney General's replies to exceptions, pp. 23-25.

The Commission reiterates its desire for a safe and reliable electric system as stated on pp. 43-44 of the April 2018 order regarding the ETTP program. The record shows that DTE Electric has continued to bring tree trimming spending into line with the approved amounts, and the Commission agrees that falling behind in this area will cost more in the future and perpetuate reliability challenges. The record also shows direct, quantifiable benefits in terms of reliability improvements resulting from the ETTP program. 3 Tr 200-206. The Commission is also cognizant of the costs and workforce restraints associated with an aggressive tree trimming program. The Commission appreciates the progress DTE Electric has made to stay on target with its tree trimming commitment over the past several years, but there is a risk of falling short with the unprecedented O&M funding level proposed by the Staff as an alternative to the company's surge proposal, which uses regulatory asset/securitization treatment for expenditures above $100 million. The Commission finds it appropriate to move forward with the surge proposal as the best way to balance these considerations, but to only authorize the first three years. Thus, the Commission approves the originally requested $95.1 million of O&M for tree trimming in the projected test period, and the first three years of spending for the surge program, being $43.3 million for 2019, $74.1 million for 2020, and $70.5 million for 2021, as a regulatory asset, with application of the short-term debt cost rate adopted in this order of 3.56% rather than the pretax permanent overall cost of capital proposed by DTE Electric. This will reduce overall costs and is expected to be temporary given the company's plans to file for securitization of the tree trimming regulatory asset.[8] 5 Tr 1053. Thus, the Commission finds the short-term debt rate to be more appropriate than the overall cost of capital. The company may accrue carrying costs in the regulatory asset at the short-term debt rate, and may seek recovery in a future proceeding such as a securitization or rate case using a traditional ratemaking approach.

The Commission directs DTE Electric to submit an annual report on ETTP and surge miles in this docket, using DTE Electric's Table 12 at 3 Tr 231 in order to gain information broken out by geographical region. The Commission is deeply concerned that despite hearing a commitment from DTE Electric to improve and increase electric system maintenance programs, the utility's best efforts have not met Commission expectations for safety and reliability. Thus, the annual report shall also break out all activity, costs, and miles trimmed under any and all tree trimming

[8] The Commission notes that DTE Electric has indicated its intent to evaluate securitization of the remaining net book value of the Tier 2 plants pursuant to the settlement agreement approved in the company's most recent depreciation case. December 6, 2018 order in Case No. U-18150, Exhibit A, p. 3. This may also contribute to the temporary nature of the regulatory asset treatment of the surge costs.

programs (including hardening) in the city of Detroit, to provide information on the progress made in the city of Detroit with each program. The reporting shall include measurable data for the efforts, including miles completed by service center, performance of ETTP circuits compared to non-ETTP circuits, the costs of the efforts, number of employees directly involved in the efforts, tree-related outage reductions, SAIDI reductions, and whether the funding for the efforts is a capital expense or O&M cost. Further, the report shall track ETTP circuit performance, comparing average outages for the three years prior to the enhanced trimming with outages in the years after the trimming has been performed. The first report is due in this docket March 1, 2020, and an annual report is due on March 1 of each year thereafter. After the third year of the surge, DTE Electric shall also submit the Tree Trimming Effectiveness Report discussed in the company's testimony, in this docket. The Commission will revisit the regulatory asset treatment and the surge program in three years.

4. Customer Service and Marketing

a. Meter Reading

DTE Electric projected $3.4 million in meter reading expense. DTE Electric argued that the customer accounts expense category includes customer records and collection, customer records and collection-merchant fees, and meter reading expense. DTE Electric stated that the meter reading expense covers the cost of external vendors to manually read meters that are not AMI meters or that are part of the opt-out program, and other activities include billing operations pertaining to major accounts, metering operations, consecutive estimate team, and special reading expenses. 7 Tr 3113; Exhibit A-13, Schedule C5.7. DTE Electric asserted that the Staff's calculation is incorrect because meter reading expense comprises more than just the cost of external vendors to manually read meters, and the Staff's calculation does not include these additional costs. 7 Tr 3140.

In its initial brief, the Staff contended that the company's projection for meter reading expense does not reflect the reduced number of meter readers. The Staff contended it is imprudent to base test year meter reading costs on the 2017 historical year and argues that $2.147 million in meter reading expenses should be disallowed because DTE Electric has reduced the projected number of meter reading employees from 58 in the 2017 historical period, to 24 in the test period. Staff Exhibit S-12.3, p. 13; 8 Tr 4153. The Staff further pointed out that DTE Electric has given no information about the costs associated with the other categories of expenses that have fallen into the category of meter reading expenses. Staff's initial brief, p. 71.

The ALJ agreed that DTE Electric failed to reflect the substantial reduction in the number of manual meter readers the company employs in its O&M projection. She also agreed that DTE Electric failed to provide a breakdown of costs in the meter reading category to those that involve meter reading personnel and those that involve other meter reading cost categories. The ALJ agreed that the Staff's assumption that meter reading costs are largely comprised of contract personnel was a reasonable one. The ALJ recommended that the Staff's adjustment to meter reading O&M be adopted. PFD, p. 150.

In exceptions, DTE Electric maintains its argument that the meter reading costs cover additional activities as stated in its original testimony and the Commission should reject the ALJ's recommendation. DTE Electric's exceptions, pp. 58-59.

The Commission agrees with the ALJ that DTE Electric has not presented sufficient evidence on the additional activities allegedly covered in the meter reading expense. The Commission finds the Staff's reasoning regarding meter reading costs to be the most reasonable and therefore adopts the findings and recommendations of the ALJ.

b. Merchant Fees

DTE Electric proposed a $2.6 million increase for merchant fees to cover the increased cost of credit card processing, that being an additional $0.9 million increase for residential and a $1.8 million increase for small non-residential customer accounts on rates D3 including choice, D4, and D5.[9] DTE Electric proposed a change to who can pay by credit card, noting that, "Larger Commercial and Industrial customers on rate schedules D6.2, D8, D11, and Secondary choice customers will not be able to pay by credit card." 7 Tr 3121-3122. DTE Electric is citing the need for the additional funds and proposed change as "a year-over-year increase of 90% and a five-year compound annual growth rate of 60% in merchant fees for corporate credit cards." *Id*., p. 3121. DTE Electric argued that the merchant fees are approximately 2% of sales for non-residential customers and charging a 3% fee, as suggested by the Attorney General, would create dissatisfaction amongst the business customers and a possible increase in uncollectible expense. *Id*., p. 3143.

The Attorney General agreed with DTE Electric about prohibiting large commercial and industrial customers and secondary choice customers from paying by credit card, and to the increase in the credit card program for residential customers. 5 Tr 1607. However, the Attorney General recommended that the expense level for the non-residential customers' credit card program be set at $1.6 million, instead of the requested $5.0 million. The Attorney General argued that DTE Electric pays, on average, 6.7% in credit card fees and that DTE Electric should be granted permission to charge a 3% fee to businesses paying by credit card to minimize DTE

[9] The amounts do not precisely total due to rounding.

Electric's cost. *Id*., pp. 1607-1608. The Attorney General further argued that, "[s]plitting the credit card fees between the Company and this group of customers is a reasonable change to the program to avoid ever-increasing card fees for the rest of the customer base to absorb." *Id*., p. 1608.

The ALJ agreed with DTE Electric that merchant fees are a reasonable O&M expense. The ALJ agreed that the benefits of convenience and reduced uncollectibles outweigh the minor cost for the increasingly popular option for residential and small commercial customers to make a payment by credit card. PFD, p. 152.

In exceptions, the Attorney General argues the ALJ erred in recommending the recovery of $1.8 million increase in merchant fees for non-residential customers. The Attorney General argues the difference between a residential credit card program and a commercial program is that for residential customers the program increases customer convenience and reduces the risk of uncollectable costs, and these benefits do not necessarily apply to non-residential customers. The Attorney General argues the company pays on average 6.7% in fees on credit card payments, and as commercial customer bills are larger than most residential customers, this is an ever increasing and significant fee that is absorbed by all customers, including residential. The Attorney General again recommends that the Commission support a system allowing DTE Electric to charge a 3% fee to non-residential customers paying by credit card to minimize the costs, and, in conjunction with the fee, set the expense level for the non-residential program at $1.6 million, which is half the 2017 historic level of $3.2 million. Attorney General's exceptions, pp. 22-23.

In its replies to exceptions, DTE Electric argues against the Attorney General's proposal because the company asserts it does not pay 6.7% merchant fees as purported by the Attorney General in her exceptions. DTE Electric contends it incurs merchant fees of approximately 2.0%

for non-residential customers and 0.7% for residential customers. DTE Electric notes that it proposes limiting payment by credit card to only residential and smaller commercial and industrial customers. DTE Electric urges the Commission to approve the known and measurable adjustment for credit card processing fees. DTE Electric's replies to exceptions, pp. 35-36.

The Commission agrees with DTE Electric's proposed change to eliminate the option to pay by credit card for larger commercial and industrial customers, while preserving the option for residential and smaller commercial customers. The Commission agrees with the ALJ that merchant fees for residential and smaller commercial customers are a reasonable O&M expense. The Commission recognizes the increasing popularity of paying by credit card and the added convenience for the customer. Therefore, the Commission adopts the $2.6 million increase for merchant fees and the change in DTE Electric's current payment options to eliminate the credit card payment option for larger commercial and industrial customers on rate schedules D6.2, D8, D11, and secondary choice customers. The Commission directs DTE Electric in its next rate case filing to provide information on the reduction in uncollectibles attributable to credit card payments.

c. Customer 360

The Commission notes that Soulardarity argued in exceptions that DTE Electric's Customer 360 (C360) post-implementation O&M costs should not be approved. PFD, pp. 223, 300. Soulardarity argues that it is not just to approve these costs without requiring that DTE Electric provide adequate customer service, and asks the Commission to "consider those who lack digital access or literacy and those who have complicated, and sometimes urgent, issues that digital interfaces are not equipped to resolve." Soulardarity's exceptions, p. 7.

In reply, DTE Electric points out that the ALJ did not approve C360 costs in the cited portion of the PFD but rather approved regulatory asset treatment for certain C360 costs – an accounting request. PFD, p. 223. DTE Electric argues that it is attempting to remove barriers to access by expanding the modes for interface with the Customer Service department through digital applications. 7 Tr 3144. DTE Electric also points to the existence of the low-income payment plan, the Residential Income Assistance (RIA) program, and the Residential Service Special Low-Income Pilot.

The Commission agrees with the ALJ and adopts her findings and recommendations. The specified C360 costs are approved for regulatory asset treatment. DTE Electric is attempting to make its customer service platforms more inclusive and easier to use, and the Commission is not persuaded to de-fund the C360 effort. Soulardarity makes no attempt to describe what customer service platform would be used in its place, or why the costs of providing electronic access to customer service are not reasonable and prudent. DTE Electric continues to offer access to customer services by phone and mail as well. Soulardarity's exception is rejected.

5. Uncollectible Expense

a. Calculation of Uncollectible Expense

DTE Electric projected uncollectible expense to be $51.6 million for the test year, based on the use of a three-year average of actual uncollectibles from 2015 to 2017. DTE Electric argued that, despite the Staff's claim that the company's assumptions could result in a significant forecasting error, the reduction proposed by the Staff would only be $234,000. Furthermore, DTE Electric indicated that the historical period uncollectible expense has been approved by the Commission in past rates cases for both DTE Electric in Case Nos. U-18255 and U-18014, and DTE Gas in Case Nos. U-18999 and U-17999. DTE Electric's reply brief, pp. 108-109.

The Staff proposed that a cash basis method, using the 2015 to 2017 three-year average of the ratio of net charge offs to revenue, be utilized to project uncollectibles expense for the test period. By applying the resulting percentages to the present revenues for the projected test period the Staff arrived at an estimate of $51.4 million uncollectible expense for the test year. Exhibit S-3, Schedule C5.1. The Staff contended that the cash basis method is a better approach than DTE Electric's balance sheet method because it mitigates the potential for forecasting error and has been adopted by the Commission in Case Nos. U-14347, U-16191, U-16794, U-17735, and U-17990. Staff's initial brief, pp. 68-69.

The ALJ reasoned that the cash basis method has been approved by the Commission in a number of previous rate cases involving other utilities, and found that it is important to have consistency in the method utilized to determine uncollectible expense across the industry rather than utilizing different methods for each utility company. In addition, the ALJ found the Staff's method appeared more accurate and less prone to potentially significant forecasting error. Accordingly, the ALJ recommended the uncollectible O&M expense should be reduced by $234,000 consistent with the Staff's recommendation. PFD, pp. 154-155.

In exceptions, DTE Electric argues that its three-year average is more reliable than the cash basis method used by the Staff to determine the proposed uncollectible expense. DTE Electric urges the Commission to reject the ALJ's recommendation and adopt DTE Electric's three-year average methodology. DTE Electric's exceptions, pp. 59-60.

The Commission agrees with the ALJ that the cash basis methodology has been approved in previous cases and that consistency of method is important. The Commission finds the Staff's cash basis method to be the most accurate and least prone to potential forecasting error. Therefore, the Commission adopts the findings and recommendations of the ALJ.

b. Returned Check Charge

DTE Electric proposed an increase to its returned check charge from $15.00 to the statutory maximum of $28.66. DTE Electric explained that by increasing the returned check charge the company expects to deter customers from repeatedly making not-sufficient-funds (NSF) check payments. 7 Tr 3128-3129.

The Staff disagreed with DTE Electric's proposal to increase the returned check charge, arguing that customers who write an NSF check are often people who do not have a lot of resources and cannot easily absorb the increased charge. The Staff contended that the current $15.00 charge is enough to deter customers from making payments that are returned for insufficient funds so long as it is enforced. 8 Tr 4287-4288.

Soulardarity supported the Staff's position, arguing that nearly doubling the current NSF charge is unreasonable and that "it is objectionable for burdening those with less financial means." Soulardarity's reply brief, p. 2.

The ALJ agreed with the Staff and Soulardarity that DTE Electric's proposal simply increases the financial burden for those who can least afford to pay. Therefore, the ALJ recommended DTE Electric's proposal be rejected. PFD, p. 156.

In exceptions, DTE Electric maintains that the increased NSF charge would deter customers from repeatedly writing checks that are returned NSF and would therefore result in the most-affected customers paying less in total. DTE Electric urges the Commission to reject the ALJ's recommendation. DTE Electric's exceptions, pp. 60-61.

In reply, the Staff maintains its position that the increase affects those who can least afford the expense. The Staff further argues that no cost justification was provided by DTE Electric for this increase. Staff's replies to exceptions, p. 40.

The Commission agrees with the Staff and Soulardarity that an increase in the returned check fee increases the burden for customers who are already facing financial difficulties. Additionally, DTE Electric provided no evidence to support the need for the increased charge. The Commission finds the Staff's recommendation reasonable and in the best interests of the customer. Therefore, the Commission adopts the findings and recommendations of the ALJ.

6. Corporate Staff Group Expense

DTE Electric used an historical five-year average and the same cost allocation methodology as was approved by the Commission in past rate cases[10] to determine the test year projected amount for injuries and damages. 7 Tr 3311-3313; Exhibit A-13, Schedule C5-9, line 20, columns (f) and (l); PFD, p. 156. In its initial brief, the company removed inflation from its projection, thereby reducing its original projection by $0.09 million for an amended total projected amount of $183.90 million. DTE Electric's initial brief, p. 80. The Staff agreed with the use of a five-year average because injuries and damages tend to be "volatile and difficult to project." 8 Tr 4028. The Staff agreed that the company should remove inflation from its projection of this expense.

The Attorney General recommended that the company use a three-year average to determine the projected test year amount because to do so would remove 2013's relatively high expense from the average and result in a "normalized" test year projection. The Attorney General stated that, if adopted, the recommended three-year average would reduce the company's test year projection by $1.90 million. 5 Tr 1611-1612; Exhibit AG-7. DTE Electric replied that it would be inappropriate to adjust the number of test years to achieve a more desirable projection.

[10] On page 80 of its initial brief, DTE Electric cited the company's last seven general rate cases in support of the five-year time-frame: Case Nos. U-13808, U-15244, U-15768, U-16472, U-17767, U-18014, and U-18255.

Consistent with past Commission orders, the ALJ recommended that the Commission approve DTE Electric's projection methodology, stating the purpose of using the longer time-frame is to normalize annual fluctuations. The ALJ also recommended the removal of projected inflation. PFD, p. 157.

In her exceptions, the Attorney General argues that DTE Electric's expenses were $5 million higher in 2013 than in any of the other four historical years and past practice should not preclude the Commission from changing to a three-year average when such an anomaly exists. Attorney General's exceptions, pp. 24-25. In its replies to exceptions, DTE Electric again voices its disagreement with the Attorney General's position. DTE Electric's replies to exceptions, p. 36.

The Commission is not persuaded that $5 million in increased expense in one of the five test years (2013) is sufficient reason to shorten the five-year time-frame to three years such that 2013 is excluded. The Commission agrees with the ALJ's reasoning that the purpose of a longer time frame is to normalize expenditures. Accordingly, the Commission finds DTE Electric's projection is reasonable and prudent and adopts DTE Electric's amended projected amount of $183.90 million.

7. Pension and Other Post-Employment Benefits Expense

DTE Electric testified that pension costs, comprised of service costs, interest cost, expected return on assets, and amortization, are expected to decrease from $127.00 million to $68.10 million in the 2017 historical year. The company stated the expected reduction is due to its projected increase in the return on assets. 6 Tr 1812-1816; Exhibit A-13, Schedule C5.11.1; PFD, pp. 157-158.

DTE Electric's other post-employment benefit (OPEB) costs, consisting of retiree medical, dental, prescription drug, and life insurance benefits, and including service costs, interest cost, expected return on assets, and amortization, were also projected to decrease from negative $16.30 million in 2017 to negative $21.30 million in the projected year. Again, the expected reduction was attributed to DTE Electric's expected increase in the projected return on assets. 6 Tr 1816-1819; Exhibit A-13, C5.11.2; PFD, p. 158.

The ALJ stated that no party disagreed with DTE Electric's projections for pension and OPEB costs and recommended that the Commission approve them. PFD, p. 158.

In its exceptions, DTE Electric pointed out that, while it is true that no party disagreed with the company's pension and OPEB projections, the PFD was silent on other components of employee benefits expense. DTE Electric also pointed out that the company reduced its active healthcare expense for the amortization of a one-time credit of $1.7 million[11] as proposed by the Staff. DTE Electric's exceptions, p. 61; DTE Electric's initial brief, p. 83; 8 Tr 4029-4030; Exhibit A-13, Schedule C5.10, line 32.

The Commission agrees with the ALJ's recommendation and adopts DTE Electric's projections for pension and OPEB costs. *See*, PFD, Appendix C. The Commission notes that DTE Electric has reduced its projection for active health care cost by $1.73 million for the test year and, as the Staff suggested, the entire credit of $5.20 million is to be credited back to ratepayers over three years. *See*, Staff's initial brief, pp. 69-70; 8 Tr 4029-4030.

8. Employee Compensation Expense

DTE Electric projected an overall employee compensation expense of $46.40 million including recovery for the Long-Term Incentive Plan (LTIP), the Annual Incentive Plan (AIP),

[11] The actual first-year credit amount proposed by the Staff was $1.733 million for the projected test year ending April 30, 2020. The full amount proposed was $5.20 million to be credited back to ratepayers over a three-year period beginning May 1, 2019. 6 Tr 4028-4030.

and the Rewarding Employees Plan (REP). 6 Tr 1832-1862; DTE Electric's initial brief, pp. 86-91.

Based on consistent precedent, the Staff recommended exclusion of $27.1 million in LTIP, AIP, and REP costs associated with financial performance measures (this incorporates the entire LTIP cost). Also consistent with Commission orders, the Staff recommended inclusion of non-financial performance metrics costs of $19.3 million. 8 Tr 4048-4050.

The Attorney General proposed exclusion of all financial measure costs and 50% of non-financial performance metric costs. The Attorney General stated that all three of the company's incentive plans are "skewed" to measures that benefit shareholders, not customers. In addition, she argued that customer benefits are based on the faulty premise of historical cost savings and expectations that future performance targets will be achieved when, in fact, for both AIP and REP plans for all employment groups, only 50% of operating performance measures were achieved at 100% or better in 2015 and 2016. 5 Tr 1612-1620; Exhibit AG-11; Attorney General's initial brief, pp. 36-43.

MEC/NRDC/SC and MEIBC/IEI asserted that financial performance incentives may provide incentives to overstate expected costs to the Commission or to underspend on needed infrastructure. 6 Tr 2163. Additionally, they proposed that the Commission consider a process wherein stakeholders determine the performance metrics for performance compensation. 6 Tr 2163-2164; PFD, pp. 166-167. The ALJ noted that Kroger asked the Commission to take remedial action to address service quality issues. PFD, p. 167.

The ALJ recommended adoption of the Staff's proposal which, she noted, comports with the Commission's decision in the April 2018 order, p. 49, issued only one year ago, and which found that the utility had failed to show demonstrated ratepayer benefits arising from the financial metrics. The ALJ found that DTE Electric had again failed to make such a demonstration. PFD, pp. 171-172. Despite the company's arguments, the ALJ found that the utility had presented no new information or analysis in this case that would justify a result different from the 2018 orders.

The Attorney General filed exceptions, repeating her arguments. In reply, DTE Electric argues that the Attorney General is incorrect and employs faulty reasoning. DTE Electric contends that financial incentives benefit customers because such measures enhance the company's ability to realize increased productivity and cost savings, thereby postponing rate increases and, ultimately, providing higher quality customer service. DTE Electric's exceptions, p. 64.

In her replies to exceptions, the Attorney General continues to assert that DTE Electric will not achieve 100% of the incentive measures at 100% of the target level. She again argues that DTE Electric's own testimony and exhibits prove that the company achieves only 50% of the measures at 100%, a trend that continues year after year. Therefore, the Attorney General states, 50% of the company's short-term incentive compensation should be disallowed.

The Commission is not persuaded by either DTE Electric's or the Attorney General's arguments and adopts the findings and recommendations of the ALJ with regard to the disallowance of employee incentive compensation tied to financial measures and allowance of compensation tied to achievement of non-financial performance objectives. This is consistent with 11 prior Commission decisions and is reasonable and prudent given that incentive compensation tied to financial performance measures has not been shown to benefit ratepayers. PFD, pp. 171-172; *see* Staff's initial brief, pp. 67-68 (listing the 11 cases). The Commission agrees with the Staff and the ALJ that the company failed to present any new information persuading the Commission to deviate from its prior orders disallowing this O&M category. Notwithstanding the continuation of this approach, the Commission directs DTE Electric to provide additional detail on compensation, performance targets, and achievement in its next rate case to allow the Commission to evaluate whether adjustments should be made for the non-financial incentive structure authorized for recovery in rates.

9. Other Operations and Maintenance Expense Adjustments

a. Weekend Flex/Fixed Bill Pilot Program Expense

DTE Electric proposed two pilot programs that would provide for a limited number of customers to be differently billed for their energy use: the Weekend Flex pilot and the Fixed Bill pilot. These proposed pilot programs are fully discussed, below. *See*, Section X, Rate Design and Tariff Issues, subsection C. Fixed Bill and Weekend Flex Pilot Proposals. This section provides additional comments related to the disallowance of expenses in NOI to cover the implementation costs of the programs. The ALJ recommended disallowance of the two pilot programs.

In its exceptions, DTE Electric asserts that the purpose of the two pilots is to "address customer affordability and satisfaction," and voices its disagreement with the shortcomings asserted by other witnesses. DTE Electric's exceptions, pp. 103-106. In its replies to exceptions, the Staff argues that DTE Electric failed to show ALJ error and disagrees with the company's assertions regarding appropriate price signals provided by the proposed pilots. Staff's replies to exceptions, pp. 32-34

The Commission agrees with the ALJ and adopts her recommendation that proposed funding for the Weekend Flex and Fixed Bill pilot programs be disallowed and notes that denial of the pilots is discussed in detail below in the Rate Design section of this order, *infra*.

b. Edison Electric Institute Dues

DTE Electric requested approximately $1.269 million for dues paid to Edison Electric Institute (EEI). However, MEC/NRDC/SC asserted that the entire amount should be disallowed because it is possible that a portion of the dues are used to fund advocacy for the company that customers may disagree with and that is contrary to customer interests. MEC/NRDC/SC testified that it is unreasonable for DTE Electric to take EEI at its word regarding dues allocation in the absence of a third-party audit. 6 Tr 2520-2528; Exhibit MEC-31; PFD, pp. 173-174.

The ALJ recommended that, absent any evidence from DTE Electric rebutting MEC/NRDC/SC's testimony, the EEI dues should be disallowed. PFD, p. 174.

In its exceptions, DTE Electric states that the company "has consistently relied on invoices from EEI for properly recording recoverable and nonrecoverable dues on its books and has no reason to believe the amounts provided to [DTE Electric] by EEI are inaccurate." DTE Electric's exceptions, p. 69. The company points out that MEC/NRDC/SC did not provide any evidence that EEI's invoices improperly included nonrecoverable amounts and asserts that EEI provides valuable services to customers including public safety and workforce education and training.

The Commission is persuaded that DTE Electric's projected recovery of $1.269 million in EEI dues is reasonable and prudent and is consistent with past practice. The Commission notes that EEI provides many desirable services to utilities and their customers. In the absence of any evidence to the contrary, the Commission accepts DTE Electric's reliance on EEI's invoices at this time. Accordingly, the projected amount of approximately $1.269 million for dues paid to EEI is approved.

c. Allowance for Funds Used During Construction

DTE Electric projected a total AFUDC offset to construction work in progress (CWIP) by including an adjustment to its operating income of $32.973 million. This projection was supported by the company in Exhibit A-13, Schedule C11, and shown as an adjustment to its operating income in Exhibit A-13, Schedule C1. The Staff recommended that the projection be increased by $1,923,000 for a total AFUDC offset projection of $34.896 million. The Staff explained that the adjustment was needed because the company's adjustment did not offset the additional impact of AFUDC being included in CWIP. 8 Tr 4058-4059; Exhibit S-3, Schedule C1. DTE Electric rebutted that the company does not include an additional AFUDC offset on that which is included in CWIP, as permitted in Case No. U-5281.[12] 7 Tr 3350-3351.

The ALJ did not specifically speak to this particular issue in the PFD; however, she adopted the Staff's proposal in the figures set forth in Appendix C of the PFD.

In its exceptions, DTE Electric continues to argue that it is inconsistent to permit a return on capitalized AFUDC in plant, but not on AFUDC in CWIP. DTE Electric believes that the Staff is confused on this concept. DTE Electric's replies to exceptions, pp. 70-71. In its replies to exceptions, the Staff quotes DTE Electric's testimony that "what's called an AFUDC offset reverses the impact of AFUDC, so the idea is that [DTE Electric does not] get to recover return

[12] DTE Electric refers to the March 14, 1980 order in Case No. U-5281 (1980 order). In relevant part, ordering paragraph A of the order states: "For ratemaking purposes, an AFUDC offset to CWIP allowed will continue to be determined as an adjustment to net operating income." In relevant part, ordering paragraph B states: "The AFUDC rate utilized shall be the Commission's found overall rate of return for each utility. In the case of combination utilities' common plant, the AFUDC rate for such common plant shall be the latest overall rate of return for a major utility department." 1980 order, pp. 75-76.

twice . . . ." Staff's replies to exceptions, p. 14; 3 Tr 184. The Staff further argues that DTE Electric has not correctly interpreted the decision in the 1980 order. *Id*.

The Commission is not persuaded by DTE Electric's argument on this issue and finds no inconsistency in the policy. The Commission further finds that the Staff has correctly interpreted the 1980 order and has properly projected its adjustment to net operating income in this case to offset AFUDC included in CWIP until those items are closed to plants in service. Accordingly, the Staff's projected total AFUDC offset of $34.896 million is adopted.

10. Depreciation and Amortization Expense

DTE Electric initially projected depreciation and amortization (D&A) expense for the test year of $949 million. The company testified that the increased D&A was largely due to $170 million associated with the change in depreciation rates[13] and $138 million for capital in-service movement with offsets due to $47 million for plant retirements and $10 million from other regulatory assets being fully amortized before the test year. 7 Tr 3306; 8 Tr 4041; Exhibit A-13, Schedules C1 and C6.

In its initial brief, in accordance with the December 6 order, DTE Electric reduced its projected D&A expense by $65.39 million (this includes a reduction of $151,000 in depreciation related to the HQ Energy Center contingency amount) to reach a new projected D&A expense of $883.59 million. DTE Electric's initial brief, pp. 91-92; Attachment A, p. 3.

The Staff recommended that the company's projected depreciation rates be reduced on two counts: $12,138,000 resulting from the Staff's adjustments to DTE Electric's historic and

[13] This "change in depreciation rates" occurred prior to the settlement agreement approved by the December 6, 2018 order in Case No. U-18150 (December 6 order) which provided for additional changes in depreciation rates.

projected capital expenditures[14] and $175,795,000 to incorporate current depreciation rates.[15] 8 Tr 4041-4042; Exhibit S-3, Schedule C-1, and S-7.5.

The ALJ recommended adoption of a total D&A projection of $875.90 million. PFD, p. 174; PFD, Appendix C, Column H, Line 32.

In its exceptions, DTE Electric asserts that, after all appropriate adjustments are made, its correct total D&A projection is $883.5 million. The company also points out that the ALJ refers to Appendix A, p. 3, which does not exist.[16] DTE Electric's exceptions, p. 69. The Staff replies that the ALJ's calculations took into account her various proposed disallowances. The Staff argued that, subject to any changes that the Commission wishes to make, the ALJ's calculations pertaining to D&A are accurate. Staff's replies to exceptions, p. 15.

The Commission adopts the Staff's proposal to incorporate current depreciation rates, and approves D&A expense consistent with the decisions contained in this order.

11. Tax Expense

a. Property and Other Tax Expense

The ALJ noted that there appeared to be no dispute regarding the amount of property and other tax expenses for the test period, calculated by the company to be $275.5 million in property taxes and $52.2 million in other taxes. She recommended that the Commission adopt DTE Electric's

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[14] *See*, 8 Tr 4038, Figure 1.

[15] The Staff explained that DTE Electric filed its rate case using depreciation rates that were pending in Case No. U-18150, but not approved at the time the Staff prepared its filing. Accordingly, the Staff initially used the rates approved by the June 16, 2011 order Case No. U-16117.

[16] The correct citation is Appendix C, Column H, Line 32.

figures. PFD, p. 175. No exceptions were filed. The Commission adopts the findings and recommendations of the ALJ.

b. Federal Income Tax Expense

The ALJ stated that differences between DTE Electric's federal income tax (FIT) projection and the Staff's FIT projection are related to adjustments that the Staff made to the case. She noted that, according to DTE Electric, the company and the Staff appear to be in agreement regarding the effects of the TCJA on FIT. PFD, p. 175.

In its exceptions, RCG argues that "the inescapable conclusion" is that the ALJ erred when she relied solely on "Staff Witness Pung" to justify the addition of the $148.237 million to DTE Electric's revenue deficiency as set forth in Appendix A to the PFD, line 11.[17] RCG's exceptions, p. 9. RCG contends that there must be an error because DTE Electric asserted its overall revenue deficiency is $250.2 million, but the ALJ found it to be $261.904 million.[18] Further, RCG contends that neither Credit A nor Credit B adjustments should be included in this case because the Commission has issued separate orders to fully address the TCJA impacts. *Id.*, pp. 9-10. The Staff replies that Credit A should expire when the Commission approves new rates in this case and reiterates that DTE Electric could not include Credit A in its application in this case because Credit A was not yet in effect. Staff's replies to exceptions, pp. 47-48. In its exceptions, DTE Electric asserts that RCG seems to misunderstand the effect of the elimination of Credit A on revenue deficiency as set forth by the ALJ. DTE Electric's replies to exceptions, pp. 5-6.

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[17] *See*, 8 Tr 4281. Staff Witness Pung's testimony related to the decrease in DTE Electric's expected sales revenues because of rates approved by the July 24, 2018 order Case No. U-20105 (July 24 order), which is the company's TCJA Credit A case. Exhibit S-6, Schedule C3.

[18] *See*, Appendix A to the PFD, line 12.

The Commission is not persuaded by RCG's exceptions and finds that the ALJ's recommended adjustment of $148.2 million attributed to "Staff Witness Pung" in Attachment A of the PFD, line 11, is not only supported by Mr. Pung's testimony and calculations, but is reasonable and prudent as well. His explanation is clear that "it was necessary for newly approved rates to be used in calculating projected revenues" in this case, indicating that DTE Electric filed its case with calculations completed prior to the new rates approved by the settlement in the company's Credit A case.[19] 8 Tr 4281. Further, the Commission is cognizant that reduced rates due to the effects of the TJCA result in reduced revenue to the company that must be included in the rate case calculations when the credit expires. Accordingly, the Commission adopts the Staff's calculation of the effects of the TCJA and the ALJ's figures relating to the TCJA as set forth in Appendix A to the PFD, line 11.

B. Adjusted Net Operating Income Summary

In summary, the Commission finds that DTE Electric's jurisdictional projected NOI for the 2019-2020 test year is $842,172,000.

VI. <u>OTHER REVENUE-RELATED ISSUES</u>

A. Electric Vehicle Pilot (Charging Forward)

DTE Electric proposed an electric vehicle (EV) pilot (Charging Forward) which is a three-year set of projects developed after meetings with stakeholders and participation in the Commission's electric vehicle technical conference. 8 Tr 3563-3564. The company's proposal will cost approximately $13 million, including O&M, through the end of 2021. 8 Tr 3579. Overall, the parties did not object to the pilot but made several recommendations for modifications. The ALJ

[19] *See*, July 24 order.

reviewed each of the proposed modifications, in detail, in the PFD at pages 182-214, which are also addressed individually below.[20]

1. School Bus Pilot

As proposed, Charging Forward included a limited school bus pilot program which the Staff recommends should be greatly expanded beyond the "make ready" infrastructure proposed by the company. 8 Tr 3412. The expansion was supported by ChargePoint and ELPC, yet opposed by DTE Electric.

The ALJ found that the Staff's expansion proposal was reasonable. PFD, pp. 182-183. She concluded that the school bus pilot should be expanded, and that the costs involved with implementing new technology should not fall on the school systems. *Id*., p. 184.

In exceptions, DTE Electric again opposes the expansion of the school bus pilot program. Specifically, the company states that, while the pilot is important, expansion is premature and its "initial objective will be to find school districts that are willing to add electric buses to their fleets." DTE Electric's exceptions, p. 80.

MEC/NRDC/SC reply, arguing that the school bus pilot should be expanded and that the financial risk should not be passed on to the school districts. They also argue that it is not premature to expand the pilot and the funding because the Michigan Department of Environmental Quality (DEQ) "is also already handling Michigan school districts' grant applications for electric

[20] The Commission notes that DTE Electric agreed to the Staff's proposal to close the D1.9 Option 2 flat fee to new enrollment and phase it out, to keep rebate amounts flexible, and to submit annual summary reports (which will include information on the level of rebates used for the different categories of the charging infrastructure enablement component of the program). 8 Tr 3618-3620; PFD, p. 178, n. 418, and pp. 179-180. The Commission approves these agreed-upon changes to the Charging Forward program.

bus funding . . . ." MEC/NRDC/SC's replies to exceptions, p. 39. Therefore, MEC/NRDC/SC state that the ALJ's recommendation should be adopted by the Commission.

The Commission finds that DTE Electric's argument is reasonable. At this early stage, an expansion is not warranted and the company should be permitted to find participating school districts before additional expenditures are made. MEC/NRDC/SC's contention that the DEQ is reviewing grant applications bolsters the company's resistance to additional funding, at this time, given that districts may have an additional source of funds. At this stage, it is not clear which districts are willing to participate or what funding those districts will have available. The Commission is not persuaded, therefore, to require an expansion of the school bus pilot, or approve additional funding for the expansion at this time.

2. 80 Amp Charging Pilot

The Staff recommended that the Commission should approve an additional pilot with regard to 80 amp chargers as it "is an emerging charging technology that has not been extensively vetted by an electric utility in Michigan." 8 Tr 3413. ChargePoint reasoned that the Commission should take a "technology-agnostic" stance to explore varying innovations and the company argued that an additional pilot is not necessary. 7 Tr 3061; 8 Tr 3615.

The ALJ concluded that the Commission should "take a technology neutral position" and "permit the involved parties to determine what arrangements and technologies best meet their needs." PFD, p. 185. No party took exception to the ALJ's recommendation to take no action on the Staff's proposal. The Commission adopts the findings and recommendations of the ALJ.

3. Future-Proofing

Many parties argued that it would be prudent for the company to future-proof upstream charging infrastructure; future-proofing refers to the inevitable need to upgrade to ultra-fast charging rates. 8 Tr 3414. DTE Electric noted that "[t]o the extent 'future-proofing' is possible and reasonable . . . the Company will do so." 8 Tr 3615.

The ALJ found that DTE Electric should be proactive in its attempts to future-proof but that "it does not appear that the Commission can provide additional guidance." PFD, p. 189. Exceptions were not filed on this issue and the Commission adopts the findings and recommendations of the ALJ.

4. Sale-for-Resale

The Staff recommended that the Commission require the removal of tariff provisions on "sale-for-resale" that prohibit site hosts from charging customers on a per kWh basis. This position was supported by MEC/NRDC/SC, ChargePoint, and MEIBC/IEI. DTE Electric opposed the recommendation and contended that such a requirement would exceed the Commission's authority.

The ALJ found that allowing DTE Electric "to retain its sale-for-resale prohibition would remove a valuable tool from Charging Forward's toolbox of pilot program options that should be available to site hosts and DTE Electric." PFD, p. 194. She concluded that the revision of a tariff is directly within the Commission's authority to regulate, including the enforcement of reasonable rates and charges under *Union Carbide Corp v Public Service Comm*, 431 Mich 135; 428 NW2d 322 (1988) (*Union Carbide*). Specifically, the ALJ stated that "the Commission is called upon to amend a DTE Electric tariff provision that Staff and Intervenors find unreasonable" and she concluded that "the Commission has full authority to grant that request." PFD, p. 195. Therefore, the ALJ recommended that the company should be instructed to modify its tariffs to permit sale-for-resale by site hosts.

In exceptions, DTE Electric argues that the ALJ's recommendation to remove the sale-for-resale provision exceeds the Commission's authority, that allowing volumetric pricing could create confusion for its customers, and that site hosts should not be limited to charging on a per kWh basis. DTE Electric specifically contends that modifying the tariff provision is "contrary to the fundamental business structure that the Company envisioned for the Charging Forward Program." DTE Electric's exceptions, p. 73. Therefore, the company argues that the adoption of this recommendation would be contrary to the court's holding in *Union Carbide*. The company concludes that the prohibition on sale-for-resale is not problematic and should remain in place.

The Staff replies, contending that the company misapplied *Union Carbide* regarding the sale-for-resale provision. The Staff states that MCL 460.54 and MCL 460.6 provide the Commission with broad ratemaking authority which directly applies to the modification of tariff provisions. The Staff also notes its support for MEC/NRDC/SC's arguments as quoted by the ALJ and concludes that the Commission should adopt the ALJ's recommendation and "direct the Company to amend its tariffs to state that the sale of electricity for vehicle charging purpose is not considered a sale for resale." Staff's replies to exceptions, p. 32.

In reply, the Attorney General states that "if EVs are to truly be moved forward in a collaborative manner, then transparency and ease for EV drivers and EV charging station site hosts must be preserved." Attorney General's replies to exceptions, p. 28. She states that the company's *Union Carbide* arguments lack merit and that the amendment of DTE Electric's tariff is within the Commission's discretion. Therefore, the Attorney General requests that the Commission reject DTE Electric's exceptions and recommends the removal of the sale-for-resale prohibition.

MEC/NRDC/SC also reply, stating that the removal of the prohibition on sale-for-resale is supported by several parties and "is a matter of common practice across the country." MEC/NRDC/SC's replies to exceptions, p. 40. They argue that this change in the tariff would support the success of the pilot. MEC/NRDC/SC also state that no party argued to exclusively limit site hosts to charging on a per kWh basis, but to allow it as an additional option rather than a limitation. Further, they argue that DTE Electric's *Union Carbide* argument is without merit.

In reply, ChargePoint argues that DTE Electric's concern about customer confusion is unfounded. ChargePoint explains that "more than half of the States have already addressed this non-controversial issue without creating widespread customer confusion." ChargePoint's replies to exceptions, p. 3. ChargePoint further states that DTE Electric mischaracterizes the recommendation to remove the prohibition on sale-for-resale as a limitation upon site hosts.

The Commission agrees with the Staff, the Attorney General, MEC/NRDC/SC, ChargePoint, MEIBC/IEI, and the ALJ, and finds that DTE Electric should be required to file amended tariffs allowing sale-for-resale for commercial EV charging site hosts. The contention that volumetric pricing would be confusing for customers is not supported on the record. The Commission adopted a similar tariff change in the February 28, 2017 order in Case No. U-17990 (February 28 order), wherein the Commission held that "the sale of electricity by charging station owners should not be treated as a resale of electricity under the tariff, or as a sale by regulated utilities." February 28 order, p. 160. The Commission finds that consistency between the utilities will lessen confusion for both site hosts and EV customers rather than cause confusion as the company contends.

DTE Electric also contends that retaining the sale-for-resale prohibition is a managerial decision with which the Commission cannot interfere under *Union Carbide*. The Commission disagrees and finds that the company's argument is without merit. The Commission has broad ratemaking authority under MCL 460.54 and MCL 460.6, and the Commission finds that the modification of a tariff does not exceed its jurisdiction or authorized powers. As discussed by the ALJ, the court in *Union Carbide* specifically held that the Commission has the authority to regulate and enforce reasonable rates and charges and the amendment of a tariff provision is squarely within the Commission's authority. PFD, pp. 194-195. Therefore, the Commission adopts the findings and recommendations of the ALJ.

5. Demand Charges

MEC/NRDC/SC and MEIBC/IEI expressed concern with the demand charges associated with DC fast charger (DCFC) charging station usage. Specifically, they argue that the Commission should implement a demand charge holiday because, under Rate Schedule D4, a monthly demand charge for DCFC site hosts could exceed $2,500. *See*, 6 Tr 2216-2217. The Staff agreed, in part, stating that during the early stages of Charging Forward there may be benefits associated with a demand charge holiday. However, the Staff also stated that the holiday should be specific and not permanent. 8 Tr 4255. DTE Electric argued that the demand holiday issue is moot as commercial customers have multiple available rates which do not have demand charges and the customer should be able to choose which rate is best for their individual needs. 8 Tr 3624.

The ALJ found that "demand charges pose a significant and unnecessary economic impediment to the successful deployment of publicly available [DCFC] charging stations." PFD, p. 198. Therefore, the ALJ recommended that the Commission adopt the Staff's proposal for a demand charge holiday for up to five years.

DTE Electric excepts, arguing that the ALJ misunderstands DTE Electric's rate schedules. The company explains that Rate Schedule D1.9 does not have a demand charge and is available to both residential and commercial customers, and that commercial customers can also choose the D3 General Service Rate or the D3.3 Interruptible General Service rate which do not have demand charges.

The Staff also takes exception arguing that the ALJ's recommendation to create a demand charge holiday should be modified "to add language to tariff D3 stating that the 1000 kW [kilowatt] demand cap for the tariff does not apply to EV fast chargers until June 1, 2024." Staff's exceptions, p. 10. The Staff further states that the adoption of the same would not be detrimental to the company because the effects should be minimal given the adoption of the EV rates.

The company filed replies to the Staff's exceptions stating that the Staff's suggestion is meritless because there is "no specific demand 'cap' in the Rate D3 tariff language, and thus no changes are necessary to the tariff to allow customers with a load 1000 kW and larger to sign up on the rate." DTE Electric's replies to exceptions, p. 39.

MEC/NRDC/SC also reply, stating that it is the company's obligation to offer rates which not only reflect reasonable costs but also accommodate the evolving uses of the electricity grid, and that DTE Electric fails to recognize the limitations of its existing rates. They contend that DTE Electric's D3 rate schedule "is not available to customers with annual demand that exceeds 1,000 kW" which is "unlikely to be workable in cases where multiple DCFC are installed . . . ." MEC/NRDC/SC's replies to exceptions, p. 43. MEC/NRDC/SC reiterate that, under the D4 rate schedule, site hosts risk incurring large demand charges. Therefore, they argue that the Commission should adopt a demand charge holiday to provide ratepayers with more reasonable options.

The Commission finds that the ALJ's recommendation to implement a limited demand charge holiday is reasonable. While the company argues that this issue is moot, the record reflects that the D3 General Service Rate schedule is expected to be the primary choice for site hosts and that it "is limited to a load of 1000 kW (or possibly slightly more, according to the tariff) . . . ." 8 Tr 3624, 4255. Further, the D4 Large General Service Rate would likely result in significant demand charges for potential site hosts. The Commission finds that the ALJ properly described DTE Electric's current offerings as "a significant and unnecessary economic impediment to the successful deployment of publicly available [DCFC] charging stations." PFD, p. 198. Specifically, the load limitation in the D3 tariff, as described by the Staff, and the demand charges set forth in the D4 tariff, could deter potential site hosts from installing DCFC charging stations. Therefore, the Commission adopts the findings and recommendations of the ALJ to implement a demand charge holiday for site hosts. More specifically, the Commission finds that DTE Electric shall add language to tariff D3 stating that the 1000 kW demand cap for the tariff does not apply to EV fast chargers until June 1, 2024.

6. DC Fast Charger Price Regulation

Like the demand charge holiday, MEC/NRDC/SC and MEIBC/IEI contend that the Commission should implement consumer protections such as a pricing limitation in the early stages of the program, noting that a reasonable standard would be to tie the cost per charge roughly to the cost of one gallon of gasoline. 6 Tr 2217-2218. The Staff and DTE Electric disagreed and stated that the Commission should not regulate charging rates or impose a specific standard. MEC/NRDC/SC further argued that the company should work with site hosts to provide reasonable rates which are appropriate for the market, similar to Consumers' approach in PowerMIDrive. MEC/NRDC/SC's initial brief, p. 87.

The ALJ found that the most reasonable solution was presented by MEC/NRDC/SC and recommended that the Commission adopt the same consumer protection measures that were approved in Case No. U-20134. PFD, p. 201.

DTE Electric takes exception and contends that the ALJ's recommendation needs to be clarified. The company notes its agreement with reasonable rates for DCFC charging which is consistent with the January 9, 2019 order in Case No. U-20134. However, the company disagrees with the ALJ's statement that MEC/NRDC/SC provided the most reasonable solution because the record reflects their position includes a specific standard, which the company opposes. DTE Electric argues that at this early stage specific standards for pricing should not be imposed. DTE Electric's exceptions, pp. 83-84.

The Staff also filed exceptions seeking clarification of the ALJ's recommendation. Like the company, the Staff argues that MEC/NRDC/SC's recommendation for a specific standard such as setting the cost of charging comparable to the cost of gasoline is not appropriate. The Staff argues that this position should be rejected but agrees that the language from the settlement in Case No. U-20134 "provides a reasonable approach to price regulation . . . ." Staff's exceptions, p. 12.

In reply, ChargePoint agrees with the company and the Staff, stating that the ALJ's conclusion is somewhat unclear. The settlement in Case No. U-20134 does not include a requirement that DCFC chargers be regulated according to the cost of gasoline. ChargePoint argues that preemptively regulating prices would be detrimental to the pilot program and that if pricing becomes a problem, the Commission can address the problem at a later date. Therefore, ChargePoint agrees that the ALJ's recommendation should be clarified. ChargePoint's replies to exceptions, pp. 2-3.

The Commission agrees with DTE Electric, the Staff, and ChargePoint that the ALJ's recommendation is not fully reconcilable. The Commission finds that MEC/NRDC/SC's testimony includes very specific recommendations such as tying the cost per charge roughly to the cost of one gallon of gasoline, which the ALJ found to be inappropriate. PFD, p. 201. The Commission agrees with the ALJ's finding that a specific standard is not reasonable. Nevertheless, it disagrees that MEC/NRDC/SC set forth the most reasonable solution, as also stated by the ALJ, given the recommendation regarding specific pricing standards. Notwithstanding, the ALJ's determination that consumer protection measures should be imposed, is well taken by the Commission. The Commission finds that DTE Electric shall work with potential site hosts to educate them on available rates, discuss benefits, and assist in determining reasonable and market-based pricing options, while also providing the site hosts flexibility and authority to set rates based on their individualized needs.

7. Level 2 Metering Options

The Staff recommended that the company add additional provisions to Rate Schedule D1.9 including the addition of submetering options to address the lack of enrollment in the EV TOU rate. 8 Tr 3417-3420. The Staff recommended that DTE Electric file an application within 30 days of the date of this order to amend Rate Schedule D1.9, proposing submetering options to be piloted by the Charging Forward program. 8 Tr 3420. DTE Electric opposed the recommended change arguing that it would be premature to require the modification.

The ALJ concluded that DTE Electric's objections were based upon a misunderstanding of the Staff's recommendation as the Staff "is merely proposing to make it an option, at DTE Electric's discretion." PFD, p. 203. Therefore, she concluded that the Commission should order the company to add tariff amendments to incorporate the Staff's advanced metering options, at the company's discretion.

No exceptions were filed and the Commission adopts the findings and recommendations of the ALJ. The Commission finds that, within 60 days of the date of this order, DTE Electric shall file an application to amend Rate Schedule D1.9, proposing additional metering options discussed by the Staff on this record. 8 Tr 3417-3420.

8. Reporting Requirements and Technical Conferences

The Staff recommended that the Commission require the company to file a status report prior to the implementation of the pilot and a report every 12 months, and further stated that it will hold a technical conference after each filing. 8 Tr 3420. The company generally supported the Staff's proposal but objected to the status report before implementation, arguing that the record "will provide all the information stakeholders need prior to implementation." 8 Tr 3620.

The ALJ agreed with the Staff and recommended that the Commission require the company to file a status report, prior to the implementation of Charging Forward, so that all interested persons and the Commission are aware of the scope and nature of the program, in addition to the agreed upon annual reports. PFD, p. 206.

No exceptions were filed and the Commission adopts the findings and recommendations of the ALJ.

9. Increased Budget

The Staff recommended an increased budget and an expansion of several of the Charging Forward pilot programs, such as the school bus pilot discussed above. DTE Electric opposed the increased budget and expansion arguing that the Staff's proposals are premature and the company would prefer to implement a successful pilot before expansion. 8 Tr 3613.

The ALJ recommended that the Commission adopt the Staff's proposed $6 million budget increase in order to cover the proposed expanded school bus pilot, to expand the number of DCFCs beyond the 32 proposed, and to provide additional human resources to implement the programs. PFD, pp. 209-210.

DTE Electric takes exception to the ALJ's adoption of the Staff's proposal to increase the funding by $6 million. "The Company believes it is premature to increase funding and prefers to ensure it is on target to implement a successful program before it proposes increases in scope and budget to Charging Forward." DTE Electric's exceptions, p. 79. DTE Electric notes its agreement that the school bus pilot is important but states that initially the company must identify school districts willing to participate prior to expanding the scope. Further, DTE Electric argues that the most important part of the pilot, at this stage, is to increase the number and accessibility of chargers.

In reply, MEC/NRDC/SC dispute the company's exceptions and argue that the evidence on record demonstrates that the company will need additional resources to develop a fast charging network, to uncap rebate levels, to future-proof, and to expand the school bus pilot program. MEC/NRDC/SC conclude that "there is no shortage of reasons for the Charging Forward budget to be increased." MEC/NRDC/SC's replies to exceptions, p. 39.

The Commission agrees with the company that the expanded funding and programming is not warranted, at this time. As indicated above, the Commission agrees with the company that it is premature to expand the school bus pilot and authorize additional funding. The Commission further finds that the company should be permitted to implement the pilot and evaluate its strengths and weaknesses before being required to expand the program. The company will be working closely with the Staff and interested persons through reporting and technical conferences during the implementation and development of Charging Forward. Therefore, the need for additional funding can be evaluated throughout the program and addressed in a future case.

10. Cost Recovery

The company proposed the pilot program costs be recovered through capital expenditures, O&M expense, and regulatory asset treatment for proposed rebates. 8 Tr 3579-3581. The Staff, however, recommended deferral of both rebates and O&M costs through the creation of a regulatory asset with amortization over a five-year period. 8 Tr 4056-4057. The company agreed in rebuttal "to treat costs related to capital expenditures above the capital reflected in this case as a regulatory asset." 8 Tr 3614.

The Staff recommended three performance objectives for the Charging Forward Program for DTE Electric: (1) 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 ratepayers; and (3) ensure that investments in make-ready infrastructure serve double duty by directly addressing core barriers (such as range anxiety), and by enabling 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. DTE Electric agreed to incorporate these elements. 8 Tr 3621.

The ALJ noted that DTE Electric also agreed with the Staff's recommendation to treat the O&M expenses as a regulatory asset. Therefore, she recommended that the Commission adopt the Staff's proposal, stating that "it protects customers from paying for costs that might not be incurred" and allows the company "to fairly recover its costs actually incurred." PFD, p. 213.

The company takes exception to the ALJ's recommendation to adopt the Staff's proposal for regulatory asset treatment. DTE Electric specifically states that it objects to the "Staff's proposals to (1) begin amortization the year after the costs are incurred, and (2) delay recovery of the unamortized balance until after Staff's review." DTE Electric's exceptions, p. 75. The company contends that it could lose recovery of some deferred costs which are amortized due to regulatory lag and that it "should not have to absorb the expenses for the Charging Forward program." *Id.*, p. 76. In addition, DTE Electric contends that the ALJ misunderstood its position with regard to the regulatory asset treatment. Specifically, the company states that it proposed the O&M expenses be recovered as base O&M and not be deferred and "the lack of certainty on cost recovery could delay the implementation of this aspect of the program." DTE Electric's exceptions, p. 78.

The Commission finds that the ALJ's recommendation is well reasoned and supported on the record. Although the company has clarified that it does not agree with delaying recovery of the O&M expenses through regulatory asset treatment, the Commission finds that the Staff's proposal for regulatory asset treatment, including O&M, is the most reasonable. The Commission further adopts the three performance based objectives articulated by the Staff. 8 Tr 3420-3421, 3621. The Commission also finds that a five-year amortization period beginning the year following cost deferral is appropriate. DTE Electric objects, stating that it could lose recovery of some deferred costs due to regulatory lag. However, DTE Electric made this argument, in part, based upon its reliance on approval of its requested IRM, given that such approval would likely delay the filing of its next rate case. As discussed below, the Commission declines to approve the proposed IRM. As such, the company's contention that its next rate case will be delayed until 2022 is unlikely thereby reducing its risk of lost recovery. Nevertheless, the Commission finds that regulatory asset treatment is still preferred as it balances the risk between the company and the customer.

The Commission finds that the creation of a regulatory asset for Charging Forward expenses is consistent with the Commission's cost recovery approval in Case No. U-20134. Overall, the Commission finds that regulatory asset treatment, as proposed by the Staff, is the most reasonable and prudent recovery mechanism. Regulatory asset treatment balances the company's interest with customer protection, by not requiring customers to pay for expenses that may not be incurred and by allowing the company to recover the actual costs incurred. As such, the Commission finds that DTE Electric is authorized to create a regulatory asset to recognize deferred EV program costs with the amortization of those costs over five years beginning the year after the costs are incurred. Further, the Commission authorizes the company to include recovery of the resulting amortization expense in rates and include the deferred net unamortized balance of EV program costs in rate base. However, the program costs will not actually be recovered until they have undergone a future reasonableness-and-prudence review in a rate case. The Commission also adopts the ALJ's recommendation for DTE Electric to examine whether there would be cost savings associated with the use of a tracker for future rebate programs as compared to regulatory asset accounting.

B. Infrastructure Recovery Mechanism

DTE Electric proposed an IRM with a total revenue requirement of nearly $824 million. The company contended that "with the proper IRM in place for the intervening years, it may be able to defer filing for a rate increase until sometime in 2022 for new base rates in 2023." 3 Tr 75. The Staff contends that the IRM could result in a significantly larger regulatory burden. 8 Tr 4163-4164. Additionally, the Staff stated that it is not clear what value will be returned if the IRM is approved, yet it will result in guaranteed rate increases.

The ALJ found that the company failed to demonstrate the reasonableness of the proposed IRM expenses or that ratepayers would receive any benefit from the IRM, if approved. PFD, p.

217. She specifically stated that the IRM "is too expensive, too expansive, and allows the company far too much discretion in spending before any review of reasonableness and prudence occurs" and therefore recommended that the Commission deny the proposed IRM. PFD, p. 218.

In exceptions, DTE Electric argues that the parties do not recognize the extensive proceedings establishing DTE Gas' meter move out (MMO) program, main renewal program (MRP), and pipeline integrity (PI) program,[21] and various cost recovery trackers which have been affirmed by the Court of Appeals. DTE Electric contends that the ALJ's criticism of the proposed IRM is unfounded and reiterates the proposed expenditures. The company also restates that the IRM may allow it to delay filing a for a rate increase until 2022 and that it will work to ensure that the funds are spent efficiently. Specifically, the company states that it:

> proposes to (1) meet with the Staff each fall to review expected IRM expenditures and the scope of IRM work to be accomplished for the upcoming IRM year, (2) provide Staff with a summary of actual work completed (Program Metrics) in each reconciliation, (3) report performance indicators to the Staff annually, and (4) meet with the Staff throughout the year to review progress relative to the plan.

DTE Electric's exceptions, pp. 91-92. DTE Electric concludes that the approval of an IRM is well-established in the law and the proposal set forth is "well designed and fully supported" and should be approved by the Commission. *Id.*, p. 92.

In reply, the Attorney General contends that the ALJ properly denied DTE Electric's IRM request. She notes that merely because the Commission authorized this type of funding in the past, does not mean that the Commission is required to authorize an IRM in this case. Further, the Attorney General argues that DTE Electric indicates that it "may" be able to delay its next rate case until 2022, yet provided no assurances; therefore, this assertion should be ignored. She also states that the company makes additional empty assertions regarding projects and expenses to be

[21] The company refers to these programs collectively as DTE Gas' IRM.

included in the proposed IRM, but that infrastructure improvements should be approved through traditional ratemaking where the Commission can review the reasonableness and prudence of the proposed costs. Accordingly, the Attorney General requests that the Commission adopt the PFD and "reject the Company's request for this unbridled, expansive IRM." Attorney General's replies to exceptions, p. 31.

MEC/NRDC/SC also reply to DTE Electric's exceptions, stating that the record lacks any evidentiary basis to support the "expensive, expansive, and discretion-laden IRM." MEC/NRDC/SC's replies to exceptions, p. 45. MEC/NRDC/SC contend that the company's exceptions are merely a recitation of its previous contentions and that the company has failed to provide evidence to support its unprecedented IRM request.

In reply, ABATE contends that DTE Electric's reliance upon *In re Applications of Detroit Edison Company*, 296 Mich App 101; 817 NW2d 630 (2012) is in error, because the court in that case approved trackers based on actual past expenses. ABATE contends that DTE Electric's request in this case differs because it "is based on future projections and not actual costs" and the cited "decision gives absolutely no credence to [the company's] argument that the case law supports an IRM." ABATE's replies to exceptions, p. 11.

The Commission is receptive to considering an IRM with the proper oversight, legal structure, and performance-based regulation framework including customer protections. Given the level of planned capital investment in electric distribution and generation over the next few years, the IRM as proposed by DTE Electric is significant. While the Commission recognizes that this scale may be necessary in order to achieve DTE Electric's stated objective to defer regular rate cases, the Commission finds that the proposed IRM is overreaching and not adequately supported. As the ALJ aptly stated, the company's request "is too expensive, too expansive, and allows the company far too much discretion in spending before any review of reasonableness and prudence occurs." PFD, p. 218. The Commission agrees and finds that the company has failed to demonstrate that the proposed revenue requirement of nearly $824 million is either reasonable or prudent. Based on the evidence in this proceeding, there is inadequate specificity and justification for investment of this magnitude, particularly for the fossil and nuclear generation portions of the proposed IRM. The Commission observes that an IRM of this magnitude would need outcome and output-based performance metrics and corresponding ratepayer protections, as the Staff and other parties suggested.

In light of the above discussion, the Commission adopts the findings and recommendations of the ALJ.

C. Nuclear Surcharge

DTE Electric proposed a nuclear surcharge of $38.285 million, an increase of $2.725 million, utilizing updated calculations which were approved in its three prior rate cases. 5 Tr 1293; Exhibit A-20, Schedule J1. The company's proposal does not change the nuclear decommissioning funding portion of the surcharge, increases the low-level radioactive waste (LLRW) disposal funding by $2 million, and increases the site security and radiation protection (SSRP) funding by $725,000. *See*, Exhibit A-20, Schedule J1. ABATE explained its concern that the company's calculations were based on outdated data, excessive inflation rates, and high decommissioning costs. 7 Tr 2856-2858. The Staff calculated the nuclear surcharge using the same methodology as the company. 8 Tr 4286.

The ALJ recommended that the Commission approve the increased surcharge but also require the company to "provide an updated decommissioning study in its next rate case, or in a stand-alone proceeding as has been done in the past." PFD, p. 221.

DTE Electric takes exception to the ALJ's recommendation and argues that, while the ALJ properly agreed with the company's proposal to increase the nuclear surcharge, she erred in recommending that the approval should be subject to the condition of submitting an updated decommissioning study in the future. DTE Electric's exceptions, p. 93. Specifically, the company cites *Detroit Edison Co v Public Service Comm*, 264 Mich App 462; 691 NW2d 61 (2005), to contend that the Commission cannot approve costs subject to a future condition and further argues that an updated decommissioning study is unnecessary. The company continues, claiming that the decommissioning cost estimate complies with regulations and is "reasonable and complete" based on "what is presently known." DTE Electric's exceptions, p. 94. DTE Electric concludes by stating that it should not be burdened by being required to submit another report which would not provide benefit to the Commission given that SSRP expenses are scrutinized on a regular basis.

The Attorney General also takes exception and argues that the Commission should reject DTE Electric's proposed increase to the nuclear surcharge. She explains that the proposed amounts are "based on an outdated and generic study that dates all the way back to 1996." Attorney General's exceptions, p. 27. The Attorney General also agrees with the ALJ's recommendation to require the company to provide an updated decommissioning study in the next rate case but concludes that the recovery for the nuclear surcharge should be limited to the $35.6 million approved in the prior rate case. *Id*., pp. 28-29.

Like the Attorney General, ABATE takes exception to the ALJ's recommendation to approve the company's proposal to increase the nuclear surcharge. ABATE contends that the company should "only be allowed to recover $27.482 million through this surcharge." ABATE's exceptions, p. 11. ABATE also notes that the ALJ's recommendation to require the company to provide an updated decommissioning study is a step in the right direction but that the Commission should require DTE Electric "to have a third-party, such as TLG Services, conduct a completely independent and current estimate of the cost to fully decommission the Fermi 2 power plant." *Id*. ABATE states its two major concerns are that: (1) the company's 6% inflation rate is unsupported and is excessive, and (2) the nuclear decommissioning funding portion of the surcharge is excessive and based upon stale information. ABATE concludes that it has presented evidence demonstrating minor changes to the calculations, with reasonable assumptions, which demonstrates that DTE Electric has already collected required funds to cover the decommissioning costs and that the company has provided no rebuttal or justification for its use of inflated numbers. Moreover, ABATE argues that the excessive funds collected for decommissioning are sufficient to cover the LLRW expenses. With regard to the SSRP expense, ABATE argues that DTE Electric has not demonstrated that an increase is appropriate, and contends that the recovery should be limited to the historical levels approved in prior rate cases.

DTE Electric replies to the Attorney General and ABATE's exceptions, reiterating its contentions regarding the nuclear surcharge. The company again notes that the Staff calculated the proposed surcharge in the same manner and argues that the Staff agreed with the proposed increase. DTE Electric's replies to exceptions, p. 40. DTE Electric contends that it has justified the use of the 6% inflation rate in the record, including ABATE's Exhibit AB-7. The company also refutes ABATE's claim that a third-party decommissioning study should be performed as it contends it "already has a reasonable decommissioning cost estimate with more than a decade of Commission oversight supporting its central assumptions." DTE Electric's replies to exceptions, p. 44.

The Attorney General also replies, explaining that the company should not be allowed to "keep receiving the current level of recovery based on an outdated, 23-year old study." Attorney

General's replies to exceptions, p. 32. She argues that DTE Electric has failed to support the requested nuclear surcharge and that the Commission should adopt the ALJ's recommendation to require an updated decommissioning study.

The Commission finds that the PFD is well-reasoned and appropriately recommends the approval of DTE Electric's proposed nuclear surcharge. The ALJ properly found that the company's and the Staff's evidence demonstrates that the $2.725 million increase is reasonable. The company updated the SSRP funding with 2017 historical expenses and inflation and the LLRW disposal funding was updated to reflect additional forecasted expenditures. 5 Tr 1294. While the Attorney General and ABATE dispute the company's use of the 6% inflation rate, the Commission finds that it is supported by evidence and testimony on record and is reasonable. *See*, Exhibit AB-7; 5 Tr 1322-1324. The Commission further finds that ABATE's contention that DTE Electric has already collected sufficient funds is not supported. As the company indicates, funds are not able to be easily reallocated as suggested by ABATE. Thus, the evidence and testimony on record support the ALJ's recommendation, and the Commission finds that the company's proposed nuclear surcharge is reasonable and is approved.

Notwithstanding the above, the Commission adopts the ALJ's recommendation to require DTE Electric to submit an updated decommissioning study. More specifically, the ALJ stated "ABATE presented compelling evidence that the assumptions underlying the calculation of the amount needed to decommission Fermi 2 may no longer be valid and should be revisited." PFD, p. 221. The Commission agrees and finds that the decommissioning cost estimate which is relied upon by DTE Electric was conducted in 2002, and, although it is reviewed annually, an updated study would be beneficial. The company does not dispute the age of the study and has failed to rebut ABATE's evidence reflecting a large disparity of funds held in trust for decommissioning when compared to other funds on a cost-per-kW basis. The company contends that "more exact estimates are timed closer to actual decommissioning." DTE Electric's exceptions, p. 94. However, ratepayers should not bear the burden of an outdated surcharge merely because the company intends to update its estimates someday prior to decommissioning. Given that the record demonstrates that the decommissioning amounts held in trust for Fermi 2 are roughly 50% more than other nuclear plant trust funds on a cost per kW basis, the ALJ's recommendation is reasonable and prudent. Therefore, the Commission finds that DTE Electric shall submit an updated decommissioning study as part of its next general rate case. The Commission also notes, contrary to the company's assertions, that the approval of funding in this case is not conditional upon submitting an updated decommissioning study in the future. Rather, the updated study will provide the Commission with additional information and guidance to review the proposed nuclear surcharges in the next rate case.

D. Accounting Requests

1. Program Evaluation and Review Committee Expense

In Case No. U-18014, the Commission approved $4.9 million in annual program evaluation and review committee (PERC) expenses, with deferral treatment for expenses over or under the $4.9 million. January 31, 2017 order in Case No. U-18014, pp. 74-75. DTE Electric spent $27 million in 2017, and expects to spend $31.5 million in 2018, $19.5 million in 2019, and $16.8 million in 2020 on PERC projects. *See*, Exhibit A-13, Schedule C5.16. The company explained that the increase was based, in large part, upon the 24-month operating cycle project. 5 Tr 1292-1293. The Attorney General recommended a disallowance of $2.9 million in amortization costs, arguing that it is speculative. 5 Tr 1600-1601.

The ALJ found that the Attorney General's argument was without merit and that the PERC expenses were supported by the evidence and testimony on the record. PFD, pp. 222-223.

No exceptions were filed and the Commission adopts the findings and recommendations of the ALJ.

2. Other Accounting Requests

DTE Electric requested regulatory asset treatment for certain C360 costs and ADMS costs. 7 Tr 3327-3329. The ALJ found that the company's request was disputed by the Attorney General, albeit without support. Therefore, the ALJ found the company's proposed regulatory asset treatment to be appropriate and recommended approval of the requests. PFD, p. 223. No party filed exceptions on this issue and the Commission finds that the ALJ's recommendation for approval of the regulatory asset treatment is reasonable and prudent. *See*, pp. 33-34, *supra*.

VII. REVENUE DEFICIENCY SUMMARY

The ALJ arrived at a total revenue deficiency of $261.904 million, of which approximately $113.6 million is the revenue deficiency arising from the decisions in the PFD. PFD, pp. 301.

In accordance with the findings in this order, DTE Electric's jurisdictional revenue deficiency for the test year is computed as follows:

Rate Base	$17,058,834,000
Adjusted Net Operating Income	$842,172,000
Overall Rate of Return	4.94%
Required Rate of Return	5.48%
Income Requirements	$934,862,000
Income Deficiency (Sufficiency)	$92,690,000
Revenue Conversion Factor	1.3496

Revenue Deficiency $125,097,000

With the expiration of the TCJA Credit A approved in Case No. U-20105, an additional impact to customers of $148,237,000 occurs, making the total net rate increase $273,334,000.

VIII. COST OF SERVICE

A. Transmission, Distribution, and Uncollectible Cost Allocations

DTE Electric's forecasted unbundled cost of service (UCOS) study proposed using the 12CP 100-0-0 (i.e., 100% demand) method of cost allocation for transmission costs. 7 Tr 3214, 3216; Exhibit A-16, Schedule F1.1. For distribution costs, the company proposed using three allocation bases: demand, customer, and those based on special studies (i.e., for allocating meters and uncollectible expense). 7 Tr 3217; Exhibit A-16, Schedule F1.2. DTE Electric's proposed allocation method for distribution then allocated these distribution costs by voltage level class (i.e., into residential secondary, commercial secondary, primary, sub-transmission, transmission, and lighting classes). And, for uncollectibles, the company proposed allocation of such costs based on net write-offs. 7 Tr 3219. According to DTE Electric, these allocation methods, including for production cost discussed below, are based on cost incurrence, and were the methods approved in the 2018 orders. 7 Tr 3216-3217, 3219.

Finding DTE Electric's proposed transmission, distribution, and uncollectible cost allocations to be undisputed in this case, the ALJ recommended that they be approved. PFD, p. 224.

No exceptions were filed. The Commission adopts the findings and recommendations of the ALJ.

B. Production Cost Allocation

DTE Electric's forecasted UCOS study used the 4CP 75-0-25 method of cost allocation for certain production-related costs—75% for demand, 0% for energy use coincident to the MISO on-peak period, and 25% for total energy use. 7 Tr 3210, 3216-3217.

The ALJ found merit in MEC/NRDC/SC's alternative recommendation to review DTE Electric's production cost allocation method in the company's next rate case,[22] and thus recommended that this issue be revisited in the company's next rate case or in a special purpose proceeding like Case No. U-17689. PFD, p. 228. In her analysis, the ALJ noted authority within MCL 460.11(1) to modify the 75-0-25 cost allocation method if it does not ensure COS-based rates, despite use of this cost allocation method for certain production-related costs in DTE Electric's last three rate cases (Case Nos. U-17767, U-18014, and U-18255). PFD, p. 228. The ALJ also highlighted what she found to be unrebutted and persuasive evidence of MEC/NRDC/SC regarding the current disproportionality of production costs allocated to different customer rate classes, DTE Electric's high residential rate, and the disparity between the company's allocations and the market prices of capacity and energy. PFD, p. 228; 6 Tr 2187-2192.

DTE Electric disagrees with the ALJ's recommendation and reiterates that there is no valid reason to revisit its cost allocation method for these production-related costs, as established in Case No. U-17689 and continuously applied in Case Nos. U-17767, U-18014, and U-18255. In support, DTE Electric recalls the rebuttal testimony of one of its witnesses (7 Tr 3234), repeats discussion about *res judicata* and collateral estoppel, and "objects to the extent that the [ALJ]

[22] With their alternative recommendation, MEC/NRDC/SC specifically recommended that DTE Electric be directed "to include in the COSS [cost of service study] for its next rate case an allocation based on the equivalent peaker method." MEC/NRDC/SC's reply brief, p. 67. MEC/NRDC/SC's primary recommendation was for the Commission to modify the company's production cost allocation in this case. *Id*. *See also*, 6 Tr 2191-2192, 2229-2230.

suggests that the Company has some burden to present an initial case, or otherwise re-prove the status quo." DTE Electric's exceptions, pp. 95-96. Relating to MEC/NRDC/SC's assertions, DTE Electric further argues that "'[t]he party alleging a fact to be true should suffer the consequences of a failure to prove the truth of that allegation'" and that "there is a heightened evidentiary presentation required for 'any party proposing to revise the production cost allocation method in a future case.'" DTE Electric's exceptions, p. 97, citing *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), and the January 31, 2017 order in Case No. U-18014, pp. 100-101.

Also disagreeing with the ALJ, ABATE asserts that the Commission should reject revisiting this issue in either DTE Electric's next rate case or in a special purpose proceeding. ABATE likewise recalls the rebuttal testimony of one of its witnesses (6 Tr 1772-1784) to underpin its assertion that the ALJ erred in her recommendation on this issue. ABATE's exceptions, pp. 17-21.

In replies to exceptions, the Staff quotes the relevant portion of MCL 460.11(1) and contends that the Commission, based on the last sentence in MCL 460.11(1), has discretion to decide what production allocator produces COS-based rates. Averring that the ALJ properly decided this issue based on the evidence presented in the case, the Staff thus asserts that ABATE's exceptions on this issue should be dismissed. Staff's replies to exceptions, pp. 44-45.

MEC/NRDC/SC maintain their position that DTE Electric's production cost allocation method does not ensure rates are cost-based, as required by MCL 460.11(1), and recall testimony and evidence in support. MEC/NRDC/SC state that the company, in exceptions, does not address the evidence relied upon by the ALJ in support of her recommendation but rather merely relies on the testimony of its witness that the Commission has continuously applied the 4CP 75-0-25 method in DTE Electric's last three rate cases since Case No. U-17689 and that there is no reason to reconsider or deviate from this methodology. MEC/NRDC/SC thus aver that DTE Electric's arguments "all boil down to the assertion that because the 4CP 75-25 method was adopted in Case No. U-17689 and affirmed in the next three rate cases, that method cannot ever be re-evaluated. This position is incorrect, for several reasons." MEC/NRDC/SC's replies to exceptions, pp. 50-51. MEC/NRDC/SC first reference, as noted by the ALJ, that MCL 460.11(1) "expressly contemplates re-evaluation of the method if there is evidence – as here – that it no longer ensures rates are equal to cost of service . . . ." *Id*., p. 51, citing PFD, p. 228. Second, according to MEC/NRDC/SC, the January 31, 2017 order in Case No. U-18014, pp. 100-101, demonstrates that "this issue has not been settled once and for all, as DTE claims. To the contrary, the Commission has expressed interest in evaluating the equivalent peaker method or a similar method, the rationale for which is similar to that of Mr. Jester's recommendation." MEC/NRDC/SC's replies to exceptions, p. 51. MEC/NRDC/SC aver that, contrary to DTE Electric's claims, their evidence is new and demonstrates that circumstances have changed since Case No. U-17689 and that the company's arguments are not well-taken. MEC/NRDC/SC state, "The ALJ's recommendation is a modest, incremental step towards examining this issue further, and it should be upheld." *Id*., p. 52.

MEC/NRDC/SC contend that ABATE primarily rehashes arguments previously raised and argue that ABATE's witness's criticisms of MEC/NRDC/SC witness's analysis are "inapt, unfounded, and should be given no weight." *Id*. Here, in addressing ABATE's assertion about MEC/NRDC/SC's witness seeming to have a fundamental misunderstanding about the COSS procedure and setting rates, MEC/NRDC/SC refer to their witness's credentials. MEC/NRDC/SC assert that, contrary to ABATE, under both scenarios presented by MEC/NRDC/SC's witness (6 Tr 2192), all embedded costs would be allocated. MEC/NRDC/SC next aver that ABATE's assertion about the uniqueness of Michigan with regard to COS ratemaking should be disregarded because (1) no evidence was provided to support that no other states require COS ratemaking by statute; (2) the "claim that Michigan is unique in mandating cost-of-service ratemaking is rebutted by preeminent authorities on public utility regulation – including Bonbright and the NARUC [National Association of Regulatory Utility Commissioners] Manual;" and (3) even if such claim were supported, ABATE "never explains why it makes a material difference whether cost-of-service ratemaking is memorialized in legislation when cost-of-service ratemaking is nonetheless universally followed by public utility commissions." MEC/NRDC/SC's replies to exceptions, p. 54 (footnotes omitted). MEC/NRDC/SC state:

> Mr. Dauphinais never even acknowledges the ubiquity of cost-of-service ratemaking when he characterizes Michigan as unique – rendering his testimony misleading. Therefore, Mr. Dauphinais' argument that DTE's unusually high residential rates relative to industrial rates can be explained by Michigan's adoption of cost-of-service ratemaking should be rejected as unfounded and contrary to the weight of authority on the subject.

Id. MEC/NRDC/SC next argue that ABATE's criticism about their witness's benchmarking of residential and industrial rates "is not well-taken because primary rates include only a very small distribution component. So in a comparison across states of residential and industrial rates, the distribution component of the industrial rates cannot possibly cause a significant amount of variance because it is such a small component of industrial rates." *Id*., p. 55. And, as to ABATE's witness not believing that DTE Electric allocates too little cost based on energy and too much cost based on demand but rather the opposite to be true, MEC/NRDC/SC assert, while "hardly surprising, [this opinion] is also not probative of anything." *Id*. MEC/NRDC/SC thus contend that ABATE's exception on this issue should be denied and that the ALJ's recommendation should be upheld.

The Commission agrees with MEC/NRDC/SC and the ALJ and finds that DTE Electric's production cost allocation should be revisited in the company's next rate case, which the

Commission anticipates may be filed in the very near future. Given the allocation of costs trend since Case No. U-17689, set forth in Exhibit MEC-5, along with the trendline illustrated in testimony on behalf of MEC/NRDC/SC and MEIBC/IEI (6 Tr 2188), the Commission finds it reasonable to revisit this issue to ensure that rates are cost-based, as required by MCL 460.11(1). For purposes of DTE Electric's next rate case, however, the Commission reminds future parties of the standard:

> that any party proposing to revise the production cost allocation method in a future case include in its evidentiary presentation an analysis using the equivalent peaker method or an approximation for comparison purposes. On pages 52-53 of the NARUC Manual, it states that "[e]quivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added."

January 31, 2017 order in Case No. U-18014, p. 100 (alteration in original).

IX. <u>RATE DESIGN AND TARIFFS</u>

A. Capacity Cost Calculation

DTE Electric proposed calculating the capacity charge in this case based on the approved method from Case No. U-18255 but with, as originally proposed by the company in Case Nos. U-18248 and U-18255, deduction of net energy sales net of fuel costs, amounting to $40.337 million in this case. 3 Tr 290-293; 7 Tr 3221-3222; Exhibits A-16, Schedule F1.5, and A-29, Schedule S3.

The ALJ agreed with the Staff, ABATE, Energy Michigan, and Kroger that the Commission has determined (in Case Nos. U-18248 and U-18255) that the offset to capacity costs under Section 6w of Act 341 is based on gross energy sales net of fuel costs, not the "net net method" employed by DTE Electric in its filing. PFD, p. 232. The ALJ additionally agreed with the Staff that DTE Electric inappropriately subtracted MISO Schedule 17 administrative service costs from energy sales in its capacity charge calculation. PFD, p. 232; 8 Tr 4272. The ALJ therefore recommended that the Staff's capacity calculation and charges in Exhibit S-6, Schedule F1.4, be adopted. Furthermore, the ALJ rejected Kroger's and DTE Electric's respective requests to update the capacity charge using costs and revenues determined in the Commission's final order in this case and for the new capacity charge to be reviewed by December 1, 2018, and implemented on January 1, 2019. The ALJ pointed out that the Commission has already completed the required 2018 review in Case No. U-18255 (8 Tr 4273) and further stated, "Although Kroger contends it has performed the required calculations to arrive at an updated capacity cost, its inputs were not particularly well examined by the parties." PFD, p. 233. The ALJ thus found the Staff's approach to recalculating and updating the capacity charge, by requiring DTE Electric to file updated amounts in its next general rate case application, to be reasonable and recommended that it be adopted. PFD, p. 233.

DTE Electric disagrees with the ALJ's recommendation that the Commission should maintain the capacity cost allocation method used in Case Nos. U-18248[23] and U-18255. Citing testimony on its behalf, the company avers that its "calculation of $40.3 million of energy sales net of fuel is consistent with PA 341 Section 6w(3)(B) and results in Electric Choice customers paying the same full embedded cost of DTE Electric's electric generation fleet as bundled customers" and should therefore be adopted. DTE Electric's exceptions, p. 98. With regard to the ALJ's recommendation to adopt the Staff's approach to recalculate and update the capacity charge, which DTE Electric contends "appears to contemplate that the final order in this case would produce a capacity charge incorporating updated costs from this case," the company notes that "generally,

[23] DTE Electric states, "The November 21, 2017 Order in Case No. U-18248 (the Company's capacity charge case) approved the Company's method, but adjusted for Gross Energy Sales net of fuel, and not the Company's recommended Net Energy Sales net of fuel costs." DTE Electric's exceptions, p. 97 (footnote omitted).

any base rate or PSCR factor change will change the capacity charge rates." *Id*. The company further asserts that a capacity charge review must be conducted by December 1 of each year pursuant to MCL 460.6w(3) and, in this regard, proposes that such rates established from this review become effective on January 1 of the following year.

In exceptions, the Staff agrees with the ALJ's decision but contends that its related recommendation was not addressed. More specifically, the Staff states:

> [T]he [ALJ] did not address Staff's related recommendation that the Commission order the Company to file updated revenue from gross energy market sales net of fuel in its next rate case using the same models used in the Commission-approved method in cases U-18248 and U-18255. Staff's initial brief pp 126-127; 8 TR 4271, 4273. The Company's reluctance to accept the Commission's ruling that MCL 460.6w(3)(b) means all energy market sales, not merely "excess" sales into the market, has prevented the parties in the instant case from updating the capacity charge with the most up-to-date data. To avoid this in the future, the Company should be ordered to file the appropriate update of capacity costs described above, consistent with the Commission's previous decisions.

Staff's exceptions, p. 9. The Staff also notes the correct witness whose testimony was referenced on its behalf on pages 249-250 of the PFD.

Kroger agrees with the ALJ's recommended method for calculating the state reliability mechanism (SRM) capacity charge but disagrees with the ALJ's recommended rejection of using the costs and revenues approved in this case to do so. Kroger believes that the ALJ's rationale "is a misapplication of [its] argument and not a reason to deny [its] proposal." Kroger's exceptions, p. 2. Kroger asserts that there is no reason to not update the SRM capacity charge to reflect current rates, as current rates should be used whenever possible in determining charges to be applied to customers' bills.

In replies to exceptions, DTE Electric states that "[t]he exceptions are puzzling because they agree with the [ALJ] and the [ALJ]'s recommendation already appears (at least to the Company) to contemplate that the final order in this case would produce a capacity charge incorporating updated costs from this case." DTE Electric's replies to exceptions, p. 46.

In its reply, the Staff contends that the ALJ properly found that revenue from gross energy sales should be used in calculating the capacity charge. The Staff argues that DTE Electric's statement about its calculation of $40.3 million being consistent with Section 6w(3)(B) of Act 341 "completely ignores that the Commission has specifically ruled otherwise." Staff's replies to exceptions, p. 38.

The Staff also contends that Kroger's exceptions on this issue should be rejected. According to the Staff, Kroger's method of calculating gross energy sales does not adhere to the method approved in Case Nos. U-18248 and U-18255.

In its reply, Energy Michigan calls DTE Electric's assertion that the company's method for calculating the capacity charge was approved by the Commission in Case No. U-18248 "misleading at best." Energy Michigan's replies to exceptions, p. 2. Seeing no new arguments presented by DTE Electric in exceptions, and recalling the rejection of the company's method by the Commission in its November 21, 2017 order in Case No. U-18248 and in the 2018 orders, Energy Michigan agrees with the ALJ.

The Commission agrees with the Staff, Kroger, Energy Michigan, ABATE, and the ALJ. DTE Electric is directed to file updated gross energy sales and other inputs in its capacity cost calculation in its next rate case in accordance with the method advocated by the Staff in this case, that is, updated revenue from gross energy market sales net of fuel. DTE Electric has offered no new evidence or argument that persuades the Commission that MCL 460.6w(3)(b) did not encompass gross sales, and the Commission continues to reject DTE Electric's net net proposal for the same reasons articulated in Case No. U-18248. *See*, November 21, 2017 order in Case No. U-

18248, p. 66; 8 Tr 4271. Finding that the utility provided no convincing argument otherwise, the Commission also agrees with the Staff and the ALJ that MISO Schedule 17 administrative costs should not be subtracted from projected energy sales revenue. The Commission thus adopts the Staff's method as applied herein, and the Staff's proposed capacity revenue requirement, which has been adjusted based on the decisions in this order to $1.24 billion. While it is free, of course, to make any argument it wishes, in its next rate case filing DTE Electric shall provide an updated capacity cost calculation applying the method approved herein.

B. Customer Charges

1. Residential and Commercial Secondary Customer Charges

Asserting that all demand and customer-related distribution costs should be collected through the customer charge to better align rates with costs, DTE Electric proposed recovery of demand-related costs through this customer charge, for residential and small commercial customers. 7 Tr 3220-3221; Exhibit A-16, Schedule F1.4. Accordingly, for residential rate schedules not for supplemental electric service (D1, D1.2, D1.6, D1.8, and D2), DTE Electric proposed increasing the monthly service charge from $7.50 to $9.00 per customer in the interest of gradualism (and thus also increasing the RIA service provision of the D1 tariff to offset the D1 service charge (also $9.00 per customer per month) and the residential senior service (RSS) provision of the D1 tariff to offset half of the D1 service charge ($4.50 per customer per month)). 8 Tr 3868-3869; Exhibit A-16, Schedules F1.4 and F3, pp. 2-3. For commercial secondary rate schedules (D1.8, D3, D3.2, D3.3, D4, and R8), DTE Electric also proposed increasing the service charge, from $11.25 (or $13.67 for rate D4) to $15 per customer per month, also in the interest of gradualism. 5 Tr 1430-1432.

The ALJ agreed with the Staff's recommendation to retain the current customer charges for residential and commercial secondary customers. PFD, p. 235. The ALJ discussed DTE Electric's similar proposals in its last three rate cases, and the Commission's consistent rejection of the company's approach and adoption of the Staff's method and, in this regard, specifically stated, "DTE Electric should be mindful of its own admonition that parties should not be 'forced to respond repeatedly to arguments that have been conclusively resolved, as if the Commission's prior decisions are meaningless[.]'" PFD, p. 235 (alteration in original, footnote omitted).

DTE Electric takes exception to the ALJ's recommendation, maintains that its proposed cost-allocation methodology is appropriate, and notes that "much of the opposition was based on the faulty premise that there would be a residential rate increase." DTE Electric's exceptions, p. 100. However, according to the company:

> if the service charge does not increase, then the variable distribution rate must be higher than what is proposed so that the Company's distribution rates will recover the same amount of revenue. The Commission has previously recognized that such a fixed-charge increase "does not increase the residential class' cost of service. Rather, it merely reflects the fact that a flat customer charge, rather than an energy related charge, is a more appropriate way of collecting the fixed costs associated with serving each residential customer at any usage level[.]"

Id., citing 8 Tr 3869 and the June 10, 2008 order in Case No. U-15245, p. 74. In this regard, DTE Electric reiterates that most revenue collected from residential customers and commercial secondary customers would derive from usage (or variable charges) and also repeats its proposal to accordingly increase its RIA and RSS provisions in its D1 tariff to offset all or half of the proposed customer charge increase for its residential customers.

The Attorney General contends that the ALJ was correct in her analysis and recommendation on these charges and continues to advocate for the retention of the current customer charges for residential and commercial secondary customers. The Attorney General states that, in exceptions, DTE Electric merely rehashes arguments previously presented and, despite acknowledging criticism by the ALJ in her PFD, continues to argue that its proposed methodology is appropriate. The Attorney General recalls this same issue in the December 11, 2015 order in Case No. U-17767, pp. 119-120, and the April 2018 order, p. 65, and further repeats appropriate determinations made by the ALJ in this case, specifically referencing pages 234-235 of the PFD. The Attorney General concludes:

> Because DTE does not present any new argument in its exceptions and because the Commission has repeatedly rejected the Company's use of the methodology it proposes, the AG [Attorney General] recommends that the Commission follow the AG's and ALJ's recommendation and keep residential and small commercial customer charges at their current rates.

Attorney General's replies to exceptions, p. 35.

In replies to exceptions, the Staff contends that DTE Electric's discussion about opposition in its exceptions mischaracterizes the Staff's position. The Staff clarifies that its opposition to the company's customer charges "was based primarily on the Company's methodology, which differs from Staff's method and the method that has been repeatedly approved by the Commission (Staff's Initial Brief, p 121-124)." Staff's replies to exceptions, pp. 40-41. Contrary to DTE Electric's arguments otherwise, the Staff argues that demand-related costs are not fixed, but rather vary with demand, which is reflected in the Staff's method.

MEC/NRDC/SC contend that the ALJ correctly recommended that the Commission reject DTE Electric's proposed residential and secondary customer charge increases. MEC/NRDC/SC discuss prior Commission decisions on this issue, specifically Case Nos. U-17767, U-18014, and U-18255 rejecting the company's request to increase its fixed monthly service charge for residential customers. MEC/NRDC/SC argue that DTE Electric's theory in this case ("that in the absence of a residential demand charge, all distribution costs in the COSS should be included in the service charge") is the same as that advanced by the company in Case No. U-18255. MEC/NRDC/SC's replies to exceptions, p. 58. In response to the company's arguments in exceptions that it could have proposed higher monthly service charges but did not in the interest of gradualism, MEC/NRDC/SC assert that "the problem with this argument is that DTE could not have *validly* proposed higher monthly service charges because the methodology on which those proposals would have been based has been discredited based on the three Commission orders described above." *Id.*, p. 59. As to the company's review of its methodology and how NARUC classifies all distribution plant as demand-related, customer-related, or both, MEC/NRDC/SC note the Commission's rejection of the company's argument about this three times now. MEC/NRDC/SC further argue that the company's point that service charges on a residential bill are relatively small in comparison to charges that are dependent on usage is "immaterial," as rates are required to be based on COS, and "[i]f DTE's proposed charge is based on a methodology that has been rejected for cost of service purposes, there is no need to evaluate its rate impact." *Id.*, pp. 60-61.

The Commission agrees with the Staff, the Attorney General, MEC/NRDC/SC, and the ALJ and maintains that this monthly customer charge for residential and commercial secondary customers should only recoup those costs directly linked to the customer's mere existence (i.e., costs to connect the customer to the system). *See*, May 10, 1976 order in Case No. U-4771 (Attachment A, p. 2); January 18, 1974 order in Case No. U-4331, p. 30; December 11, 2015 order in Case No. U-17767, pp. 119-120; January 31, 2017 order in Case No. U-18014, pp. 110-111; and April 2018 order, p. 65.

2. Primary Voltage Customer Charge

Arguing that the current $275 primary monthly service charge has not been shown to be cost-based in the company's past three rate cases, Kroger recommended that DTE Electric be ordered to design a cost-based primary monthly customer charge, developed using the previously-approved methodology regarding which costs should be included in the customer charge. Alternatively, Kroger recommended that DTE Electric be ordered to use the company's customer cost analysis from its last rate case (Case No. U-18255), representing a primary monthly customer charge of $53.52 per month. 7 Tr 2709-2718; Exhibit KRO-3.

The ALJ agreed with Kroger and recommended that the COS-based calculation from Case No. U-18255 (a primary monthly customer charge of $53.52 per month) be adopted. PFD, p. 237. Alternatively, the ALJ recommended that, if not in this case, DTE Electric be directed to, in its next rate case, calculate its primary monthly customer charge consistent with the method used for residential and commercial secondary customers.

DTE Electric disagrees with the ALJ's recommendation, asserting no basis for such recommendation, and asserts that its primary monthly charge of $275 should be maintained. DTE Electric takes exception to Kroger's proposal relying on the record from Case No. U-18255, rather than the record in this case, calling such proposal essentially an untimely rehearing request in that case. The company also raises *res judicata* and collateral estoppel to assert that Kroger did not offer anything not already considered by the Commission.

In exceptions, the Staff asserts that, regardless of the decision on the company's primary monthly customer charge, the Commission should follow standard rate design procedures and that the ALJ erred in failing to specify that in her PFD. As the Staff explains:

> The final Commission approved revenue requirement must be flowed through the cost of service study so that the Commission approved allocation methodologies are

> applied to each rate class. The results of the cost of service study are then used to guide rate design in providing the appropriate price signals that match the manner in which costs are caused. This is not the same as simply adjusting every rate component by an equal percentage as proposed by Kroger witness Bieber. This will result in worse price signals because certain costs that are appropriately collected using one rate component will not be collected in a manner consistent with their allocation and will end up in another component. Kroger's rate design proposal, as related to any change in the primary voltage customer charge, should be rejected for the simple reason that it does not send proper price signals.

Staff's exceptions, p. 8.

Kroger notes agreement with the ALJ's primary recommendation but argues that the ALJ's alternative recommendation "would require smaller Primary customers to continue to subsidize large Primary customers for an indefinite period of time." Kroger's exceptions, p. 3. Kroger reiterates:

> DTE's current and proposed service charge for Primary customers is over 5 times greater than customer costs using the cost-based method used for Residential and Commercial-Secondary customers for calculating customer-related costs. As a result, DTE is over-recovering customer-related costs through service charges for Primary customers. Proper alignment of customer costs with the Primary service charge is important for ensuring equity among customers, because properly aligning charges with costs minimizes cross-subsidies among customers. When the service charge is set significantly above customer-related costs, smaller customers on the rate schedule are over-charged and thereby subsidize the larger customers on the rate schedule. Aligning rate design with underlying cost causation also improves efficiency because it sends proper price signals.

Kroger's exceptions, pp. 3-4 (footnote omitted). Kroger thus asserts that the Commission should end this intra-class subsidy in this case.

In replies to exceptions, DTE Electric maintains its disagreement with the ALJ's recommendations. The company also states that the Staff, in exceptions, raises a valid point about the need for an offsetting rate adjustment if the monthly service charge for primary customers were reduced. DTE Electric asserts that "[i]t is inappropriate for Kroger to advocate (and the [ALJ] to implicitly suggest) an allegedly 'cost-based service charge' without recognizing that the service charge is just one component of rates, and that overall rates must be 'equal to the cost of providing service to each customer class.'" DTE Electric's replies to exceptions, p. 47, citing MCL 460.11(1). The company thus avers that the $275 monthly service charge for primary customers should be continued and that there is no need to revisit this charge in its next rate case.

Kroger reasserts that DTE Electric admitted and confirmed that it did not perform any analysis to determine if its proposed primary customer charge in this case was cost-based—rather, according to Kroger, DTE Electric just relied on the 2018 orders and then did not propose changing the existing $275 primary monthly customer charge in this case. Kroger also argues that DTE Electric's *res judicata* and collateral estoppel claims are inapplicable here, noting that Kroger is not proposing to change the approved method for determining customer charges, just that it also be used to determine primary customer charges; and that these legal principles, as DTE Electric concedes, do not apply to the Commission's ratemaking decisions. Kroger's replies to exceptions, pp. 4-5. Kroger indicates no opposition to the Staff's proposed alternative to flow the final revenue requirement through the COSS, if the Commission adopts the ALJ's recommendation on the primary customer charge. 7 Tr 2719. Kroger additionally highlights the Staff's non-opposition to Kroger's rate design proposal regarding the methodology used to determine the costs to be included in the primary customer charge in this case ($53.52 per month).

The Commission agrees with Kroger and the ALJ's primary recommendation, along with the Staff's recommendation to flow the final revenue requirement through the COSS to ensure standard rate design procedures are followed in this case. Considering the costs that should be included in monthly customer charges, as discussed above in Part IX, Section B.1., and the customer-related costs for primary customers demonstrated in Exhibit KRO-3, the Commission finds it reasonable to require DTE Electric to set this monthly customer charge for primary customers at $53.52 per month based on the evidence presented in this case.

C. Fixed Bill and Weekend Flex Pilot Proposals

For new ways for residential customers to pay for their electricity, DTE Electric proposed a Fixed Bill pilot and a Weekend Flex pilot. For the Fixed Bill pilot, DTE Electric proposed a pilot program for up to 5,000 eligible residential customers who would pay a fixed monthly amount not subject to any adjustments for actual usage for a period of one year. 6 Tr 2097-2104. And, for the Weekend Flex pilot, DTE Electric proposed a pilot for up to 5,000 eligible residential customers, where the eligible residential customers in this pilot program would pay the standard residential service D1 rate for weekday usage and a fixed monthly charge for weekend usage (12:00 a.m. on Saturday to 11:59 p.m. on Sunday). 6 Tr 2088-2096; Exhibit A-16, Schedules F8.

The ALJ recommended that DTE Electric's proposed Fixed Bill pilot program be rejected "on grounds that, more likely than not, the effects of the program would be contrary to the energy conservation policy goals of the State of Michigan and the company's energy efficiency efforts." PFD, p. 246. Here, the ALJ also discussed a similar program proposed by the company in 2012 and the similar concerns raised by the Commission in its December 20, 2012 order in Case No. U-17054 (December 20 order). The ALJ further elaborated:

> The concerns about the effects on energy efficiency efforts remain, and they are particularly salient considering the expanded energy savings requirements under Act 342, not to mention the company's efforts to reduce on-peak usage through various DR programs. In addition, Mr. Jester and Mr. Coppola raise a valid point, namely that the Fixed Bill program does not appear to provide much more benefit to customers than the company's BudgetWise Billing program, which could perhaps be improved by implementing the same type of usage alerts, as proposed for the Fixed Bill program, that would warn customers about potentially higher budget bill amounts in the future.

PFD, p. 247.

As to DTE Electric's proposed Weekend Flex pilot program, the ALJ, albeit finding this recommendation to be a "closer call," nevertheless recommended that it also be rejected but "on grounds that it is largely duplicative of the company's current TOU [time-of-use] rate programs, which, as the Attorney General points out, could be modified to provide a larger discount for weekend usage." PFD, p. 247. The ALJ also discussed the complexity of the program and possible resulting customer confusion. If the Commission were to approve either pilot, however, the ALJ agreed with the Staff (8 Tr 4299) and opined that, "although removing participants from the program for excessive usage is appropriate, charging a penalty is not." PFD, p. 248.

DTE Electric disagrees that its pilots should be rejected. With its Fixed Bill pilot program, the company reiterates the intent and impetus behind the proposal and the success of other U.S. utilities who offer such a program and asserts:

> While EWR [energy waste reduction] is an important consideration, it is not the only consideration when designing a product or service that addresses customer requirements and the Company has carefully designed EWR elements into the program. Customer preferences in this case should be provided an equal, if not greater consideration in supporting this pilot. Even so, the [ALJ]'s concerns regarding EWR impacts are speculative at this point as it is premature to assume any result until the pilots are conducted and results can be analyzed.

DTE Electric's exceptions, p. 104. Recalling testimony, the company re-explains price signals through usage alerts and the reasonable usage clause for the Fixed Bill pilot program, which DTE Electric asserts will address inefficient use of electricity and ensure price signals are reinforced, not diluted. DTE Electric further disputes reliance on the December 20 order, arguing that its proposed program in this case differs from that proposed in 2012 in that this case is part of a contested proceeding and the program excludes components that were of concern back in 2012. The company further emphasizes the strong support of its proposed pilots based on, in part, an

April 2018 survey of residential customers and negates the perceived duplicative nature of its Fixed Bill pilot as compared to its BudgetWise Billing program:

> Mr. Clinton explained that the Fixed Bill pilot would provide absolute bill certainty for each 12-month term instead of the quarterly adjustments and annual settlement that may be required under the Company's existing equal monthly billing (BudgetWise Billing). The April 2018 survey also indicated that the majority (55%) of the customers interested in the Fixed Bill option would likely come from current BudgetWise Billing customers. This also shows that there is strong demand for an offering that provides greater consistency in monthly energy spending beyond what BudgetWise Billing affords (6T 2116, 2119-20, 2123).

DTE Electric's exceptions, p. 106.

The company likewise disagrees with the ALJ's recommendation as to its Weekend Flex pilot, specifically disagreeing with the ALJ's reasoning that its TOU rates could be modified instead. DTE Electric states:

> Mr. Clinton explained that the Company's existing TOU rates already incentivize customers to shift usage to the weekend by providing a significantly lower rate during the weekends. DTE Electric also already has variable rate structured time-of-use electric pricing options. These pricing options resonate with certain customers, but the Weekend Flex pilot is unique because it would offer a time-of-use electric pricing option with a fixed component for usage. This fixed-component is a key element that may resonate with certain customers who have otherwise declined DTE Electric's current options. Thus, by offering the Weekend Flex provision, there is the potential for greater overall voluntary enrollment in time-of-use rates (6T 2117-18).

DTE Electric's exceptions, p. 107. Also disagreeing with the notion of alleged customer confusion, DTE Electric recalls testimony that Weekend Flex would not be much different from TOU rates D1.8 or D1.2. The company concludes that it listened to its customers, studied desirability, and structured its proposed pilots in a way to increase customer satisfaction, improve affordability, and shift usage to low load periods. As a compromise, however, DTE Electric states:

> If the [ALJ's] and Staff's speculation on the outcome of the pilots turns out to be correct (i. e. increased usage by customers), then the Company would take that into

> consideration when determining whether to seek approval of these programs on a permanent basis. However, without running the pilot there is no data on which to base these conclusions.

DTE Electric's exceptions, p. 108.

In replies to exceptions, the Staff contends that the ALJ did not err in her recommendations. Regarding speculation, price signals, and customer interest, the Staff recalls its prior responses to DTE Electric on these claims. Staff's replies to exceptions, pp. 33-34, referencing Staff's initial brief, pp. 150-152. And, as to the company's arguments that its Fixed Bill pilot program differs from that proposed in 2012 and as such the December 20 order is not relevant, the Staff asserts that "this does not obviate the concern expressed by the Commission [in that order], as stated and quoted in the PFD." Staff's replies to exceptions, p. 33, referencing PFD, pp. 246-247.

The Attorney General also contends that the ALJ was correct in her analysis and recommendations and expresses her continued opposition to these two pilot programs. The Attorney General insists that, contrary to the company's assertions, "energy conservation is an important policy goal in Michigan and that the Commission should reject programs that so clearly dissuade any type of conservation." Attorney General's replies to exceptions, p. 36. The Attorney General additionally points out the speculative and duplicative nature of these programs, specifically recalling DTE Electric's own exceptions where the company acknowledges the wide range of TOU options it already offers. The Attorney General repeats continued concern over the complexity of these programs, specifically the Weekend Flex program, and overlap with the company's BudgetWise Billing program, which the Attorney General avers will lead to significant customer confusion.

MEC/NRDC/SC contend that the ALJ properly rejected DTE Electric's proposed pilot programs and that the Commission should uphold such rejection. MEC/NRDC/SC highlight, as outlined in the PFD, arguments raised by them, the Staff, and the Attorney General. MEC/NRDC/SC reiterate that the pilots are not designed to send price signals to incentivize reduced usage and that fixed bills, by definition, "do not reflect actual pricing at the time of use." MEC/NRDC/SC's replies to exceptions, p. 62. As to the company's argument that the programs do send price signals, MEC/NRDC/SC aver that "it appears the alerts would be based on aggregate usage during a period (*e.g.*, month), rather than based on usage at particular times," and "[t]hus, the usage alert does not correlate to Company costs." *Id*. MEC/NRDC/SC further argue that DTE Electric's ability to unilaterally remove customers who overconsume eliminates the opportunity to modify customer behavior. MEC/NRDC/SC also discuss the programs' failure to reward underconsumption for efficiency measures and behavior modifications, particularly those customers that enroll in the Fixed Bill program and who, despite taking efficiency measures early in the program, "may not see any benefit until the following 12-month period, assuming they stay in the program and rates do not increase." *Id*., pp. 62-63. Finally, if the Commission were to approve these pilots, MEC/NRDC/SC urge the Commission to "modify both programs to remove the over-usage penalty, as recommended by the ALJ." *Id*., citing PFD, p. 248.

The Commission agrees with the Staff, the Attorney General, MEC/NRDC/SC, and the ALJ and finds that DTE Electric's proposed Fixed Bill and Weekend Flex pilot programs should be rejected. Given the valid concerns raised by the Staff, the Attorney General, and MEC/NRDC/SC; the various rate options already available to customers; and the forthcoming roll-out of the new summer on-peak rate, as further discussed below, the Commission does not find either of the company's proposed pilot programs to be reasonable or prudent at this time.

D. Rate D8 and D11

DTE Electric proposed changes to the determination of voltage level energy discounts and voltage level demand adjustments for its D8 and D11 rates.[24] 5 Tr 1218, 1223-1225; Exhibit A-16, Schedule F12.

Agreeing with the Staff and ABATE, the ALJ recommended that DTE Electric's method for calculating voltage level demand discounts be rejected. PFD, p. 251. The ALJ quoted the Commission's determination in the April 2018 order, p. 69, and further stated:

> DTE Electric has not shown that its method is cost-based; in fact ABATE's evidence, that under the company's method the discounts for sub-transmission level are greater than those for transmission level, appears to demonstrate the opposite. Accordingly, this PFD recommends that the Commission again approve the Staff's method for calculating demand and energy voltage level discounts.

PFD, p. 252.

In exceptions, DTE Electric contends that its voltage level discounts and voltage level demand adjustments are cost-based in accordance with MCL 460.11. The company further contends that the ALJ's reasoning, with regard to its proposed method of determining energy-based voltage level discounts, focuses on demand-based voltage level discounts and is flawed. DTE Electric states:

> Mr. Bloch explained that the Company's proposed method of determining energy-based voltage level discounts allocates energy costs to each voltage level based on loss adjusted sales. Voltage level energy costs are then divided by the corresponding voltage level billed sales to determine the voltage level energy rate from which voltage level discounts are determined. Calculating energy voltage level discounts based on loss adjusted sales at each voltage level better aligns costs with cost causation compared to the method approved in Case No. U-18255 that calculates these discounts by multiplying voltage level loss factors by the class average energy rates.

[24] "Rate Schedule D11 is the Company's main primary rate schedule and is available to customers served at primary, sub-transmission or transmission voltage. . . . Rate Schedule D8 is the Company's primary voltage interruptible rate which is limited to 300 megawatts." 5 Tr 1221.

DTE Electric's exceptions, pp. 109-110. For its demand-based voltage level discounts, the company argues that the approved method from Case No. U-18255 "only considers loss differences between voltage levels and does not consider the voltage level cost responsibility to which the losses are applied." *Id.*, p. 110. Here, DTE Electric contends that the Commission's direction to determine voltage differentiated power supply demand charges "should be interpreted to mean voltage level demand charges that are consistent with cost-based principles . . . ," which the company claims its proposed voltage level demand rates are, "using the same voltage level cost responsibilities that would result by performing a separate power supply voltage level COSS for each rate (5T 1225)." DTE Electric's exceptions, p. 110. Contrary to the ALJ's reasoning on page 252 of the PFD, DTE Electric argues that:

> To determine demand voltage level discounts without accounting for voltage level cost differences, which are known, does not follow cost of service principles. . . . Voltage level cost differences are equally relevant to setting voltage level demand discounts as are loss factors and can have a more significant impact than loss factors on demand voltage level discounts. To not recognize the voltage level cost differences based on the 4CP demand would be in stark contrast to how the Company allocates all of its other power supply related capacity costs.

DTE Electric's exceptions, p. 111. The company further asserts that the ALJ neglected to analyze the testimony of ABATE's witness during cross-examination. *Id.*, pp. 12-13, referencing 7 Tr 2879, 2880, 2882, 2885, 2886, and 2889-2891. DTE Electric avers that its proposal in determining demand voltage level discounts is the only one that follows COS principles by including loss factors and capacity cost, and reduces intra-class subsidies. Thus, according to the company, the Commission should adopt its proposed changes to the determination of voltage level energy discounts and voltage level demand adjustments for its D8 and D11 rates, along with its proposal to add voltage level demand adjustments to its D6.2 billing demand charge.

In replies to exceptions, the Staff contends that DTE Electric's exception erroneously "implies that the Staff method, approved by the Commission in the previous 3 rate cases, is not in compliance with MCL 460.11." Staff's replies to exceptions, p. 39. Averring that the currently approved method does comply with the law, the Staff states that "the existence of voltage level discounts as opposed to separate rates shows that customers on each applicable rate are currently treated as one class by the Company, as opposed to separate classes. Each voltage level within rates D8 and D11 is not its own rate class." *Id*. Given no new arguments presented by the company, and approval of the Staff's method three times before, the Staff avers that the Commission should approve the ALJ's recommendation.

In reply, ABATE expresses support for the ALJ's recommendation as well, and asserts that DTE Electric has not met its burden of proof to revisit and change the current methodology. ABATE avers that the company's "very complex methodology" is "counter intuitive and illogical" and should be rejected. ABATE's replies to exceptions, pp. 3-4.

The Commission agrees with the Staff and the ALJ and finds that DTE Electric's proposed changes to the determination of voltage level energy discounts and voltage level demand adjustments for its D8 and D11 rates should be rejected. The Staff calculated the power supply demand and energy voltage level discounts for these rate schedules in accordance with the method approved by the Commission, which requires that the voltage level loss factor differentials for demand and energy be applied directly to the proposed demand and energy charges to produce the discounts. *See,* December 11, 2015 order in Case No. U-17767, p. 122; January 31, 2017 order in Case No. U-18014, p. 114; April 2018 order, p. 69; and 8 Tr 4286. The Commission finds this method is superior to DTE Electric's proposal, which, for the energy discount, treats Rates D8 and

D11 as one class, and for the demand voltage level discount relies on contributions to the 4CP. 5 Tr 1224-1225. The Commission adopts the findings and recommendations of the ALJ.

E. Rider 3 Stand-By Service[25]

1. Allocation of Power Supply Cost to Rider 3

DTE Electric proposed allocating the power supply capacity costs to Rider 3 (R3) using 4NCP[26] to account for R3 customers' abnormal demand variability and to eliminate the associated subsidy provided to these customers by D11 customers. 5 Tr 1232-1236.

Persuaded by the recommendation made by the Staff, ABATE, and MEIBC/IEI, the ALJ recommended that the power supply cost allocation method approved in Case No. U-18255 be retained. PFD, p. 255.

In exceptions, DTE Electric maintains that "4CP does not provide an appropriate basis to determine sub-allocating power supply cost to the R3 class, and averaging as ABATE proposed, only masks the resulting subsidization problem." DTE Electric's exceptions, p. 115; 5 Tr 1234. DTE Electric argues, "The currently approved method of averaging 4CPs over several years does not address this variability (its [sic] merely a mathematical average having no meaningful connection to the demands placed upon DTE Electric generation to serve these few customers) and results in D11 customers subsidizing R3 customers (5T 1220, 1233-36)." DTE Electric's exceptions, p. 116. The company asserts that it provided ample and compelling evidence to demonstrate that actual 4CP demand is not an appropriate method for allocating capacity costs to R3. DTE Electric, however, negates any notion that 4CP is a poor allocator for D11 customers,

[25] "The Company's Rider 3 rate provides standby service for various customers with generation facilities operating in parallel with the Company's system." 5 Tr 1221.

[26] "4NCP is the average of the 4 class peak hour loads during hours 15, 16, 17 and 18 for June, July, August and September for each class." DTE Electric's initial brief, p. 134, n. 82.

pointing to the appropriateness of this allocator, being in line with all other COS classes, as demonstrated in its illustrative tables. The company further disputes MEIBC/IEI's assertions by stating that "MEIBC/IEI provided no supporting evidence . . . and their witness confirmed that she has never performed a cost of service study (5T 1251; 8T 3490- 3491). Thus, there is no proper evidentiary basis to rely on [M]EIBC/IEI's opinion concerning Rider 3 cost allocation." DTE Electric's exceptions, p. 117. The company additionally recalls rebuttal testimony addressing ABATE's arguments (*see*, 5 Tr 1248-1250) and argues ABATE's position appears to be based on a misunderstanding of data shown in one of the company's tables. DTE Electric's exceptions, pp. 117-118.

In replies to exceptions, the Staff recalls testimony from one of its witnesses refuting DTE Electric's claims (8 Tr 4242-4243), asserts that the company merely restates arguments previously raised, and maintains that the ALJ correctly found that the production allocator for R3 should be consistent with the method approved in the 2018 orders. Staff's replies to exceptions, p. 42.

MEIBC/IEI assert that the Commission should adopt the ALJ's recommendation to retain the power supply cost allocation method approved in the 2018 orders. MEIBC/IEI recall testimony from one of their witnesses (8 Tr 3475) and combats DTE Electric's exceptions by stating NCP, unlike 4CP, bears no clear relation to system peaks, which are what drive the need for company investments in capacity. MEIBC/IEI further suggest that DTE Electric fails to explain why a COSS should be necessary to determine whether NCP or 4CP bears a better relation to system peaks. MEIBC/IEI's replies to exceptions, p. 3.

ABATE, in addressing DTE Electric's "misunderstanding of data" claim against ABATE, states that ABATE's witness addressed this claim both in direct testimony and on cross-examination; however, according to ABATE, "a careful examination of the record shows that his testimony ultimately does not depend on whether or not the values in the column in question of Mr. Bloch's Table 2 are as DTE says or are as Mr. Dauphinais says." ABATE's replies to exceptions, p. 4. *See also*, *id.*, pp. 4-6. ABATE thus recommends that the Commission reject DTE Electric's exceptions and continue the current, recently approved methodology for allocating costs to the R3 customer class.

The Commission agrees with the Staff, MEIBC/IEI, ABATE, and the ALJ and finds that the current method for allocating power supply capacity costs to R3 customers should be retained. The impetus for DTE Electric's proposed change is based on a review of R3 load by itself; however, R3 is not a separate class but is rather within D11, and, as recognized by the Staff, "Any smaller group of customers is going to show more variance than the entire class." 8 Tr 4243. The Commission adopts the findings and recommendations of the ALJ.

2. Generation Reservation Fee

For R3, DTE Electric also proposed changing the basis for setting the generation reservation fee that was approved in Case No. U-18255, by removing the requirement to set the fee based on generator availability and allowing changes in the R3 capacity revenue requirement to be collected through this fee. 5 Tr 1232, 1237-1239.

Congruent with her decision above, the ALJ likewise recommended that the method for determining the generation reservation fee for R3 (from Case No. U-18255) be retained. In her rationale, the ALJ discussed the Staff's point that this method is consistent with the Staff's Standby Rates Workgroup Report and also mentioned the limited experience DTE Electric has had with the changes to R3 since Case No. U-18255. PFD, p. 258.

In exceptions, DTE Electric recalls the Commission's adoption of ABATE's proposal to set the generation reservation fee based on the best performing generators of R3 customers but also recalls its argument that the Commission "did not specifically address the Company's concerns that availability is not an appropriate basis to set the generation reservation fee since availability does not reflect generator performance and the Company's need to reserve capacity." DTE Electric's exceptions, pp. 119-120. The company reasserts the fundamentally flawed nature of ABATE's proposal and highlights that no party promoting this position provided any supporting evidence to show a link between generator availability and generator performance. The company further discusses the R3 rate design constraints (i.e., all R3 demand charges based on the D11 billing demand) and claims that this "limits the ability to design R3 capacity rates equal to R3 costs, which are not determined based on the D11 billing demand." *Id.*, p. 121. DTE Electric thus maintains its request to remove the requirement to set the generation reservation fee based on generator availability and allow changes in the R3 capacity revenue requirement to be collected through this fee.

Consistent with their assertions above regarding the allocation of power supply costs to R3, MEIBC/IEI likewise contend that the Commission should adopt the ALJ's recommendation to retain the method for setting the generation reservation fee approved in the 2018 orders.

ABATE recommends that the Commission reject DTE Electric's exceptions advocating for a much higher monthly reservation charge and adopt the ALJ's recommendation to continue with the currently approved methodology for allocating costs to the R3 customer class. ABATE reiterates:

> [T]he monthly reservation charge is essentially a minimum required contribution toward fixed power supply costs that must be paid regardless . . . of the amount of standby service taken by the customer (6 T 1752-1753). As such, the monthly reservation charge is properly based on the estimated best equivalent forced outage rate operating characteristic of the facilities needing standby service.

ABATE's replies to exceptions, p. 8.

The Commission agrees with the Staff, MEIBC/IEI, ABATE, and the ALJ and finds that DTE Electric's proposal should be rejected. The Commission agrees that the company's proposal fails to recognize that the generation reservation fee is not related to actual use of R3 standby service but rather reflects a minimum required contribution toward fixed power supply costs.

F. Rate D1 Summer On-Peak Charges

In the 2018 orders, the Commission directed DTE Electric, in its next general rate case, to file tariffs reflecting the elimination of the summer monthly block rate and its replacement with a summer on-peak/off-peak rate, and a proposal for allowing customers who opt out of AMI to retain the existing rate structure. On rehearing, the Commission recognized this as being a significant change and clarified that this decision did not foreclose consideration of implementation issues concerning timing or costs in a future rate case. In this current rate case, the company made the required filing, proposing a rate structure and an implementation plan, with associated costs.

Notwithstanding the company's compliance with the 2018 orders, DTE Electric maintained the position it took in that docket (Case No. U-18255) and requested that the Commission reverse its prior directive. 3 Tr 85. In this regard, DTE Electric requested that the Commission (1) allow the company to retain its existing Rate D1 pricing schedule, as opposed to requiring DTE Electric to convert the non-capacity charge of its default residential rate to a TOU rate structure (i.e., summer on-peak rate), and (2) allow customers to retain the ability to voluntarily opt into various TOU rate products the company currently has available. *Id.*, pp. 83-85. If the Commission does not reverse its prior directive, however, DTE Electric claimed that it must be permitted to move forward with implementing this new, Commission-ordered Rate D1 pricing schedule over a reasonable time period and with all implementation costs being recoverable. 3 Tr 85.

Through her discussion of the issues, the ALJ implicitly declined to reverse the rulings in the 2018 orders directing DTE Electric to propose these new rates. PFD, pp. 258-266.

In exceptions, DTE Electric maintains its position that the Commission should reverse its prior ruling.

In replies to exceptions, the Attorney General supports the company's request. The Attorney General reiterates:

> Again, the AG's concern is that if the Commission does not reverse its prior ruling, the switch to the TOU rate design will create considerable hardship on residential customers, particularly senior citizens living on fixed income and small businesses. Customers who want to be billed based on time-of-day usage have that option in the rate schedule offerings that the Company provides. Customers should not be forced into such a rate scheme that would drastically change their monthly bills.

Attorney General's replies to exceptions, p. 38 (footnote omitted).

The Staff disagrees with DTE Electric. The Staff states, "Given the low opt-in rates for the Company's other offerings, and the difference in the way those rates are structured, they do little to nothing to reduce intra-class subsidization and should therefore not be considered true alternatives to the summer on-peak rate." Staff's replies to exceptions, p. 34. However, if the Commission shares the company's lack of choice concerns, the Staff avers that an opt-in structure is not the answer. Rather, although not currently recommending approval of such a structure, the Staff states that an opt-out structure would relieve these concerns and retain the majority of the benefits of a summer on-peak rate. The Staff further states:

> In addition, the Company's claims regarding potential customer reluctance have not yet been shown to be true. Luckily, as noted by the Company in other contexts, a significant amount of data will be collected through the pilot which can be used to inform such decisions. Staff recommends that any decisions related to changing the default structure to an opt-out structure wait until this data is available, but in no case should an opt-in structure be approved. As the Company presented no new evidence related to approval of the summer on-peak rate, the [ALJ] properly recommended its continued approval.

Staff's replies to exceptions, p. 35.

MEC/NRDC/SC assert that the Commission should immediately order DTE Electric to implement this new D1 rate, with improvements to make it more effective and cost-based. MEC/NRDC/SC's replies to exceptions, p. 64. MEC/NRDC/SC contend that the company's request for the Commission to reverse its ruling should be rejected because such request was already considered and rejected on rehearing in Case No. U-18255 and because the company's position is "without merit." *Id*., p. 65. MEC/NRDC/SC recall Case No. U-18255 and the recognition by the Commission that summer on-peak rates help send appropriate price signals, more closely align with COS, and that the current rate brings about "inaccurate price signaling and significant cross-class subsidization." *Id*. MEC/NRDC/SC further dispute the appropriateness of the option to opt-in, asserting that, "with an opt-out option, customers retain the same degree of choice and control as opt-in rates provide, but experience demonstrates that a large share of customers will use the default rate and its benefits may be achieved." *Id*., pp. 65-66.

As discussed in more detail below, the Commission upholds its decision from the 2018 orders on this issue to ultimately move toward summer on-peak rates but alters the implementation schedule and approach to allow for piloting of concepts as well as system development to support a smooth and cost-effective transition. *See*, April 2018 order, pp. 81-82, and June 2018 order, pp. 7-8.

1. Implementation Costs

To implement this new rate structure, DTE Electric estimated that it would cost: (1) $23 million for IT costs (for system redesign and programming), spanning 22 months; (2) $9.3 million in marketing and advertising costs during the first year the rate is implemented; and (3) $12 million for operational customer service costs also during the implementation year, with ongoing annual expenses of approximately $4 million thereafter. 5 Tr 1393-1395; 6 Tr 2106-2107; 7 Tr 3133-3136. With these estimated O&M costs, the company requested authorization to defer treatment and recovery of the one-time operating expenses, not to exceed $45 million (unless the IT costs are capitalized, then approximately $22 million). 7 Tr 3339.

The ALJ agreed that these O&M costs, up to $45 million, should be deferred and amortized. PFD, p. 260. Although the Staff raised concerns about regulatory asset treatment for certain marketing and educational costs (8 Tr 4147), the ALJ found that the costs did not appear to be significant in relation to the overall costs, and did not find any intention by the company to educate customers beyond the issue of this new summer on-peak rate structure. The ALJ also noted that DTE Electric has TOU rates, making it likely that educational materials and programs are already in place that could be leveraged for this purpose. PFD, p. 260.

The Commission disagrees with the ALJ with respect to the regulatory asset treatment for up to $45 million. While the Commission anticipated a proposal on this new D1 rate structure to include some implementation costs, DTE Electric's cost proposal lacks detail and is not adequately supported. The Commission seeks a more measured (i.e., less exorbitant) approach than that provided by the company in this case, and one that provides justification for the costs. The Commission therefore declines to authorize DTE Electric's regulatory asset treatment request at this time and looks to review more refined (and more vetted) implementation costs, including costs in the test year, in the company's next rate case, wherein the Commission directs DTE Electric to file a new proposal in line with the decisions below regarding the rate structure and implementation plan.

2. Rate Structure

Conforming to the requirements of the 2018 orders, DTE Electric proposed modifying its current D1 non-capacity charge structure (also its mirrored D1.6 rate structure) from a flat rate per kWh to a rate structure with summer on-peak and off-peak rates, specifically with an on-peak period of 4:00 p.m. to 9:00 p.m. on weekdays from June through September and with off-peak being for all other usage outside that on-peak period. 5 Tr 1343; 8 Tr 3863, 3866; Exhibit A-16, Schedule F3, pp. 2-3, 6-7. The company further averred that its proposed price differential between on-peak and off-peak rates ($0.01 per kWh), grounded in differentials represented by the historic summer MISO locational marginal price (LMP) from 2015-2017, is cost-based. 5 Tr 1344; 8 Tr 3864.

The ALJ recommended that DTE Electric's proposed non-capacity on-peak/off-peak charges be adopted, consistent with the Commission's decision in the 2018 orders to only apply changes to the non-capacity portion. PFD, p. 264. Given DTE Electric's acquiescence, the ALJ also recommended adoption of the Staff's proposal for the company's capacity rate to not vary between the summer on-peak and all off-peak periods (i.e., a flat per kWh capacity charge year-round). *Id*.; 8 Tr 3883, 4302. With respect to the pricing differentials, the ALJ highlighted DTE Electric's arguments that the Staff's primary recommendation to also apply the same differential to capacity rates (8 Tr 3883, 4302) and MEC/NRDC/SC's recommendation to adopt this Staff proposal (MEC/NRDC/SC's initial brief, pp. 154-155) do not accord with the 2018 orders. The ALJ adopted DTE Electric's proposed pricing differential for non-capacity rates. PFD, p. 264. And, while agreeing with the possible adverse outcomes of using larger price differentials for non-capacity rates, as primarily proposed by the Staff (for the use of LMP percentage differences to guide rate differentials versus LMPs in cents per kWh (8 Tr 4302)), the ALJ nevertheless recommended that the Staff's pricing differential proposal be further explored in the company's next rate case. *Id.*

In exceptions, DTE Electric states that, assuming the Commission does not reverse its prior directive, it largely agrees with the ALJ regarding rate structure but nevertheless takes exception to the ALJ's recommendation that the Staff's percentage proposal be further explored in the company's next rate case. The company questions the benefit of this recommendation, given the ALJ's rejection of the same as not comporting with the 2018 orders and the fact that DTE Electric will not have conducted an impact study of customers' reactions to this new pricing structure. The company further objects to this recommendation to the extent it places an initial burden on it "of either presenting evidence or proof on another party's flawed and rejected proposal." DTE Electric's exceptions, p. 124.

The Staff conversely asserts that the Commission should approve its proposed summer on-peak differential for non-capacity charges and to also apply the changes to the capacity portion. Contrary to the ALJ's reasoning about possible adverse outcomes of using its proposed price differential for the summer on-peak rate, the Staff argues that the ALJ "fail[ed] to consider Staff's argument and supporting evidence (including Company testimony) that projected shifts in usage and revenue fall outside of the test period in the instant case per both proposed implementation plans, and therefore have no bearing on the appropriateness of the change." Staff's exceptions, pp. 9-10. The Staff further asserts that the ALJ also failed to consider its evidence as to the appropriateness of its proposal to apply the on-peak differential to capacity rates, "as '[i]t is appropriate to charge more during summer on-peak hours for capacity, as this is when the capacity need is set.'" *Id.*, p. 10 (alteration in original).

MEC/NRDC/SC also except to the ALJ's recommended rejection of their recommendation to apply the summer on-peak rate to capacity charges and urge the Commission to disagree with the ALJ, otherwise leave the inverted block rate in place in this case, and then require DTE Electric to apply the summer on-peak rate to capacity charges in its next rate case. In support, MEC/NRDC/SC state:

> This is consistent with cost of service and more equitable to ratepayers. The main argument that has been raised against this change -- that it would require time and education to prepare customers -- is unavailing because there is time, piloting, and education built into the implementation plan for non-capacity summer on-peak rates to also accommodate summer on-peak capacity charges.

MEC/NRDC/SC's exceptions, pp. 10-11 (footnote omitted). MEC/NRDC/SC further object to a flat rate capacity charge because it "has not been developed, it does not reflect cost of service, and it would likely lead to adverse consequences for low-usage customers by eliminating the lower rate for the first 17 kWh delivered to the customer." *Id.*, p. 11. *See also*, *id.*, pp. 16-17. MEC/NRDC/SC further highlight the lack of technical or substantive rationale articulated by DTE Electric as to why summer on-peak rates should not apply to capacity charges, just the company's opposition that it is inconsistent with the 2018 orders. MEC/NRDC/SC additionally discuss the ample opportunity and capability for the company to implement summer on-peak capacity rates in conjunction with its proposed roll-out of summer-on peak non-capacity rates.

Further opposing the ALJ's recommendation, MEC/NRDC/SC also contend that the Commission should adopt the Staff's proposed non-capacity charge percentage differential versus the company's proposed $0.01 per kWh price difference between summer on-peak and all other off-peak hours. MEC/NRDC/SC aver that DTE Electric cited no evidence in support of its concern that the Staff's differential could have negative impacts and increase risk. In fact, according to MEC/NRDC/SC, one of DTE Electric's witnesses "acknowledged as much in his direct testimony, stating that, without the results of a pilot study, he could not ascertain the load impacts of the Company's proposed price differential." MEC/NRDC/SC's exceptions, p. 18 (footnote omitted).

In replies to exceptions, DTE Electric states that it supports the ALJ's recommended price differential. The company argues that "[t]he key problem with both Staff's and MEC/NRDC/SC's arguments is that, as the Company has explained, Staff's proposed methodology results in a differential beyond the actual price differential, and therefore should not be adopted (8T 3883-84)." DTE Electric's replies to exceptions, p. 48. DTE Electric further recalls testimony relative to customer acceptance, customer satisfaction, and risk, which did not appear to be refuted, along with the lack any reasoning as to why the Staff's percentage differential was superior. *See*, 8 Tr 3864-3865, 3883-3884.

With regard to the Staff's argument concerning a time-based rate for capacity charges, DTE Electric asserts that the Staff's testimony provides no discussion of the propriety of such a charge other than the assertion the Staff made about charging more for capacity in the summer. The company further contends that the ALJ accurately found the Staff's recommendation to be inconsistent with the April 2018 order.

DTE Electric contends that MEC/NRDC/SC's disagreement with the Staff's alternative proposal to have a flat capacity rate for summer on-peak and all off-peak periods, which the company agreed with and the ALJ recommended be adopted, is only based on "policy assertions and speculation rather than evidence to support their position (MEC/NRDC/SC Exceptions, pp 11, 16-17)." DTE Electric's replies to exceptions, p. 51. The company further contends that MEC/NRDC/SC's exceptions regarding the rate design for Rate Schedule D1:

> are in large part an attempt to offer new positions and evidence into the record after it closed, and should be dismissed by the Commission. In particular,

> MEC/NRDC/SC attempts to graft testimony from prior cases into this proceeding through its Exceptions (see for example MEC/NRDC/SC Exceptions pp 12-13). These seemingly contradictory statements conflict with Mr. Jester's testimony in this case . . . .

DTE Electric's replies to exceptions, p. 51. Nevertheless, according to DTE Electric, its D1 rate design should be approved; the Staff's and MEC/NRDC/SC's exceptions should be rejected; and the ALJ's recommendations should be adopted, as modified in the company's exceptions.

The Staff states, "While Staff agrees the Company should not be required to put forward Staff's proposal in the next case, as it should be approved in this case, Staff disagrees with all of the Company's claims regarding the competing rate structures." Staff's replies to exceptions, pp. 35-36.

In addressing MEC/NRDC/SC's exceptions, the Staff agrees that the ALJ erred in not approving the application of the summer on-peak differential to capacity charges, as articulated in Staff's exceptions, pp. 9-10, but disagrees with MEC/NRDC/SC that retaining the current capacity rate structure is appropriate. The Staff further disagrees with MEC/NRDC/SC that this failure to apply the summer on-peak differential to capacity charges violates MCL 460.11(1). According to the Staff, MEC/NRDC/SC's argument is "inaccurate," because "[t]he statutory requirement is only that rates in total be designed to recover each class' cost from that class; it says nothing about the manner in which this recovery should occur." Staff's replies to exceptions, p. 37 (footnote omitted). And, as to MEC/NRDC/SC's discussion of evidence in prior cases about TOU rates encouraging certain behavior, the Staff states:

> Staff reiterates that the purpose of the summer on-peak rate is not to stimulate behavior; it is to send appropriate price signals by properly reflecting costs as they are caused by customer usage. It is entirely possible for customer[s] to react to these price signals by changing nothing and choosing to bear the costs of their usage patterns; Staff takes no issue with this possibility.

Staff's replies to exceptions, p. 38 (footnote omitted). The Staff thus avers that the Commission should, in agreement with the Staff, implement the summer on-peak differential for capacity charges and reject the alternative of a flat rate set forth in MEC/NRDC/SC's exceptions.

MEC/NRDC/SC contend that the Commission should, primarily, apply summer on-peak rates to capacity charges and order DTE Electric to apply the Staff's larger differential for non-capacity charges or, in the alternative, and at a minimum, require the company to study these modifications in its next rate case. MEC/NRDC/SC's replies to exceptions, p. 69. MEC/NRDC/SC also assert that the "wider on-peak/off-peak differential" was not addressed in Case No. U-18255, as the rate design for this new rate was first presented in this case. *Id*., p. 70.

RCG disagrees with MEC/NRDC/SC and asserts that any differential between on-peak and off-peak charges should be minimized in this case because this is the first case where this rate structure may be imposed and rate shock to residential customers should be considered. RCG emphasizes the importance of a transition plan to apprise residential customers and help them understand this new rate structure. RCG supports eliminating the inverted block rate structure, contending the same "serves more as a penalty rate and revenue enhancement for the utility in contrast to an effective incentive provision to reduce energy consumption." RCG's replies to exceptions, p. 2. RCG further discusses how the inverted block rate adversely affects low-income customers, large families, and persons with health conditions; the inverted block rate's lack of any particular relationship to peak or seasonal peak load costs; and confusion, dissatisfaction, and billing abuses associated with the inverted block rate. RCG thus urges the Commission to "not go back to the problematic inverted block rate structure in this or any other case." *Id*., p. 3.

The Commission agrees with the ALJ that the pricing differential proposed by DTE Electric for the non-capacity rates is reasonable and cost-based. At this time, the Commission is not compelled to move forward with the pricing differentials proposed by the Staff given the potential impacts on certain customer segments. 8 Tr 3865, 3884. With respect to the non-capacity rates, the Commission is concerned with abrupt shifts in the overall rate design absent additional testing and customer education through pilots. Therefore, the Commission expects that the on-peak capacity (and non-capacity) rates should be tested as a combination but is concerned with establishing this as the default rate. The on-peak rates will be implemented through pilots in accordance with the implementation plan discussed below.

3. Implementation Plan

For transitioning residential customers to this summer on-peak rate, DTE Electric proposed the following recommended plan, along with an alternative plan:

> The Recommended Plan allows for piloting multiple rates to allow for a more comprehensive assessment of potential rate designs. This will help determine a rate design(s) that is best for our customers over the long-term. Given the significant costs and extended timing issues related to implementing a new rate structure, it is appropriate to assess and anticipate what other changes may be appropriate for the Company to best serve customers and offer additional options beyond the proposed summer on-peak rate. The Recommended Plan also allows for testing multiple messages among different customer groups and researching effective marketing and education.
>
> * * *
>
> The Alternative Plan allows for the piloting of only a single rate in phase one, whereas, the Recommended Plan allows for piloting multiple rates. Piloting only a single rate results in a projected go-live date of June 2021 compared to May 2022 for the Recommended Plan. The Alternative Plan provides less time to gather information and study customer behavior due to summer on-peak rate changes, and to develop solutions to potential issues identified during the pilot phase.
>
> The Company believes that we should obtain insight into customer interests during this transition to time of use rates. The Recommended Plan allows the Company time to work with its customers to introduce the Commission required time of use rates with the focus on minimizing any potential negative impact to our customers.

3 Tr 101-102.

The ALJ was persuaded by the Staff's recommendation that DTE Electric's alternative plan be approved (8 Tr 4301). PFD, p. 266. In her rationale, the ALJ found that there appears to be no need to pilot multiple rates, given her TOU rate structure recommendation above, and she also agreed with the Staff that several of the company's other residential program proposals could be piloted at any time. PFD, p. 266.

Disagreeing with the ALJ, DTE Electric contends that its recommended plan should be adopted for this transition (assuming again that the Commission does not reverse its prior directive, as requested above). The company disagrees with the Staff's and the ALJ's assertion that there is no need for testing, arguing that such an assertion is unsupported and contrary to research and best practices as set forth in Exhibit S-16.1. The company reiterates the need for and additional benefits of its recommended plan and argues that "[t]he suggestion that proposals can be piloted at any time neglects the fact that timing matters." DTE Electric's exceptions, pp. 127-128; 3 Tr 102-103.

In replies to exceptions, the Staff contends that, because the ALJ did not err in recommending that DTE Electric's alternative plan be approved, the company's exceptions on this issue should be rejected and the ALJ's recommendation should be approved. In support, the Staff states:

> First, the Company's proposal is not "testing"; allowing for system testing is the entire purpose of Staff's recommendation to go with the Alternative Plan rather than implementing immediately at the conclusion of the instant case. Staff responded to the Company's claims with regard to alternative rate structures, as properly considered by the ALJ in recommending approval of Staff's proposal, showing that they can be done any time and there is no real benefit to conducting such concurrent with summer on-peak rate implementation. (PFD, 264-266.) However, if the Commission is concerned about impacts on certain vulnerable customer groups, the opt-out structure mentioned elsewhere in Staff's replies is a more appropriate solution than the Company's proposal. As also discussed elsewhere, the data on these impacts should be used to inform such decisions, and the decision should therefore be made after the pilot period.

Staff's replies to exceptions, pp. 36-37.

MEC/NRDC/SC contend that the Commission should approve DTE Electric's alternative plan. In response to DTE Electric's argument that the alternative plan limits its ability to analyze and understand impacts to customers of this new rate, MEC/NRDC/SC assert:

> One flaw with this argument is that implementing the new rate according to the timeline in the Alternative Plan would not prevent the Company from later testing other rates and messages, with the results available to modify the new rate in the future. In other words, while more studies may provide valuable information and improve rate design and customer satisfaction, there is no need to await the results of additional studies before transferring to the new rate.

MEC/NRDC/SC's replies to exceptions, p. 67. MEC/NRDC/SC further argue that the company has not specified what other rates or messages need to be tested in its recommended plan, though it appears that DTE Electric is proposing to evaluate alternative opt-in rates, which the company already offers through several TOU opt-in rates, and by maintaining the traditional D1 rate design for customers who opt out of AMI. MEC/NRDC/SC conclude that the potential to test new rates is an insufficient basis to delay the transition of this new rate to May of 2022.

The Commission disagrees. Given the Commission's desire for DTE Electric to submit a more measured approach to this change to rate design (accompanied by reasonable cost projections) in its next rate case filing, and in light of recent issues with the company's billing system (*see*, Case Nos. U-18486 and U-20084), the Commission finds DTE Electric's recommended plan to be superior to the alternative plan and approves the recommended plan. The Commission believes that it is preferable to pilot multiple rates and to test multiple messages among different customer groups. The recommended plan allows the company an additional year to perform a thorough assessment and to develop a sound transitional plan for ratepayers, and the less-aggressive timeline should lead to more appropriate implementation costs. The Commission declines the request to reverse the 2018 orders; AMI has made this type of rate structure possible and DTE Electric needs to move forward with its provision. The Commission acknowledges the difficulty associated with the transition. In DTE Electric's next rate case filing, the Commission expects a comprehensive plan that offers a sound method for piloting the rate structure discussed herein and for making use of the data that is developed from the pilots, and that is supported by detailed information on the reasonable and prudent associated costs.

4. Shadow Billing

In its direct case, the Staff recommended that DTE Electric explore shadow billing capabilities in its next rate case, noting Commission support for shadow billing (along with a trial period for DR) in the March 29, 2018 order in Case No. U-18322, pp. 76-78. 8 Tr 4146.

The ALJ agreed with the Staff and recommended that DTE Electric be directed to present a plan for implementing shadow billing in its next rate case. Despite the company's contentions about practicability and the use of actual, historic billing determinants, the ALJ accentuated the Staff's point that the use of actual data, versus theoretical comparisons (through a rate calculator that forecasts a customer's bill as proposed by the company (6 Tr 2129)), would be more likely to increase customer interest in other programs. PFD, p. 261.

DTE Electric takes exception to the ALJ's recommendation and asserts that such recommendation should be rejected. The company reiterates why it believes shadow billing is not appropriate and helpful in this situation and why a rate calculator instead would be more useful. DTE Electric's exceptions, pp. 123-124. DTE Electric further avers that "there is nothing in the record to support this [referenced Staff] position. Reasoning that shadow billing would be 'more likely to increase customer interest in alternative programs') [sic] is also inapplicable to this situation where TOU rates are mandated, as discussed above." *Id.*, p. 124.

In replies to exceptions, MEC/NRDC/SC assert that the Commission should order DTE Electric to implement shadow billing. MEC/NRDC/SC state:

> Shadow billing allows a customer to understand and evaluate different rates by showing what their bill would be under different rates, based on actual monthly usage. Shadow billing would increase customer knowledge of time-based rates and would likely result in improved cost savings to customers and the Company. These are goals that the Michigan Legislature requires the Commission to promote, including increasing awareness of load management techniques such as time of use pricing, and working with customers to reduce annual demand and conserve energy through load management techniques.

MEC/NRDC/SC's replies to exceptions, p. 71. MEC/NRDC/SC discuss the facilitation of shadow billing by the company's near-completion of its roll-out of AMI meters and assert that shadow billing would assist with the benefit of demand reduction, which was discussed as a benefit nearly four years ago when AMI meters were approved and added to DTE Electric's rate base in Case No. U-17689. In that case, MEC/NRDC/SC point out discussion by the administrative law judge and the Commission about comparing and contrasting specific rate schedules and educating customers about the availability and advantages of alternative rates. According to MEC/NRDC/SC, however, "[n]early four years later, with AMI now rolled out, DTE still has not provided customers with a way to compare and contrast rates facilitated by AMI technology." *Id.*, pp. 71-72. MEC/NRDC/SC also reference Case No. U-18322 and assert that "DTE customers deserve the same benefits" provided to Consumers' customers through that case. *Id.*, p. 72.

The Commission agrees with the Staff, MEC/NRDC/SC, and the ALJ. With shadow billing, customers have more information readily available at their fingertips to make an informed decision about the best rate option for their usage and needs, based on current factors. The Commission therefore finds planning for the implementation of shadow billing appropriate for DTE Electric to include in its next rate case, particularly at this juncture given the forthcoming D1 rate switch to on-peak summer and all-other hours rates.

G. Distributed Generation Tariff (Rider 18)

1. Background and Legal Requirements

As required by the April 18, 2018 order in Case No. U-18383, DTE Electric requests approval of its proposed DG program tariff set forth in Exhibit A-16, Schedule F10 Revised. 8 Tr 3874-3878. The order in Case No. U-18383 was issued in response to the enactment of 2016 PA 341 (Act 341) and 2016 PA 342 (Act 342). Section 6a(14) of Act 341, MCL 460.6a(14), provides as follows:[27]

> Within 1 year after the effective date of the amendatory act that added this subsection, the commission shall conduct a study on an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. In any rate case filed after June 1, 2018, the commission shall approve such a tariff for inclusion in the rates of all customers participating in a net metering or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. A tariff established under this subsection does not apply to customers participating in a net metering program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211, before the date that the commission establishes a tariff under this subsection, who continues to participate in the program at their current site or facility.

Thus, Act 341 phased out net metering for new DG installations while grandfathering existing installations for a set time period under the law. The new methodology for pricing of DG must reflect "equitable cost of service" as determined by the Commission and must be applied in future rate cases, this instant case being the first application.

[27] In collaboration with MCL 460.6a(14), MCL 460.1183(1) states:

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

Additionally, Section 177(4) of Act 342, MCL 460.1177(4), provides as follows:

> 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. The credit shall appear on the bill for the following billing period and shall be limited to the total power supply charges on that bill. Any excess kilowatt hours not used to offset electric generation charges in the next billing period will be carried forward to subsequent billing periods. Notwithstanding any law or regulation, distributed generation customers shall not receive credits for electric utility transmission or distribution charges. 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 for energy at the commercial pricing node within the electric utility's distribution service territory, or for distributed generation customers on a time-based rate schedule, the monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.
>
> (b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.

Much of the contention over DTE Electric’s proposed DG tariff concerns the implementation of these statutory mandates.

As further background, and as discussed in Case No. U-18383, the Commission adopted (pursuant to MCL 460.6a(14)) an inflow/outflow tariff as an appropriate tariff reflecting equitable cost of service that rate-regulated electric utilities must file in any rate case filed after June 1, 2018. (Rate-regulated electric utilities are also able to propose their own DG tariff reflecting equitable cost of service, if desired.) Pursuant to an inflow/outflow tariff (attached as a rider to the customer’s retail rate schedule), incoming and outgoing electricity flows are independently measured and priced on an instantaneous basis, to ensure consistent and appropriate COS billing. Further, the “inflow” is the quantity of electricity supplied to the customer from the utility distribution system (i.e., any excess needed to meet customer needs after using on-site generation).

A power "outflow" is the quantity of electricity generated by the customer's DG system (such as a solar panel) that is not used on-site and thus delivered to the electric distribution system. The outflow credit is the rate, to be determined in a contested case proceeding such as this case, for each unit of energy that is exported from the DG customer to the utility distribution system. Under "true" net metering, which the legislation phased out, inflow and outflow over the course of the monthly billing period are netted against one another, and the customer was entitled to the full retail rate (including power supply, transmission, and distribution) for any excess amounts supplied to the utility on a net basis. This is different from charging and measuring inflow and outflow separately under the inflow/outflow methodology proposed by the Staff and acknowledged by the Commission in the April 18, 2018 order in Case No. U-18383 as representing "equitable cost of service." The specific rates and mechanics of the inflow/outflow tariff were disputed, as were alternative proposals including those presented by intervenors and DTE Electric.

On pages 266-274 of the PFD, the ALJ analyzed the legal requirements applicable to a DG tariff. She concluded, among other things, that the Commission has broad discretion under MCL 460.6a(14) to fashion a DG tariff and billing mechanism; that the Commission has determined that the inflow/outflow method is consistent with MCL 460.6a(14) and should be implemented; and that "while the Commission has determined that the outflow credit could be an amount other than those defined in MCL 460.1177(4)(a) or (b), the only proposals in this case that conform to those subsections, and that provide defined values for the outflow credit, are those presented by DTE Electric and the Staff." PFD, p. 273.

In exceptions, the Attorney General argues that the ALJ erred in several of her determinations concerning this tariff, primarily in failing to address the arguments and positions of parties other than DTE Electric and the Staff. The Attorney General contends that the ALJ, with regard to outflow, "dismissed a host of arguments and evidence put forth by other parties to this proceeding . . . ." Attorney General's exceptions, p. 30. The Attorney General also takes exception to the ALJ's subsequent determination in her PFD that other requests and suggestions by those parties were outside the scope of the case or not within the Commission's authority to grant. The Attorney General thus argues that the ALJ "failed to adequately consider all of the information and facts before her in the record in this case" and accordingly recommends:

> that the Commission disregard the ALJ's recommendations with regard to the outflow credit and the netting of inflows and outflows, and take into full consideration the positions of all parties when making a determination on the Distributed Generation Tariff. Conversely, the Attorney General recommends that the Commission accept the ALJ's recommendation with regard to the SAC [system access contribution], as the ALJ took into account the positions of all parties and therefore came to a fully informed, reasonable decision by giving adequate weight to all information in the record.

Attorney General's exceptions, p. 31.

Echoing the Attorney General's exceptions, the Joint Solar Advocates also express disagreement over the ALJ's decision to "not even consider the merits of intervenors' proposals that would more accurately and fairly reflect the value of DG." Joint Solar Advocates' exceptions, p. 2. In this regard (and discussed more fully below), the Joint Solar Advocates assert that the ALJ "should have considered [their] proposal to adopt a 'market transition adder' that would have provided solar users more accurate credit for the full range of benefits solar provides to the grid until the more comprehensive solar value study ordered by the PFD can be completed." *Id*.

In replies to exceptions, DTE Electric states, with regard to the Attorney General's assertion that the ALJ erred in not addressing matters, that the Attorney General "does not cite any legal authority or record evidence to support that proposition (AG Exceptions, pp 30-31)." DTE Electric's replies to exceptions, p. 53. The company goes on:

> The AG neglects that the Commission has limited authority and that the Commission's decisions must be based on the record. DTE Electric's Exceptions provide an extensive discussion of the law and evidence, and the Company presents a further discussion below in the context of specific issues. The AG's suggestion that the Commission should instead disregard the law and make arbitrary decisions without regard to the record merits no consideration.

DTE Electric's replies to exceptions, pp. 53-54 (footnotes omitted).

In reply, the Attorney General maintains her recommendation set forth above.

The Commission's decisions addressing the ALJ's legal findings are incorporated into the discussions of the DG issues, *infra*, particularly with respect to the outflow credit amount and the potential for netting.

2. Inflow Charge

A power inflow constitutes a retail purchase of electricity by a DG customer, and thus the underlying retail rate reflected in the utility's full service rate schedule for that particular customer would be applied. With its new DG tariff, DTE Electric proposed an inflow charge at the standard retail rate (for the underlying rate schedule that a new DG customer is attaching the rider to). 8 Tr 3597, 3874; Exhibit A-16, Schedule F10 Revised.

The ALJ, noting no serious dispute and finding the charge to be consistent with the Staff's DG report, recommended that the company's proposed inflow charge be adopted. PFD, p. 274.

No exceptions were filed. The Commission adopts the findings and recommendations of the ALJ.

3. Outflow Credit

a. Credit Amount

For outflow, DTE Electric originally recommended a credit based on LMP—specifically "the monthly average real-time locational marginal price for energy at the DTE Electric appropriate load node." 8 Tr 3597, 3875; Exhibit A-16, Schedule F10 Revised.

Finding the Staff's proposal to calculate the outflow credit based on power supply less transmission to be reasonable and well-supported, the ALJ recommended that it be adopted. PFD, p. 277. In her analysis, the ALJ discussed the Staff's point that DTE Electric's original outflow credit proposal based on LMP erroneously assumes DG outflows have zero capacity value (8 Tr 3430). PFD, p. 277. Albeit noting some interest in the company's alternative proposal on rebuttal that would include some compensation for capacity (8 Tr 3659), the ALJ nevertheless found such alternative proposal to have been introduced too late in the proceeding to be fully vetted in this case. PFD, pp. 277-278. The ALJ therefore recommended that DTE Electric's alternative proposal be explored in a future proceeding, also noting the Staff's recommendation that, once more meter data from DG customers is available, "the parties undertake a power-outflow study that will allow for more precise valuation of DG energy outflow," to which the company agreed if given the time to undertake such a study (DTE Electric's reply brief, p. 229). PFD, p. 278.

DTE Electric disagrees with the ALJ. First, the company contends that the ALJ ignored the title of MCL 460.1177 and claims that "MCL 460.1177(4) plainly does not say what Staff proposed and the [ALJ] now recommends." DTE Electric's exceptions, p. 140. Per the company, "There is no mention of 'excess kilowatt hours' as the [ALJ] seems to suggest. Instead, the statute discusses 'excess kilowatt hours' in the prior provisions regarding billing, but later, concerning the outflow credit, uses 'kilowatt hours,'" a distinction DTE Electric avers the Legislature intended and must be followed. *Id*., p. 141. DTE Electric recalls testimony comparing Acts 295 and 342 and further states:

> The PFD was also apparently persuaded to simply follow Staff's recommendation because the Commission addressed this issue in its April 18, 2018 Order in Case No. U-18383. The issue merits more consideration than it has received, however, and the current PFD/Staff position is contrary to statutory requirements, as

> indicated above. In Case No. U-18383, the Commission recognized the arguments made by DTE Electric and Consumers Energy that MCL 460.1177(5) restricts the Commission from approving outflow credits from offsetting any distribution charges applied to inflow since those charges are intended to recover the COS pursuant to Act 341. The Commission found that "this prohibition is explicitly directed toward credits for the portion of outflow that exceeds inflow under the modified net metering billing method[.]" (Case No. U-18383 April 18, 2018 Order, at 14-15) The U-18383 Order also stated that "[s]ection 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)." (*Id*. at 15) However, if Section 177(5) was directed only at modified net metering customers, the statute would not have referenced both "net metering and distributed generation customers." Reading the term "distributed generation customers" out of Section 177(5) renders that term surplusage or nugatory in contradiction to defined statutory construction case law. Moreover, the statute broadly refers to "any credit or ratemaking mechanism" and not to a specific credit granted to modified net metering. In addition, Section 177(5) specifically refers to charges, "established pursuant to section 6a of 1939 PA 3, MCL 460.6a", and thus the U-18383 Order statement that Section 177 does not apply to any tariff under Act 341, Section 6a(14) is contrary to the language of Section 177.

DTE Electric's exceptions, pp. 141-142 (footnote omitted). The company further disputes the ALJ's conclusion that Section 177(5) does not come into play, given her recommended rejection of DTE Electric's SAC charge, and contends that such conclusion "does not withstand reasoned scrutiny." DTE Electric's exceptions, p. 143. According to the company:

> Section 177(5) contains no "if" qualification and does not refer to only certain situations in which it "comes in to play." If Section 177(5) was only to come in to play under certain situations, the legislature surely could have crafted it to say so. The plain reading of Section 177(5) states that a charge for distributed generation customers established pursuant to section 6a of 1939 PA 3, MCL 460.6a shall not be reduced by any credit or other ratemaking mechanism for distributed generation. To ignore this provision of the law by apparently suggesting no charges will be established pursuant to section 6a of 1939 PA 3, MCL 460.6a is flawed. Again, nowhere in the law does it suggest 177(5) only applies "if" a charge is established, it simply states, "a charge established". Public Act 342 of 2016 added this section to limit the amount of charges that can be reduced by any credit or ratemaking provision of the distributed generation program. The statutory language is clear. Indeed, it is hard to conceive of a clearer Legislative intention.

DTE Electric's exceptions, p. 143. Moreover, the company contends that its proposed outflow credit is consistent with MCL 460.1001(2), MCL 460.11, and MCL 460.1177(4) and notes that the

Legislature has twice now, in Acts 295 and 342, made clear that there cannot be credits for transmission or distribution related to net metering and/or DG. DTE Electric further recalls testimony regarding the application of customer credits to all generation delivered into the utility's distribution system and discusses the Legislature's consideration of how that electricity is to be compensated, providing only two potential approaches, neither of which, of "no mere coincidence," include either a transmission or a distribution credit. DTE Electric's exceptions, pp. 144-145.

While being pleased that the Staff proposed a credit based on one of the two options above, which the ALJ agreed with, DTE Electric nevertheless excepts, maintaining its proposed use of LMP as the appropriate outflow credit. The company contends that "there is no data to support the proposition that distributed generation customers, on an aggregate basis, provide peak relief to the Company, and pointing to other jurisdictions provides no meaningful evidence with regard to DTE Electric's system (8T 3651-52)." DTE Electric's exceptions, p. 146. Pointing back to Exhibit A-42, Schedule FF1, DTE Electric re-illustrates that the Staff's proposed method could result in an outflow credit that exceeds the total power supply portion of a DG customer's bill, averring that, under the Staff's proposed approach, "a DG customer could just select whichever retail rate will maximize the outflow credit and potentially offset significant amounts of [the] distribution charge (8T 3889-90)." DTE Electric's exceptions, pp. 147-148. DTE Electric further disputes the evidence relied upon by the ALJ to conclude that outflow from DG customers should include compensation for capacity value, given the appearance by the Staff that "there is no present evidence of any capacity value for DG." *Id*., p. 149.

While not disagreeing with the ALJ's endorsement of the Staff's recommendation to conduct a power-outflow study, the Joint Solar Advocates nevertheless take exception to the lack of further discussion about the scope, timing, or methodology for this study and thus believe more detail should be included by the Commission in its final decision in this case.

GLREA takes exception to the ALJ's recommended outflow credit methodology on the basis that it fails to recognize additional reimbursement credits for other benefits. More specifically, GLREA asserts that "this formula fails to recognize that a number of diverse and geographically separate DG and net-metering customers reduce the costs of the company's distribution network over time, and can increase the reliability of the grid, in addition to reducing line losses, stress on the grid during peak days and hours, among other cost savings." GLREA's exceptions, pp. 1-2. GLREA suggests "an additional reimbursement credit of 1.5 or more cents per Kw [sic] hour, in addition to the Staff and PFD formula of reimbursement credits based upon power supply cost recovery costs minus transmission costs." *Id*., p. 3. GLREA also states that DTE Electric should be required to compile data and undertake studies collaboratively with the Staff and other stakeholders to determine added cost savings and benefits gained from these customers.

In replies to exceptions, DTE Electric maintains its position on its proposed outflow credit (using LMP) and argues that its proposed outflow credit is cost-based and complies with the law. MCL 460.1177(4)(a). The company argues that GLREA's exception suggesting an additional reimbursement credit is an improper exception because GLREA cites to nothing in the record for support. DTE Electric further avers that "GLREA's proposal is also similar to the credits proposed by other parties, which are prohibited by statute." DTE Electric's replies to exceptions, p. 61. And, as to the Joint Solar Advocates' assertion that the study should be based on full generation, DTE Electric argues this "effectively constitutes simply another attempt to obtain a DG subsidy, which should be rejected . . . ." *Id*., p. 62.

The Staff asserts that DTE Electric misunderstands Section 177(4) and inappropriately bases its outflow compensation methodology on this statute, which relates to modified net metering. The Staff states that the company's analysis of this statute is "incorrect and misleading" and reiterates that this statute does not prescribe the only two outflow compensation methodologies, as suggested by DTE Electric. Staff's replies to exceptions, pp. 15-16. The Staff cites MCL 460.6a(14) and maintains that its proposed inflow/outflow tariff satisfies the Legislative directive for an appropriate tariff reflecting equitable COS. According to the Staff, "The Company's method of interpretation divorces the individual sentences of [Section 177(4)] from one another and tries to imbue them with the Company's preferred interpretation through reading them in isolation," also known as cherry-picking. *Id*., p. 16. The Staff contends that DTE Electric narrowly focuses on the final portion of the provision. The Staff states:

> [R]eading all the sentences of [Section 177(4)] together, it is plainly obvious that there must be a credit for outflow that exceeds inflow. That credit applies to the following billing month and is capped at the power supply portion of that bill. Further, for customers for which this provision applies, the credits for outflow exceeding inflow cannot reduce transmission or distribution charges, in essence these customers are partially responsible for their usage of the distribution and transmission system. Lastly, the credit against future power supply charges is calculated by applying one of the two designated pricing formulas [Section 177(4) (a) or (b)] to the "excess kilowatt hours", i.e. the kilowatts in excess of the inflow. The Company's erroneous 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.
>
> * * *
>
> Simply put, with respect to any modified net metering tariffs that the Commission would approve, the Legislature intended outflow to be compensated at the full retail rate up to inflow, but DTE instead wants to disregard that legislative directive and compensate all outflow at the LMP.

Staff's replies to exceptions, pp. 17-18 (Section 177(4) (a) or (b) alteration in original).

Addressing the company's arguments about DG customers being mentioned in Section 177(4), the

Staff posits that this does not negate the section's exclusive applicability to the modified net metering billing method. The Staff states that the term DG or DG program as used in Act 341 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.

Id., pp. 18-19. The Staff further states:

> 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) can only be interpreted to mean that that the term "distributed generation" is inclusive of grandfathered modified net metering prior to the date the Commission approves a cost-based tariff under Section 6a(14).

Id., p. 19. According to the Staff, the only rational interpretation is that Section 177 does not bind or restrict the discretion of the Commission to approve an appropriate tariff under MCL 460.6a(14). The Staff concludes, with regard to Section 177(4):

> Ultimately, the Company's argument that Section 177(4) sets the exclusive compensation rates for all power outflows is incorrect. The section must be read as a whole, and in concert with MCL 460.6a(14). As the Commission already explained in its April 18, 2018 and July 12, 2018 [sic] orders in MPSC Case No. U-18383, the compensation methodology applies to grandfathered net metering, not to an "appropriate tariff reflecting equitable cost of service" such as Staff's inflow/outflow proposal. The Company's position neglects to take the section at its face. As such, the Commission should reject the Company's overly complex, inherently contradictory outflow compensation recommendation.

Staff's replies to exceptions, p. 20.

Specifically, on actual outflow compensation, the Staff disputes the company's proposal to base it on LMP, reiterating that such proposal presupposes zero future capacity value from DG program participants. The Staff discusses the DG program being "in a nascent stage," posits that “the door shouldn’t be closed because information is lacking at the time this case was filed,” and recalls testimony as further explanation about the development of data and its recommendation relative to a power outflow capacity study upon implementation of the inflow/outflow tariff. Staff’s replies to exceptions, p. 21, quoting 8 Tr 3432. The Staff further reiterates its dispute as to the company’s single-customer perspective about capacity value. The Staff states that it:

> maintains its position that outflow be compensated at power supply less transmission costs, and that the Company undertake a capacity study to confirm that coincident aggregate program outflows are relatively stable and predictable and to quantify the effective DG outflow capacity and value. And, until such time as this data is available, Staff reiterates that its outflow compensation method should be adopted because it “is simple, understandable to customers, creates a close connection between new compensation rates under an Inflow/Outflow billing method and existing compensation under NEM [net energy metering], and avoids the primary subsidy related to NEM which is the inclusion of the distribution charge in the outflow compensation formula.” 8 TR 3433.

Staff’s replies to exceptions, p. 22.

Addressing the Joint Solar Advocates’ suggestion that the DG tariff include compensation for full generation, not just exported generation, the Staff cites to its thorough response set forth in its reply brief, p. 21. Arguing nothing new is offered, the Staff avers that the Joint Solar Advocates’ exceptions on this should be rejected. Staff’s replies to exceptions, pp. 43-44.

MEIBC/IEI support the ALJ’s recommendation to reject DTE Electric’s proposal to compensate outflow using LMP but alternatively recommend that the Commission go beyond the Staff’s recommended outflow rate and set the outflow credit at the power supply component of the DG customer’s rate, without subtracting out transmission costs, to recognize the “full value of DG outflow . . . .” MEIBC/IEI’s replies to exceptions, pp. 5-6. MEIBC/IEI, however, urge the Commission, regardless of the outflow rate it chooses to adopt, to “explicitly acknowledge the impermanent and provisional nature of that rate, which should be updated on the basis of Staff’s recommended power-outflow study that will, according to the [ALJ], ‘allow for more precise valuation of DG energy outflow.'" *Id*., p. 6. MEIBC/IEI also support the additional power-outflow study details the Joint Solar Advocates request from the Commission in their exceptions.

The Joint Solar Advocates contend that DTE Electric's legal argument pertaining to MCL 460.1177 "directly conflicts with the Commission's prior orders in Case No. U-18383," particularly the April 18, 2018 order, which the company did not appeal. Joint Solar Advocates' replies to exceptions, pp. 2-3. The Joint Solar Advocates further aver:

> DTE's legal argument would create an irreconcilable conflict with other provisions of law. As recognized in the [ALJ]'s initial findings of fact and conclusions of law, "the Commission has great discretion under MCL 460.6a(14) to fashion an equitable, COS-based DG tariff." PFD at 273. The legislature would not have, on the one hand, directed the Commission to "conduct a study" to establish a cost-based and equitable tariff for DG under Section 6a while simultaneously predetermining the outcome to the two narrow options listed in Section 177. *Taylor v. Lansing Bd. of Water & Light*, 272 Mich. App. 200, 206, 725 N.W.2d 84, 88 (2006) ("This Court is well aware that a literal interpretation of statutory language is disfavored when that interpretation would lead to an absurd result").

Joint Solar Advocates' replies to exceptions, p. 3. The Joint Solar Advocates additionally contend that DTE Electric's proposal to compensate outflows at LMP is not equitable, because it ignores the value of solar generation, and while acknowledging that the Commission has not yet quantified this value in the company's territory, the Joint Solar Advocates nevertheless assert that the lack of this quantification does not support DTE Electric's proposal to assign it zero value. Instead, according to the Joint Solar Advocates, it supports their proposal for a market transition adder (as discussed more fully below). At a minimum, however, the Joint Solar Advocates endorse adoption of the ALJ's proposed outflow credit to start with until the precise value of DG can be ascertained.

MEC/NRDC/SC contend that the Commission should reject DTE Electric's exception on this issue. MEC/NRDC/SC assert that the company repeats unsuccessful arguments about the use of LMP for the outflow credit and that the ALJ correctly found other witnesses, other than DTE

Electric's witness, credible with regard to capacity and other values provided by DG exports. MEC/NRDC/SC aver that, "contrary to DTE's assertions that there is no evidence of DG capacity value, the record contains that evidence—including from DTE's own witness." MEC/NRDC/SC's replies to exceptions, p. 78, referencing 6 Tr 2387-2389, 8 Tr 3724. MEC/NRDC/SC assert that the Commission should defer to the ALJ's credibility determinations and the greater weight of the evidence demonstrating that "DG exports have capacity value by reducing the peak system loads." MEC/NRDC/SC's replies to exceptions, p. 78.

Based on the evidence in this case, the Commission agrees with the ALJ's recommendation to adopt the Staff's proposal to calculate the outflow credit based on power supply less transmission. The Commission agrees with the Staff that:

> [t]his approach is simple, understandable to customers, creates a close connection between the new compensation rates under the Inflow/Outflow billing method and existing compensation under NEM, and yet avoids the primary subsidy related to NEM which is the inclusion of the distribution charge (of the underlying sales rate schedule) in the outflow compensation formula. Vis-à-vis DTE's requested de-minimis compensation, use of the power supply component of the retail rate, excluding transmission, results in a more measured pace of adjustment from the existing effective level of compensation under NEM.

8 Tr 3433. The Commission also agrees with the Staff and the ALJ that Section 6a(14) provides the Commission with broad discretion to adopt a DG tariff "reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or a distributed generation program," and finds that the Staff's proposed outflow credit meets the requirements of the statute. The Commission additionally agrees with the ALJ's findings of fact and conclusions of law regarding the inapplicability of MCL 460.1177(4) as it relates to this inflow/outflow methodology and the statutory charge for the Commission to establish a tariff reflecting equitable COS for DG customers. PFD, p. 273. The PFD included the analysis provided by the Commission in its April 18, 2018 order in Case No. U-18383, pp. 13-15,

addressing the purported conflict between the proposed inflow/outflow mechanism and MCL 460.1177(4) and (5). PFD, pp. 269-271.

The Commission further notes, however, that even if the provisions of MCL 460.1177(4) applied in some way to limit the discretion authorized under MCL 460.6a(14) (which the Commission finds is not the case), the Staff's outflow credit based on power supply less transmission is harmonious with the credit described in MCL 460.1177(4)(b), which states that "[t]he credit per kilowatt hour for kilowatt hours delivered into the utility's distribution system shall be . . . [t]he electric utility's . . . power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period." This is what the Staff proposes. 8 Tr 3433. Moreover, the Staff's methodology ensures customers pay equitable COS as set forth in MCL 460.6a(14), including both distribution and transmission charges, as contemplated by MCL 460.1177(4)(b). This is because the Staff's methodology applies different pricing to inflows and outflows, and does not net inflows and outflows before applying the credit for power supply. Neither distribution nor transmission is included in the power supply credit under the Staff's proposal, meaning that customers are contributing to these charges consistent with COS principles and are not in conflict with MCL 460.1177(4)(b). 8 Tr 3433. As noted by the Staff, this is not the only method to sync up the provisions in Acts 341 and 342. Another approach referenced by the Staff would be to allow for the netting of inflows and outflows referenced in MCL 460.1177(4) (which the Commission maintains applies to modified net metering) but include a distribution charge that would account for the fact that the customer is being credited with distribution charges for the portion of outflow that is netted against inflow over the applicable billing period.

In the spirit of MCL 460.1177(4),[28] albeit not bound, the Commission also finds it reasonable to limit the application of outflow credits to the power supply component of a customer's bill, as proposed by DTE Electric. 8 Tr 3889. With this limitation, outflow credits would then not offset transmission or distribution charges, and any excess over and above power supply charges in the current bill would be carried over to subsequent billing periods.

The Commission further finds that it would be premature to direct the company to undertake a power-outflow study at this time. Nevertheless, the Commission will continue to monitor implementation and adoption of DG tariffs in other upcoming electric rate cases as required by the April 18, 2018 order in Case No. U-18383 and MCL 460.6a(14), and may reconsider the necessity of a power-outflow study at a later date.

b. Netting of Excess Generation

Based on its interpretation of MCL 460.1177(4) and (5), DTE Electric insisted that netting of inflows and outflows is not allowed for new DG customers and that the outflow credit applies to all kWh delivered into its distribution system, not just net outflows, with no credits being allowed for transmission or distribution charges. 8 Tr 3643, 3647-3648.

The ALJ agreed with the Staff's recommendation regarding netting inflows and outflows and recommended that it be adopted. PFD, pp. 280-281. More specifically, the ALJ agreed with the Staff that MCL 460.1177(4), when read in its entirety, indicates that the outflow credit applies to excess generation during the billing period and not all kWh delivered into the distribution system as asserted by DTE Electric (Staff's initial brief, pp. 92-93). The ALJ also found MCL

[28] The relevant portion of MCL 460.1177(4) states, "The credit shall appear on the bill for the following billing period and shall be limited to the total power supply charges on that bill. Any excess kilowatt hours not used to offset electric generation charges in the next billing period will be carried forward to subsequent billing periods."

460.1177(5) to be irrelevant, given her recommendation to reject the company's SAC charge (discussed in more detail below).

In exceptions, DTE Electric expresses confusion over the ALJ's recommendation. More specifically, the company states:

> The [ALJ] . . . recommends that, "the Commission should approve the Staff's recommendation with respect to netting inflows and outflows." (PFD p 281) The Company is somewhat confused with this finding and what it is intended to suggest, as Staff's proposed Distributed Generation Program does not propose to net inflow and outflows. Staff's proposed tariff (Staff Exhibit S-11.0) proposes that outflow, defined as the metered quantity of the customer's generation not used on site and exported to the utility, be credited, and that inflow, defined as the metered inflow delivered by the Company to the customer, be billed according to the retail rate schedule. Thus, the Company clarifies that Staff's proposed inflow/outflow methodology does not include netting inflows and outflows (this is further made clear in Staff's testimony, 8T 3423, 3436-7, and in Staff's Initial Brief.)

DTE Electric's exceptions, p. 149.

The Staff likewise indicates that the ALJ mischaracterized its position on net excess generation, specifically in her concluding statement on page 281 of the PFD where she stated, "'Consistent with the analysis above [with respect to interpreting Act 341 Section 177] the Commission should approve the Staff's recommendation with respect to netting of inflows and outflows.'" Staff's exceptions, p. 12 (alteration in original). The Staff argues that the ALJ "leap[ed] from a correct interpretation of the modified net metering billing method (pursuant to Section 177(4)) to a final recommendation that outflow compensation under an Inflow/Outflow tariff approved by the Commission should include netting consistent with Section 177." *Id*. The Staff explains the origin of this final recommendation—the ALJ's erroneous initial finding of fact and conclusion of law that the only proposals that conform to MCL 460.1177(4)(a) or (b) are those presented by DTE Electric and the Staff—and expounds:

> The primary reason that Staff undertook an analysis of Section 177 in this proceeding (and agreed to by the [ALJ]) was to demonstrate that DTE's outflow

> compensation proposal does not conform to Section 177, since the billing method prescribed by the section (modified net metering) requires netting at the full retail rate for a portion of power outflows. Despite the fact that the crediting formulas proposed by DTE and Staff (for all power outflows) match Section 177(4) (a) and (b), both DTE's and Staff's proposed Inflow/Outflow tariffs exclude netting and thus do not conform to Section 177.

Staff's exceptions, p. 13. The Staff further contends:

> Ostensibly, the [ALJ] recommends adoption of a Rider 18 tariff based on an Inflow/Outflow billing method, however, the PFD's outflow compensation recommendation dramatically transforms the Rider 18 tariff into a modified net metering tariff. In effect the [ALJ] guts both DTE's and Staff's proposed Inflow/Outflow tariff, replacing it with a modified net metering tariff. No party supported such a proposal in this proceeding. The [ALJ]'s recommendation to include netting pursuant to the modified net metering billing method reintroduces the very subsidy (i.e. the net metering subsidy) that MCL 460.6a(14) explicitly outlawed. The recommendation is in direct contravention of the mandate for the Commission to establish a DG tariff that equitably recovers the cost of service for utility revenue requirements and is thus illegal.

Staff's exceptions, p. 13. Moreover:

> Although not explicitly stated, the [ALJ] appears to suggest that the Commission is bound by Section 177 in formulating a cost-based DG tariff. No findings were made by the [ALJ] that an Inflow/Outflow tariff fails to reasonably reflect an equitable cost of service, or otherwise fails to comport with MCL 460.6a(14). Thus, the only basis for the [ALJ]'s recommendation to net inflows with outflows is an implicit legal finding that the Commission is restricted to a modified net metering tariff in implementing MCL 460.6a(14). This assertion is clearly in conflict with the [ALJ]'s initial findings of fact and conclusions of law . . . . No legal analysis was put forward by the [ALJ] to support this dramatic reversal in theory.

Id., p. 14. The Staff next addresses an additional problem with the ALJ's recommendation with regard to the necessary conclusion that true net metering was eliminated by the Legislature, a proposition the Staff states was addressed and negated by the Commission in its March 18, 2009 order in Case No. U-15787, with Act 341 having made no amendments to Act 295 to suggest otherwise. The Staff further states:

> The [ALJ]'s analysis regarding Section 177 only establishes that modified net metering is different than true net metering, in that it divides power outflows into

> two categories, power outflows credited within a billing month on an energy basis (e.g. the full retail rate), and excess power outflows carried forward to future billing periods at one of two pricing formulas. The analysis does not establish that true net metering is eliminated, nor that modified net metering is now the exclusive tariff available under the DG program.

Staff's exceptions, p. 15. According to the Staff, MCL 460.6a(14) is clear and explicit about developing a cost-based billing framework, with which its proposed inflow/outflow tariff fully complies. The Staff further notes:

> The [ALJ] is inconsistent where, in [her] implicit finding that Section 177 binds the Commission to a Section 177 modified net metering billing method, the ALJ suggested that the Company's alternative proposal should be discussed further . . . .
>
> If, as the [ALJ] suggests, the Commission is bound by Section 177, then future outflow valuation studies would be meaningless, as Section 177 strictly defines only two compensation formulas for excess power outflows, thus prohibiting alternative compensation methods such as those based on valuation-of-solar studies.

Staff's exceptions, pp. 15-16. The Staff additionally contends that, if the Commission adopts the ALJ's recommendation "to approve a modified net metering tariff for the DG program based on the incorrect assumption that the Commission is limited to MCL 460.1177(4)," the Commission would then "be precluded from ruling on the issue of whether or not transmission charges should be subtracted from compensation - at this time, as recommended by Staff in its case-in-chief." *Id*., p. 16. The Staff maintains that Section 177 applies only to modified net metering, as clearly addressed by the Commission in its April 18, 2018 order in Case No. U-18383.

MEC/NRDC/SC indicate concurrence with the ALJ's interpretation of MCL 460.1177(4) as applicable to excess generation in a billing month rather than all generation but highlight that "it differs from Staff's recommendation to apply the credit to all outflows, not just excess outflows." MEC/NRDC/SC's exceptions, p. 2. MEC/NRDC/SC thus file exceptions on this issue "to clarify that the correct outcome would apply Staff's outflow calculation methodology to excess outflows, after netting inflows and outflows for the month." *Id*. *See also*, *id*., pp. 8-9.[29]

In replies to exceptions, DTE Electric repeats its argument that the ALJ mischaracterized the Staff's position with regard to the netting of inflows and outflows. DTE Electric further states, "The Company agrees with Staff that net metering subsidies must be eliminated, as discussed above. The Company also generally agrees with Staff that the [ALJ]'s analysis is flawed; however, Staff's and MEC/NRDC/SC's analyses are also problematic. The correct legal analysis is set forth in DTE Electric's Exceptions." DTE Electric's replies to exceptions, pp. 59-60.

The Staff disagrees with MEC/NRDC/SC's recommendation to apply Staff's proposed power-supply-less transmission outflow compensation formula only to excess outflows. The Staff argues that MCL 460.6a(14) is "clear, unambiguous, and is permissive, not restrictive," in calling for an appropriate tariff that reflects COS, and that MEC/NRDC/SC's position fails to satisfy this directive. Staff's replies to exceptions, p. 22. Pointing to the July 12, 2017 and April 18, 2018 orders in Case No. U-18383, and recalling the Commission's decision that Section 177(4) applies to modified net metering, the Staff states:

> MEC's proposal is essentially advocating for the continuation of modified net metering but fails to account for DG customers usage of the grid, evidenced by a lack of a grid charge. In essence, MEC's proposal maintains the very same cost subsidy that MCL 460.6a(14) aims to rectify. Thus, because the MEC's proposal fails to satisfy this bedrock legislative directive that the new tariff be cost-based, the Commission should reject it.

Staff's replies to exceptions, pp. 22-23. Again negating the applicability of Section 177 here, the Staff quotes MCL 460.6a(14) and, focusing on the word "tariff" within MCL 460.6a(14), states:

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[29] MEC/NRDC/SC expressly agree with the ALJ's recommendation for the outflow credit to be based on power supply less transmission, and for outflow credits to apply to a customer's entire bill, including future bills. MEC/NRDC/SC's exceptions, p. 9.

> A tariff necessarily encompasses an underlying foundational pricing model (e.g. billing method), and associated rates, charges, terms and conditions of service. Thus, a tariff is a schedule or set of schedules of rates, charges, fees, etc. - including rate structure or rate design, all of which provide the components needed to calculate a bill.

Staff's replies to exceptions, p. 24. The Staff further reiterates the unrestricted nature of MCL 460.6a(14) and the direction provided by the statute for an appropriate tariff that, in the judgment of the Commission, reflects an equitable COS.

Finding the Staff's position and recommendation on this issue to be "somewhat unclear," GLREA states that it opposes such position and recommendation "if Staff is suggesting that the net metering and distributive generation customers are to be charged for all energy inflows, at full retail rates, even for inflows not actually obtained from the utility (because said energy has been generated on-site via net metering or distributive generation)." GLREA's replies to exceptions, p. 3. GLREA contends that such an approach would be "egregiously inequitable" and unsupported by any COS studies or principles presented in this case. *Id*.

The Attorney General states that she supports the following position set forth by MEC/NRDC/SC in their exceptions:

> MEC's proposal is to credit outflows at the Power Supply component of the full-service retail rate, less transmission, and to apply the outflow credits to their entire bill as well as future bills. Along with that, MEC proposes to apply those provisions only to the excess outflows during the month and, consistent with MCL 460.1177 and the ALJ's reasoning, net inflows and outflows during the month. The AG agrees with MEC's interpretation and analysis in this area and recommends that the Commission follow MEC's proposal.

Attorney General's replies to exceptions, p. 40 (footnotes omitted).

MEIBC/IEI state that they support the ALJ's recommendation to approve a netting of inflows and outflows pursuant to MCL 460.1177(4), with the outflow credit applicable to excess generation, but also join with MEC/NRDC/SC "in urging the Commission to clarify that such netting of inflows and outflows should take place monthly, across the period covered by each billing cycle, and that any excess outflows resulting from such monthly netting be credited at the outflow credit rate . . . ." MEIBC/IEI's replies to exceptions, p. 5.

In discussing the calculation of an outflow credit for DG and their continued support for a market transition adder until the more comprehensive solar value study recommended by the ALJ can be completed, the Joint Solar Advocates nevertheless aver that "the 'monthly netting' concept proposed by the ALJ would also represent a reasonable proxy for DG value and would be well within the Commission's 'broad discretion' under MCL 460.6a(14)." Joint Solar Advocates' replies to exceptions, p. 1. Agreeing, however, that the Staff did not recommend monthly netting of inflows and outflows, the Joint Solar Advocates contend that the Commission should amend page 281 of the PFD to clarify this mischaracterization. The Joint Solar Advocates also agree with the Staff that "Section 177(4) does *not* limit the Commission's discretion to adopt a cost-based and equitable DG tariff and the Commission should clarify the PFD to the extent that it creates any ambiguity or conflict with the Commission's April 18, 2018 Order in U-18383." Joint Solar Advocates' replies to exceptions, p. 4.

MEC/NRDC/SC respond to the Staff's exceptions about the ALJ's determination about the netting of inflows and outflows pursuant to MCL 460.1177(4) and argue:

> Ironically, the ALJ based her PFD, in part, on Staff's own interpretation of MCL 460.1177(4), which correctly pointed out that the statute requires intra-month netting. Ultimately, Staff objects to the application of MCL 460.1177(4) to DG customers, notwithstanding its own reliance on the statute in Staff's briefing to the ALJ. As MEC-NRDC-SC have consistently maintained throughout this case, the distributed generation program required in MCL 460.1173-.1185 requires netting of inflows and outflows during the month and continues to apply even after adoption of any charge pursuant to MCL 460.6a(14).

MEC/NRDC/SC's replies to exceptions, pp. 73-74 (footnotes omitted). MEC/NRDC/SC also contend that "[w]hat Staff apparently objects to is that the ALJ applied MCL 460.1177(4) at all."

Id., p. 76. MEC/NRDC/SC state that "Staff's argument is convoluted and, ultimately, inconsistent with the statutory text." MEC/NRDC/SC's replies to exceptions, p. 77. MEC/NRDC/SC thus aver that the Commission must reject the Staff's exception on this issue and adopt the ALJ's recommendation "to net inflows and outflows during the month and to monetize only the excess outflows based on the power supply charge less transmission." *Id*., p. 74. *See also*, *id*., p. 77.

MEC/NRDC/SC also dispute DTE Electric's exception seeking to monetize all DG outflows at LMP and maintain that "MCL 460.1177(4) accounts for outflows in two different ways: (1) outflow up to the level of inflows are accounted for with netting; and (2) the excess outflows are accounted for by creating a 'credit.'" *Id*. MEC/NRDC/SC assert that DTE Electric's exception on this issue should also be rejected and that the statute should be applied as written, with the netting of inflows and outflows during the month and a monetized credit to the excess generation during the month.

Having considered the evidence and arguments offered by each party, the Commission agrees with the ALJ's analysis of MCL 460.1177(4) but only to the extent that such provision and analysis applies to modified net metering. As stated in the April 18, 2018 order in Case No. U-18383, p. 15, "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)." The Commission further finds it necessary to correct the PFD to clarify that the Staff, in its position regarding its proposed inflow/outflow billing mechanism, did not advocate for the netting of inflows and outflows.[30] Rather, as clarified by the Staff in exceptions, "The Inflow/Outflow tariff does not include netting, thus rectifying the subsidy inherent to both the true and modified net-

[30] The Commission notes that DTE Electric also did not advocate for the netting of inflows and outflows. *See*, 8 Tr 3643; Exhibit A-16, Schedule F10 Revised.

metering billing methods and allowing for recovery of an equitable cost of service." Staff's exceptions, pp. 18-19. And, although the Commission agrees with the Staff that under the Commission's broad discretion under MCL 460.6a(14) inflows and outflows could be netted, in order to be COS-based a grid charge may also need to be applied. As discussed previously, there are two basic options to ensure COS with DG customers contributing to the cost of the grid. One option is the Staff's inflow/outflow (without netting) methodology and the second option is netting of inflows and outflows as contemplated in MCL 460.1177(4) with a separate grid charge. *See, e.g.*, Exhibit MEC-162, p. 16 of 134. The record in the instant case is inadequate for the development of a reasonable and cost-based grid charge. In addition, a fixed grid charge for DG customers would be problematic, in terms of sending proper price signals, for those DG customers who incorporate battery storage into their systems. The Staff's inflow/outflow methodology encourages the customer to use as much generation onsite as possible and could therefore complement solar plus storage installations. *Id.*, p. 59 of 134. For clarification, in response to GLREA, this Staff proposal does not entail payment of the retail rate for the customer's generation consumed onsite; that is not the definition of inflow. It is only for energy drawn from the utility's system and explicitly excludes any consumption served by onsite generation. For these reasons, including those quoted above by the Staff in testimony, the Commission finds the Staff's proposal to credit all outflows at power supply less transmission to be the most reasonable and prudent methodology based on the record in this case. 8 Tr 3433; Exhibit S-11.0.

c. Market Transition Adder

In discussing the outflow credit, ELPC specifically advocated for inclusion of a market transformation adder,[31] in line with the Staff's proposal on page 17 of its DG report filed on February 21, 2018, in Case No. U-18383.[32] 6 Tr 2373-2374, 2427.

The ALJ found this request to be outside the scope of this case or not within the Commission's authority to grant and therefore declined to address it further. PFD, p. 274.

The Joint Solar Advocates disagree with the ALJ and argue that it is "not clear why a market transition adder designed to equitably approximate the grid value of DG is beyond the discretion of the Commission to implement," considering the ALJ's acknowledgment of the Commission's broad discretion under MCL 460.6a(14) to develop an equitable COS-based DG tariff and the Staff's recommended consideration of a market transformation adder in its DG report. Joint Solar Advocates' exceptions, p. 3. The Joint Solar Advocates cite to testimony suggesting "that a conservative and reasonable estimate of . . . unaccounted [value of solar (VoS)] benefits would result in a market transition adder of approximately 4.5 to 5 cents/kWh beyond the avoided energy and capacity values offered in Staff's recommended rate." *Id*., citing 6 Tr 2450-2451.

In replies to exceptions, DTE Electric, when discussing its SAC charge, addresses the Joint Solar Advocates' proposal for inclusion of a market transition adder in conjunction with GLREA's proposal for inclusion of a service access contribution credit and states:

> The fundamental problem with GLREA and ELPC's positions is that they improperly seek to increase DG subsidies (through additional unjustified payments to DG customers) rather than eliminate them. Eliminating DG subsidies is in accordance with the law and the whole point of the SAC charge (i.e., DG customers should pay for the distribution infrastructure they use).

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[31] Market transformation adder and market transition adder are synonymous in this case.

[32] *See*, https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000016WftAAE.

DTE Electric's replies to exceptions, pp. 54-55. The company contends that the Joint Solar Advocates' vague suggestion that the Commission has authority to include a market transition adder to avoid market disruption "asks the Commission to maintain the current net metering subsidies." *Id.*, p. 56. DTE Electric repeats discussion about the Commission's lack of authority to authorize cost shifting; the Legislature's mandate to move away from subsidized net metered rates; and how the company's SAC charge proposal complies with the law and ratemaking principles. The company argues that the Joint Solar Advocates' suggestion, along with GLREA's suggestion for a positive service access contribution credit, "would be further steps in the wrong direction that . . . should be rejected as contrary to MCL 460.1177(4)." *Id.*, p. 57. DTE Electric further disputes the Joint Solar Advocates' "inaccurate[ ] claims that there is 'undisputed evidence' that the outflow credit does not reflect the full value of distributed generation (ELPC Exceptions, p 4)" and argues that it provided "competent, material and substantial evidence presented by multiple witnesses supporting the Company's proposed credit methodology as capturing the full value of distributed generation, as well as evidence on why Staff's proposal is flawed." DTE Electric's replies to exceptions, p. 60.

The Staff argues that a market transition adder should be rejected and recalls the testimony of one of its witnesses in support (8 Tr 4245). Staff's replies to exceptions, p. 43.

ABATE urges the Commission to reject this proposal. ABATE states:

> The ALJ recommended that this be developed in a separate proceeding where DTE can be required to provide certain information regarding "value" of the output of distributed generation ("DG"). There are many issues involved in establishing a rate not the least of which is to make sure that it is cost based and not a tool for creating new subsidies. In addition, the new proceeding could also review DTE's argument that MCL 460.1177(4) dictates how to calculate the "out flow" price.

ABATE's replies to exceptions, p. 11.

As part of their discussion on netting, the Joint Solar Advocates reiterate their continued support for their recommended market transition adder and place particular import on this adder, along with MEC/NRDC/SC's monthly netting approach, "to avoid shocks to the DG solar market that could undermine the financial viability for citizens desiring the opportunity to generate their own power and add value to the grid." Joint Solar Advocates' replies to exceptions, p. 5. According to the Joint Solar Advocates, the Commission could adopt a market transition adder alone or in combination with the monthly netting approach, a proposal they contend the ALJ erred in dismissing without consideration of its merits. The Joint Solar Advocates further highlight the Commission's broad discretion under MCL 460.6a(14).

The Commission finds that ELPC's/Joint Solar Advocates' request to include a market transition adder should be rejected. Considering the Commission's decisions above, including a market transition adder to the Staff's inflow/outflowing billing mechanism would not be COS-based**.** The Commission is limited by the law, and, based on the record before us in this proceeding, it appears the adder would amount to the type of subsidy the Legislature intended to remove through the passage of Acts 341 and 342. The Commission recognizes, however, that new information and experience with DG systems may shed light on the costs and benefits to the electric system. This was recognized in the April 18, 2018 order in Case No. U-18383, p. 11, in which the Commission stated:

> The cost and benefit impacts associated with DG customers are not static, but can vary based on a multitude of factors including location, utility infrastructure conditions, weather, and the number of DG customers on the grid, among other factors. As the Staff explained in the DG Report, the Inflow/Outflow tariff is an adaptable framework that will allow the Commission to collect the data and information necessary to accurately capture the costs and benefits attributable to DG customers in a way that could not be done under traditional net metering. As explained above, the statute directed the Commission to develop a tariff, which is distinct from a rate, or specific numerical value. The Staff fulfilled that directive by

> developing the Inflow/Outflow tariff, which is a billing mechanism that can be adapted over time to ensure conformance with COS principles even as conditions change.

The Commission further finds insufficient evidence on this record to calculate a market transition adder, even if it were deemed appropriate for inclusion. *See*, 8 Tr 4245-4246.

4. System Access Contribution Charge

For new DG customers taking service under rates without demand charges, DTE Electric proposed a SAC charge "that assigns a cost per kW AC [alternating current] of nameplate system capacity based on the system-cost responsibility of distributed generation customers." 8 Tr 3598, 3875-3876; Exhibit A-16, Schedule F9.

The ALJ agreed with ELPC, MEC/NRDC/SC, MEIBC/IBI, Soulardarity, and the Staff, who opposed DTE Electric's proposed SAC charge, and found the charge to be neither cost-based nor equitable. PFD, p. 285. The ALJ, referring to MCL 460.6a(14), found that the proposed SAC charge is not equitable because it "is not based on a DG customer's actual usage of DTE Electric's distribution system but rather on the size of the customer's system." PFD, p. 285. The ALJ agreed with the Staff's point that "'[i]n 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.'" PFD, p. 286, citing the Staff's initial brief, p. 87.

DTE Electric takes exception and argues that the ALJ's discussion "skips over the whole point of the SAC charge"—that, without it, the company will be unable to recover the full cost of DG customers' distribution infrastructure use. DTE Electric's exceptions, p. 131. The company states:

> The [ALJ] instead focuses on criticizing the SAC methodology (which is inaccurate as discussed below), but it is important to keep in mind throughout this discussion

> what the [ALJ] is really recommending – that DG customers pay nothing despite the facts that (1) their inflow (and the resulting Company cost recovery) is reduced by the intermittent on-site usage of intermittent on-site generation; yet (2) the Company's fixed distribution system is and must <u>always</u> be available to serve the DG customer if the customer's generation system goes down and to balance, second by second, the changes in the intermittent generation from the distributed generation system (8T 3897-98).

DTE Electric's exceptions, p. 131. DTE Electric further takes issue with the ALJ's finding that the company failed to quantify the costs associated with the SAC. DTE Electric asserts that the evidence provided in this case demonstrates that there would be cost-shifting without the SAC charge and cites to evidence about the services provided by the grid to DG customers. DTE Electric's exceptions, pp. 131-132, referencing 8 Tr 3670-3672 and Exhibit A-34, Schedule X-5. The company further reiterates evidence about DG customers' additional grid use, added costs to the distribution system, and greater peak demand. DTE Electric's exceptions, p. 132, referencing 8 Tr 3804-3804, 3650 and Exhibit A-16, Schedule F11. The company additionally contends that the ALJ did not recognize that the SAC charge would be recalculated with each rate case and that it is appropriately tailored to each DG customer's use based on their installed capacity. The company argues that "those parties advocating for continuing cost shifting to other DTE Electric customers neglect that the Commission lacks authority to authorize cost shifting to subsidize the DG industry and the Legislature has mandated the transition away from subsidized net metering rates (*e.g.*, 8T 3593-96)." DTE Electric's exceptions, pp. 134-135 (footnote omitted).

As to the ALJ's assertion that its SAC proposal is not cost-based, DTE Electric states that the ALJ "is accurate to the extent that [she] recognizes that volumetric charges to DG customers will be reduced, but ignores that volumetric inflow rates do not fully account for utility costs incurred on behalf of DG customers," which, the company argues, without some mechanism like the SAC charge, then results in distribution costs not being recovered from these customers, thus leading to cost shifting and a burden on non-DG customers. DTE Electric's exceptions, pp. 135-136. In furtherance of its argument that its SAC charge is cost-based, DTE Electric states:

> The SAC is also supported by cost of service evidence on the record. Mr. Dennis explained that the SAC was designed to recover fixed costs of the distribution system for both residential and commercial secondary customers. The distribution costs being recovered are developed by the Company's cost of service witness Mr. Lacey (Exhibit A-16, Schedule F-1.2). Based on the revenue requirement for these classes, DTE Electric developed a cost-based distribution charge (line 5, Exhibit A-16, Schedule F9) which was used in development of the SAC. Thus, the SAC is cost based (8T 3898; Exhibit A-42, Schedule FF2). The SAC is designed using the Company's distribution cost of service study (numerator) and the Company's forecasted load (denominator) so that the Company will recover its revenue requirement, nothing more or nothing less (8T 3899).

DTE Electric's exceptions, p. 136. The company further reiterates that the SAC charge would not lead to double recovery, as the SAC charge would not compensate for outflow, would not double charge for distribution services, and was calculated by utilizing on-site consumption.

As far as discrimination, DTE Electric states that "there is nothing inappropriate about treating different things differently, and DG customers are plainly different than other customers . . . ." DTE Electric's exceptions, p. 137 (footnote omitted). The company notes the SAC charge is only designed to recover DG customers' allocable costs of the company's distribution system and is just one rate option that customers can choose if suitable to their needs.

The Joint Solar Advocates indicate strong support for the ALJ's recommended rejection of DTE Electric's proposed SAC charge. Joint Solar Advocates' exceptions, p. 1.

GLREA agrees with the ALJ's recommended rejection of the SAC charge but takes exception with the reverse, specifically the ALJ's failure to consider a positive service access contribution credit reimbursement or payment to DG and net-metering customers for the cost savings and benefits they provide. According to GLREA, the ALJ's recommended rejection "does not go far enough." GLREA's exceptions, p. 3; 8 Tr 4001-4004.

In replies to exceptions, and as stated above, DTE Electric addresses what it contends is the fundamental problem with GLREA's proposal for inclusion of a service access contribution credit. DTE Electric's replies to exceptions, pp. 54-55. The company repeats that it quantified costs associated with its proposed SAC charge, presented evidencing showing that its proposed SAC charge is cost-based, and that, without the SAC charge, subsidization would occur.

The Staff re-asserts that DTE Electric's arguments in favor of its SAC charge should be rejected.

The Attorney General contends that the ALJ adequately considered and found, based on evidentiary support, that DTE Electric's proposed SAC charge should be rejected. The Attorney General thus avers that the Commission should adopt the ALJ's findings and recommendation. Attorney General's replies to exceptions, p. 41.

MEIBC/IEI express their continued opposition to DTE Electric's proposed SAC charge and, thus, urge the Commission to adopt the ALJ's recommendation and disregard the company's exceptions. MEIBC/IEI's replies to exceptions, p. 7.

The Joint Solar Advocates reiterate that DTE Electric's inequitable SAC charge should be rejected. Joint Solar Advocates' replies to exceptions, p. 2.

GLREA states that it opposes DTE Electric's exceptions on this issue and reasserts, considering reduced costs and increased benefits, that "there is persuasive logic and rationale for the adoption of a System Contribution Credit, or positive payment to net metering and distributive generation customers, rather than an SAC charge." GLREA's replies to exceptions, p. 4.

MEC/NRDC/SC assert that DTE Electric's exception on this issue must be rejected, because the company's proposed SAC charge is not based on an equitable COS and thus violates MCL 460.6a(14). MEC/NRDC/SC contend that the company relies on the false premise that its SAC charge reflects COS, "even though it is undisputed that the SAC was based on amount of customer usage that a customer self-serves and, consequently, the company does not serve." MEC/NRDC/SC's replies to exceptions, p. 78. MEC/NRDC/SC agree with the Staff that DTE Electric's SAC charge "'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.'" *Id*., p. 79.

The Commission agrees with the Staff, the Attorney General, the Joint Solar Advocates, GLREA, MEIBC/IEI, and the ALJ and adopts the ALJ's recommendation to reject DTE Electric's SAC charge in this case. As stated by the ALJ, the company's SAC charge is neither COS-based, as required by MCL 460.6a(14), nor equitable. PFD, pp. 285-286. As ELPC noted, the utility's method for calculating the SAC charge explicitly relied on the distribution revenue deficiency and not on any cost to serve. Exhibit A-16, Schedule F9, lines 8-9. DTE Electric based the charge on the size of the customer's system rather than the customer's actual usage. The Commission finds that this does not comport with the statutory requirements and is unreasonable from a COS ratemaking perspective.

The Commission also rejects GLREA's suggestion for inclusion of a positive service access contribution credit for the same reasons the Commission rejects inclusion of a market transition adder in this case.

5. Other Distributed Generation Issues

a. Eligibility of Net Metering Customers to Increase System Size

The Staff proposed that, if a net metering customer expanded their net metering system before the company's new DG Rider 18 went into effect, then the customer could add an additional 10-

year grandfathered timeframe to the customer's participation in the net metering program. 8 Tr 4177.

The ALJ agreed with DTE Electric that the tariff provisions in the company's current Rider 16 tariff should prevail and that DTE Electric's net metering program was, from the beginning, only for 10 years (DTE Electric's reply brief, p. 233). PFD, p. 286.

No exceptions were filed. The Commission therefore adopts the findings and recommendations of the ALJ. *See* MCL 460.1183; MCL 460.6a(14). However, any grandfathered Rider 16 customer who expands their generation system after the effective date of Rider 18 will no longer be eligible for Rider 16 at all, considering the impracticability of both riders applying. 8 Tr 3902.

b. Customer Termination or Withdrawal from the Program

DTE Electric originally proposed that, if a new DG customer under Rider 18 ceases to participate in the DG program, any remaining outflow credit balance would be forfeited. 8 Tr 3875.

The ALJ found the company's revised proposal for Rider 18 to be reasonable and recommended that Rider 18 be amended to reflect that, upon termination from the DG program, "customers moving out of their residences should receive a refund of any unused credit balance. However, customers who end their participation in the program and remain in the residence, will have any banked credits applied to future bills." PFD, p. 287.

In exceptions, DTE Electric contends that the ALJ misstated its position on the matter, "which was that customers moving out of their residence should forfeit any unused outflow credit, and that if a customer remained at the same residence that they should be able to continue to use their credit banks to offset power supply charges for up to twelve months (8T 3892)." DTE Electric's exceptions, p. 150.

The Commission accepts DTE Electric's clarification of its revised position but nonetheless finds the following blended version most reasonable and consistent with the Commission's decision above regarding the limitation of outflow credits to power supply: Upon customer termination from the Distributed Generation Program, any existing credit on the customer's account will be either applied to the power supply portion of the customer's bill or refunded to the customer if the customer leaves the residence. 8 Tr 3892, 4172. As can be seen, the Commission is not adopting DTE Electric's 12-month limitation.

c. Customer Interconnection Cost Reporting

Given the requirement that customers shall pay all interconnection costs pursuant to MCL 460.1175(1), the Staff recommended that DTE Electric "include these costs and a description of the interconnection equipment as part of its annual DG Program reporting," proposing language in Rider 18 to address this. 8 Tr 4175; Exhibit S-11.0, p. 6 (Original Sheet No. D-116.00).

The ALJ noted DTE Electric's objection to this requirement citing concerns about customer privacy and recommended that the company and the Staff work together informally to come up with a mutually agreeable way to address the Staff's recommendation.[33] PFD, p. 287.

DTE Electric indicates appreciation for the ALJ's suggestion that the company and the Staff work together if the Staff's proposal is accepted but contends that the ALJ did not mention its other concerns with the Staff's proposal. DTE Electric states:

> The proposed reporting will not achieve its intended purpose as a pricing signal to other developers, as interconnection costs will be highly dependent on the type of generation, size of the generator, the distance from existing DTE Electric facilities,

[33] The Commission notes that the Staff's original recommendation was clarified as being limited to only Category 1 DG program customers. Staff's initial brief, p. 138.

> and the location of the generator and its proximity to other generators on the system. The pricing signal would give an inaccurate picture of the actual costs that may be incurred at any given location (8T 3797). Furthermore, it is an unprecedented request that will raise the general cost to administer the DG program which would have to be passed along to all DTE Electric customers (8T 3798). Finally, the scope of the proposed reporting is unclear (8T 3796). Thus, Staff's proposed reporting on interconnection costs should be rejected.

DTE Electric's exceptions, p. 150.

GLREA excepts to any interconnection or other charges being applied to DG or net-metering customers and asserts that the ALJ vaguely referenced, and appeared to recommend, such charges but "without any reference to the evidentiary record" and without "sufficient discussion or reasoning." GLREA's exceptions, p. 4. Here, GLREA recalls cost savings it asserts these customers provide and asserts no showing of additional metering costs that could be attributed to DG and net-metering customers, averring that AMI meters should be capable of handling related data from these customers.

In replies to exceptions, DTE Electric asserts that GLREA "neglects, among other things, that: 'The customer shall pay all interconnection costs.' MCL 460.1175(1)." DTE Electric's replies to exceptions, p. 61. The company further argues that GLREA "also does not identify anything in particular that it finds objectionable about the PFD, nor any basis to do anything different, so there is no basis to consider this matter." *Id*.

The Staff expresses disagreement with DTE Electric's arguments set forth in exceptions and maintains that the company should work with the Staff to formulate reporting requirements for interconnection costs. In support, the Staff recalls testimony from one of its witnesses (8 Tr 4175) and proclaims that "its request is not unduly burdensome and would be beneficial to the Company and its ratepayers." Staff's replies to exceptions, pp. 28-29.

The Commission agrees with the Staff and the ALJ and finds the ALJ's recommendation reasonable considering the requirement under MCL 460.1175(1) that "[t]he customer shall pay all interconnection costs."

d. Premises Requirement

In exceptions, Soulardarity contends that the ALJ, on pages 266-287 of the PFD, failed to consider its argument regarding the barrier the "premises requirement" in DTE Electric's DG Tariff (Rider 18)[34] creates for ratepayers who do not own their home but want to participate in DG, particularly low-income residents and people of color who rent or live in multi-unit dwellings. Soulardarity's exceptions, pp. 8-9. Soulardarity specifically argues that neither Act 341 nor Act 342 require ratepayers to own their own home in order to participate in DG:

> While Act 342 "limit[s] each customer to generation capacity designed to meet up to 100% of the customer's electricity consumption for the previous 12 months," the Act neither restricts the location of the eligible electric generator nor mentions "premises" at all. The fact that stakeholders are now engaged in discussions about third-party community energy projects as a result of Commission orders in U-18351 and U-18352 does not rectify the fact that the imposition of the "premises requirement" goes beyond what the statutes require.

Soulardarity's exceptions, p. 8 (alteration in original, footnote omitted). Soulardarity thus asserts that the "premises requirement" should be rejected and recommends DG policies not exclude low-income persons based on their living arrangements.

In replies to exceptions, DTE Electric maintains that Soulardarity's suggestion should be rejected. The company argues:

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[34] Per the generator requirements in DTE Electric's proposed Rider 18, p. 4 (Original Sheet No. D-114.00):

> The Eligible Electric Generator(s) must be located on the customer's premises, serving only the customer's premises and must be intended primarily to offset a portion or all of the customer's requirement for electricity.

> Soulardarity neglects that property and other legal rights (including those regarding certain "premises") are a fundamental aspect of utility law (and law in general). For example, Rule 411 [Mich Admin Code, R 460.3411] provides for a utility's right of first entitlement to serve premises as follows:
>
> (1) As used in this rule:
>
> (a) "Customer" means the buildings and facilities served rather than the individual, association, partnership, or corporation served.
>
> * * *
>
> (11) The first utility serving a customer pursuant to these rules is entitled to serve the entire electric load on the premises of that customer even if another utility is closer to a portion of the customer's load" [sic] (R 460.3411(11)).

DTE Electric's replies to exceptions, pp. 62-63 (omission in original). DTE Electric references two Michigan Supreme Court decisions demonstrating that "[t]his is just one example of how utility investments are based on established and stable law, with significant consequences arising from a change in that law." *Id*., p. 63. And, as further support that generation be located at the participating customer's site or premise, the company also repeats its references to MCL 460.1173(6)(b) and MCL 460.1179. DTE Electric thus argues that, because "[f]undamental principles of law and utility regulation cannot be cast aside simply because they affect a desired outcome . . . ," Soulardarity's exception on this issue should be rejected. *Id*., p. 64.

The Staff asserts that the Commission should reject Soulardarity's recommendation to waive the premises requirement. The Staff notes agreement with the "apt discussion of this issue" in DTE Electric's reply brief. Staff's replies to exceptions, pp. 30-31, quoting DTE Electric's reply brief, pp. 231-232. According to the Staff, "Untethering distributed generation from a site requirement would result in significant issues from what would essentially be a virtual generator, which is not contemplated in any of the statutes pertaining to DG." Staff's replies to exceptions, p. 31.

The Commission agrees with DTE Electric and the Staff and finds that Soulardarity's suggestion to remove the premises requirement should be rejected, for the reasons set forth by DTE Electric and the Staff. As noted by DTE Electric, Rule 411 of the Commission's Technical Standards for Electric Service states that the customer is the "buildings and facilities" served, and does not include an individual or family. In addition, MCL 460.1173(6)(b) and MCL 460.1179 state that the DG equipment will be installed on the "customer's" site, which, according to the Commission's rules, is a physical location and not an individual's premises.

H. Distributed Generation Rider (Rider DG/Rider 14)

DTE Electric proposed modifying the language in this rider so that, going forward, it would not apply to renewable resources, which, according to the company, are addressed by its proposed Rider 18. 8 Tr 3878-3879.

The ALJ first discussed the Staff's suggestion to rename Rider DG to avoid confusion with the company's new DG Rider 18 and DTE Electric's follow-up suggestion, upon agreement, to rename Rider DG to Rider 14. 8 Tr 3887, 4176. Given no opposition, the ALJ recommended that this change be approved. PFD, p. 287. Next, the ALJ agreed with the Staff that this rider should remain open to customers who do not qualify for Riders 16 or 18 (8 Tr 4175-4176). PFD, p. 288; 8 Tr 4176. The ALJ also disagreed with the company's *Union Carbide* arguments, specifically stating "*Union Carbide* does not apply to this circumstance, in light of the fact that the issue concerns an existing tariff (and rate) which should be made available to customers who do not qualify for Rider 16 or Rider 18." PFD, pp. 288-289.

DTE Electric excepts and argues that the ALJ neglected the guidance set forth in *Union Carbide*. DTE Electric states:

> The [ALJ] suggests that anything involving "an existing tariff (and rate)" is within the Commission's authority. Instead, the Commission's authority is limited. The

> Commission has "ratemaking" authority; however, almost any aspect of DTE Electric's business the Commission regulates may affect rates to some degree, and the Commission cannot expand its authority by mischaracterizing its decision as "ratemaking." See *Consumers Power Co v Public Service Co*, 460 Mich 148, 157-58; 596 NW2d 126 (2004) (rejecting MPSC's "ratemaking" defense and vacating MPSC's order as unlawful).
>
> DTE Electric is not presently choosing to provide additional programs, as indicated above. The Staff's contrary proposal (and now the [ALJ]'s recommendation) is inappropriate in the absence of the Company's agreement. The [ALJ] recommendation to unilaterally change DTE Electric's program unlawfully encroaches on utility management, as illustrated by *Ford Motor Co v Public Service Comm*, 221 Mich App 370, 385, 387-88; 562 NW2d 224 (1997) . . . .

DTE Electric's exceptions, p. 152.

In replies to exceptions, the Staff avers that the Commission should reject DTE Electric's proposal to limit Rider DG to non-renewable generation. The Staff contends that the ALJ "properly found that the existing Rider DG should not be revised or closed to additional renewable generators" and recalled testimony on its behalf. Staff's replies to exceptions, p. 29, quoting 8 Tr 4175-4176. Addressing the company's *Union Carbide* arguments, the Staff argues that DTE Electric "misconstrues the import of the holding." Staff's replies to exceptions, p. 29. The Staff quotes the ALJ's discussion on *Union Carbide* on pages 194-195 of the PFD and contends the same reasoning, as applied to the sale for resale issue, applies here. Referencing MCL 460.54 and MCL 460.6, the Staff avers, "Clearly, the matter of whether to limit the types of renewable generation covered by a particular utility tariff falls within the purview of the Commission's authority." Staff's replies to exceptions, p. 30.

The Commission agrees with the Staff and the ALJ and adopts the ALJ's recommendations. The rider involves a rate, and DTE Electric proposed that it not apply to renewable resources. As stated by the ALJ, pursuant to *Union Carbide*, the Commission is within its authority to regulate and enforce reasonable rates. Therefore, except for changing the name of this rider to Rider 14, the Commission finds that this rider should not be revised or closed to renewable resources going forward. 8 Tr 4175-4176.

I. Net Metering (Rider 16)

For its existing net metering tariff (Rider 16), DTE Electric proposed additional language be added to state that "it will be unavailable for new customer on-site generation after the new Distributed Generation Program (Rider 18) is implemented." 8 Tr 3878; Exhibit A-16, Schedule F10 Revised. The company further proposed the following three criteria to determine if an applying customer (applying for the existing net metering tariff before it closes) is considered to be participating in the program:

> 1) They have submitted a complete application to DTE before the new distributed generation tariff is approved by Commission Order in this rate case[.]
> 2) If the application is deemed deficient by DTE, the deficiencies must be corrected by the effective date of the Commission Order in this rate case[.]
> 3) If the application has been approved pursuant to the above timing, the customer must have a completed and approved installation within six months of application approval. Any unbounded time-period in which an approved customer may install their distributed generation asset and receive the net metering rate may create a system planning and operational issue. Moreover, six months is a reasonable time-period in which to construct a distributed generator, a premise with which the Commission has concurred.

8 Tr 3607-3608 (footnote omitted).

The ALJ was persuaded by MEIBC/IEI's concerns and arguments. 8 Tr 3526-3527. Although she noted that it is unlikely that such a situation will occur, the ALJ found that the following provisions based on the Commission's April 18, 2018 order in Case No. U-18383, p. 17, should apply in situations where a customer submits a last-minute interconnection and net metering application:

> (1) a customer is "participating" in the interim DG program (i.e., net metering) if the customer has a "completed" application pending before the utility at the time the DG tariff is approved; (2) a customer who has an application filed with the

> utility before the effective date of the DG tariff may still be allowed to participate in net metering if the application is found deficient, provided the applicant cures the deficiency within 60 days.

PFD, p. 291. The ALJ stated that there was no dispute that a customer with a completed application is considered participating in this interim DG program for 10 years. Finally, she noted that the Commission's informal and formal complaint processes for related situations not anticipated or addressed in this case. *Id*.

DTE Electric disagrees with the ALJ's recommended 60 days to cure a deficiency, arguing that it would invite the submission of incomplete applications. The company maintains that its proposed language is appropriate and reiterates that:

> any new requirements necessary to make an application complete based upon DTE Electric's own rules would only apply going forward, and not to applications that had already been deemed complete. DTE Electric would also incorporate changes to interconnection requirements, the details of which presumably will be determined during the stakeholder process established in Case No. U-20344 (8T 3799).

DTE Electric's exceptions, p. 153.

In replies to exceptions, the Staff avers that DTE Electric's rejection of 60-day period to cure a deficiency specifically contradicts the Commission's requirements for utilities converting to the new DG tariff. Staff's replies to exceptions, p. 27. The Staff opines, "Without these criteria in place, the Company may find itself in the position of defending itself against customers who believe their applications were deemed incomplete to prevent the customer from taking service under net metering terms and conditions." *Id*. The Staff contends that the ALJ's recommendation is correct; consistent with the April 18, 2018 order in Case No. U-18383, p. 17; and should be adopted.

The Commission agrees with the ALJ and finds that her recommendations should be adopted. As pointed out by the Staff, on page 17 of the April 18, 2018 order in Case No. U-18383 the

Commission stated an applicant shall have "60 days from the date of notification by the utility to cure the deficiency." Therefore, the Commission finds that the language proposed by MEIBC/IEI and adopted by the ALJ should be approved.

J. Retail Open Access Rider EC2—Return to Full Service

Given changes in the energy landscape, DTE Electric proposed applying the less restrictive provisions of its retail access service rider (RASR) to all customers returning to full service. In other words, "[n]on-residential customers that participate on Retail Access Service would no longer be required to satisfy a two-year minimum stay on Retail Access Service nor would they be subject to MPP [market priced power] charges when they return to Full Service." 5 Tr 1229-1231.

The ALJ agreed with Energy Michigan that, as part of DTE Electric's proposal, the company should, instead of the proposed one-year minimum stay, retain the two service options (12-month and short term) for a customer returning to full service (7 Tr 3092). PFD, p. 298. In her rationale, the ALJ discussed Energy Michigan's point that the cap on electric choice could be raised or eliminated, and also found that DTE Electric failed to demonstrate why the short-term option would allegedly cost the company money, and how much. PFD, p. 298; 5 Tr 1260. However, regarding the meter data access issues raised by Energy Michigan, the ALJ agreed with DTE Electric and found that such issues should be addressed as part of the ongoing proceeding in Case No. U-18485. PFD, pp. 298-299, citing 5 Tr 1262-1263; 7 Tr 3094-3102; Exhibit EM-5.

DTE Electric disagrees with the ALJ's recommendation that both of the company's return-to-service options be retained. DTE Electric's exceptions, p. 154. DTE Electric cites simplification and fairness as reasons to adopt its proposal, stating:

> As a practical matter, keeping a short-term option provides no additional customer flexibility and costs the Company to maintain that option. Currently, any customer returning to full service who would like to take retail access service again must follow the allotment process as defined in the April 28, 2017 Order in Case No.

> U-15801 et al. DTE Electric reached its 10 percent cap on retail access service participation in November 2009 and few additional customers have been awarded an allotment to participate since then. Therefore, there is no need for a short-term return to full service provision as it provides no value to a customer, which is evident from the fact there are currently no customers taking Option 2 – Short-Term Service. Eliminating the short-term option would also eliminate any gaming concerns associated with short-term rate switching (5T 1259-60).

DTE Electric's exceptions, p. 155.

Energy Michigan excepts to the ALJ's recommendation that its requested changes to the customer meter data rules within this tariff be addressed in a separate proceeding. Noting that the Staff did not object to its proposed changes, Energy Michigan argues that the ALJ failed to substantively address this issue, and instead recommended that the proposed changes be addressed in Case No. U-18485. Energy Michigan states:

> The problem with the ALJ's proposal is that Energy Michigan has already been participating in the U-18485 proceeding to make clear that the 'third parties' referred to in that proceeding do not include AESs. The U-18485 proceeding is focused on data access for "third parties" and an Alternative Electric Supplier ("AES") is not a "third party" for purposes of that tariff and proceeding. For the customer on Electric Choice, the AES is the supplier of energy, and so stands in the same relationship as the utility to the full service customer – *i.e.*, it is the second party in the contractual relationship, not a "third party." It would therefore lead to confusion of the issues if matters of supplier access to customer data were to be folded into a proceeding where Energy Michigan has been making the point that AES's [sic] are not third parties and should not be addressed in the tariff revisions being dealt with there.
>
> Moreover, the docketed proceeding in Case No. U-18485 is not a contested case proceeding . . . . Therefore, Energy Michigan would lose the benefits of a contested proceeding, where evidence can be submitted and tested, if it is required to attempt to advance the issue in U-18485 rather than the general rate case. Furthermore, although both Energy Michigan and the Retail Energy Supply Association made filings in the docket on July 20, 2018 and July 2, 2018, respectively, seeking clarification of the definition of "third parties," the Commission never responded to those filings, nor acknowledged in any of its two subsequent orders, dated October 24, 2018 and January 18, 2019, respectively, that those filings were even made. Therefore, Energy Michigan submits that the proceeding in Case No. U-18485 is not a viable proceeding in which to decide these tariff issues.

Energy Michigan's exceptions, pp. 2-3. For these reasons, Energy Michigan argues that this rate case is the appropriate forum for revising this tariff. Exhibit EM-5.

In replies to exceptions, DTE Electric disagrees that Energy Michigan's proposed changes are either necessary or appropriate. The company reiterates its current process of providing AESs with metered billing data monthly, along with the process if there is a meter reading change that affects billing. DTE Electric further repeats that its current process does not harm marketers, who can elect to have the company act as their meter data management agent and who are also not obligated to take such service from the company. DTE Electric reiterates that requiring the company to submit an additional copy of data is duplicative, given the hourly metered values available through MISO's website.

The company further avers that, while the Staff did not object to these changes, the Staff did not find any convincing reason to adopt them. DTE Electric's replies to exceptions, p. 65. According to DTE Electric, "Energy Michigan's position boils down to acknowledging that the Company's reasoning sounds good 'in theory,' but speculating that there might be some problem 'in practice' (Energy Michigan Initial Brief, p 6). Such speculation is not a sound basis for a decision by the Commission." DTE Electric's replies to exceptions, p. 65. DTE Electric claims that this is "an unnecessary solution in search of a problem," as "Energy Michigan has not cited any instance where an Alternative Energy Supplier has not receiving timely or accurate metering data." *Id*.

The Staff acknowledges the concerns raised by Energy Michigan. Noting recent developments in Case No. U-18485, the Staff states:

> Because Case No U-18485 is not a contested case and is nearing completion and because Energy Michigan has already testified to and submitted a marked-up tariff of their proposed changes recommended in this case, Staff believes Energy

> Michigan raises valid concerns regarding this issue being addressed in Case No. U-18485.

Staff's replies to exceptions, pp. 46-47.

Energy Michigan contends that the ALJ's support for retaining both return to service options should be affirmed. Energy Michigan argues that DTE Electric has no made no effort in exceptions to explain how retaining option 2 (the short-term option) costs the company money or what the resulting cost is. As such, according to Energy Michigan, DTE Electric's exception on this issue should be disregarded.

The Commission agrees with the ALJ that DTE Electric should retain the two service options (12-month and short term) in its RASR for a customer returning to full service. As stated by the Staff, "should there be new legislation enacted that opens up electric choice for full participation, these tariff provisions would retain flexibility for the customer and protect the utility from short-term customer switching." 8 Tr 4226. Further, DTE Electric has failed to provide testimony or exhibits to substantiate its monetary concerns with the short-term service option.

Given the focus of Case No. U-18485 and the stage of that proceeding, as articulated by the Staff and Energy Michigan, the Commission also finds it appropriate to address Energy Michigan's requested changes to the customer meter data rules in this tariff in this case. In that regard, because AESs have a similar relationship to choice customers as the utilities have to full-service customers, the Commission finds that Energy Michigan's proposed meter data changes within Exhibit EM-5 are reasonable and should be approved.

K. Other Tariff Changes

DTE Electric proposed the following other tariff changes:

> Design variable distribution rates to approach a uniform rate for all residential secondary rate schedules, with individual variable distribution rates capped at a 20% increase.

* * *

> . . . [T]he modification to tariff language, consistent with billing rule R460.113, clarifying that in cases where the Company is missing interval meter data that customers on time of use rate schedules, are to be charged the off-peak (lower) rate. In addition, . . . modification to Section C6.5 (c) (4) of the Company's tariff with respect to customer line extension.

8 Tr 3859. *See also*, 8 Tr 3867-3868, 3872-3873.

The ALJ noted that no party disputed the requested changes, and therefore she recommended that they be approved. PFD, p. 299. The ALJ also recommended adoption of the Staff's requested change to DTE Electric's dynamic peak pricing (D1.8) rate (to lower the maximum number of critical peak events from 20 to 14) (8 Tr 4303), which the company agreed with (3 Tr 384) and no other party opposed. PFD, p. 299.

No exceptions were filed. The Commission adopts the findings and recommendations of the ALJ.

THEREFORE, IT IS ORDERED that:

A. Based on this order's findings adopting a May 1, 2019 through April 30, 2020 test year, a jurisdictional rate base of $17,058,834,000, an authorized rate of return on common equity of 10.00%, an authorized overall rate of return of 5.48%, and a jurisdictional revenue deficiency of $125,097,000, combined with the expiration of the Tax Cuts and Jobs Act of 2017 Credit A of $148,237,000,[35] DTE Electric Company is authorized to implement rates that increase its annual electric revenues by $273,334,000, on a jurisdictional basis, over the rates approved in the April 18 and June 28, 2018 orders in Case No. U-18255.

[35] The Commission recognizes that the actual revenue change associated with the expiration of Credit A may differ.

B. DTE Electric Company is authorized to implement rates consistent with the revenue deficiency approved by this order on a service rendered basis for service provided on and after May 9, 2019, as reflected in Attachment A (a summary of revenue by rate class), Attachment B (tariff sheets), and Attachment C (calculation of the capacity charge as updated by this order) to this order. Within 30 days of the date of this order, DTE Electric Company shall file tariff sheets substantially similar to Attachment B. When filing the tariffs consistent with those ordered, DTE Electric Company shall also update the Standard Allowance amounts on Tariff Sheet C-30.00, Section C6.2(4)(a), to be consistent with the rates approved in this order. Due to the size of Attachment B, it is not physically attached to the original order contained in the official docket or paper copies of the order, but is electronically appended to this order, which is available on the Commission's website.

C. DTE Electric Company shall submit annual reports in this docket on the Enhanced Tree Trimming Program, with information broken out according to Table 12 at 3 Tr 231, and also broken out for the city of Detroit. Information addressing the city of Detroit shall include all tree trimming efforts included in any utility programs. The annual report shall include the information described in this order. The first report is due March 1, 2020, and an annual report is due on March 1 of each year thereafter in this docket. DTE Electric Company shall also file the Tree Trimming Effectiveness Report, as described in this order, in this docket.

D. DTE Electric Company is authorized to implement the Charging Forward program for electric vehicles as described in this order.

E. In its next electric rate case filing, DTE Electric shall file a comprehensive plan for piloting new Rate D1 summer on-peak capacity and non-capacity rates, as described in this order.

F. DTE Electric Company is authorized to implement a distributed generation tariff as described in this order**.**

G. DTE Electric Company shall submit an updated nuclear decommissioning study for the Fermi 2 nuclear plant with its next electric rate case application.

H. DTE Electric Company shall file a capacity cost calculation in accordance with the calculation method approved in this order in its next electric rate case application.

I. DTE Electric Company's accounting requests are approved as set forth in this order.

J. DTE Electric Company shall, in its next electric rate case filing, provide detail on compensation, performance targets, and achievement demonstrating whether adjustments should be made for the non-financial employee compensation incentive structure authorized for recovery in rates.

K. Within 60 days of the date of this order, DTE Electric Company shall file an application to amend Rate Schedule D1.9.

L. DTE Electric Company is directed to work with the Commission Staff to formulate reporting requirements for interconnection costs.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

____
Sally A. Talberg, Chairman

____
Norman J. Saari, Commissioner

By its action of May 2, 2019.

____
Kavita Kale, Executive Secretary

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

<u>RECUSAL OF COMMISSIONER DANIEL C. SCRIPPS</u>

(Submitted May 2, 2019)

I recuse myself from participation in this matter.

____
Daniel C. Scripps, Commissioner

DTE Electric Company
Case No. U-20162
Summary Present and Proposed Revenue by Rate Schedule

Total Revenues

Line No.	(a) Residential	(b) Total Present Revenue ($000's)	(c) Total Proposed Revenue ($000's)	(d) Total Net Increase/ (Decrease) ($000's)	(e) Total Net Increase/ (Decrease) (%)
1	D1/D1.6 Residential	$2,202,636	$2,308,647	$106,011	4.8%
2	D1.1 Int. Air	$44,397	$46,628	$2,231	5.0%
3	D1.2 TOD	$23,803	$24,060	$257	1.1%
4	D1.7 TOD	$11,151	$12,384	$1,233	11.1%
5	D1.8 Dynamic	$17,939	$18,814	$875	4.9%
6	D1.9 Elec. Vehicle	$504	$528	$24	4.7%
7	D2 Elec. Space Heat	$41,148	$43,129	$1,982	4.8%
8	D5 Res. Water Ht.	$14,698	$15,452	$754	5.1%
9	Total Residential	$2,356,276	$2,469,642	$113,366	4.8%
10					
11	**Secondary**				
12	D1.1 Int. Air	$702	$699	($3)	(0.4%)
13	D1.7 TOD	$679	$697	$18	2.7%
14	D1.8 Dynamic	$32	$32	($0)	(0.4%)
15	D 1.9 Elec Vehicle	$0	$0	$0	-
16	D3 Gen. Serv.	$931,380	$927,480	($3,901)	(0.4%)
17	D3.1 Unmetered	$8,469	$8,488	$19	0.2%
18	D3.2 Sec. Educ.	$27,980	$30,093	$2,113	7.6%
19	D3.3 Interruptible	$10,327	$10,284	($43)	(0.4%)
20	D4 Lg. Gen. Serv.	$244,392	$250,099	$5,706	2.3%
21	D5 Com. Wat. Ht.	$402	$413	$12	2.9%
22	E1.1 Eng. St. Ltg.	$932	$966	$34	3.7%
23	R7 Greenhs. Ltg.	$208	$215	$7	3.5%
24	R8 Space Cond.	$8,610	$8,575	($35)	(0.4%)
25	Total Secondary	$1,234,113	$1,238,042	$3,929	0.3%
26					
27	**Primary**				
28	D11 Prim. Supply	$969,915	$969,436	($479)	(0.0%)
29	D6.2 Pri. Educ.	$54,129	$58,728	$4,599	8.5%
30	D8 Int. Primary	$51,781	$49,697	($2,084)	(4.0%)
31	D10 El.Schools	$3,224	$2,963	($261)	(8.1%)
32	R1.1 Alt. Mtl. Melt.	$3,616	$3,540	($75)	(2.1%)
33	R1.2 El. Pr. Htg.	$32,933	$32,733	($200)	(0.6%)
34	R3 Standby	$9,029	$9,003	($27)	(0.3%)
35	R10 Int. Supply	$93,155	$95,132	$1,977	2.1%
36	Total Primary	$1,217,783	$1,221,232	$3,449	0.3%
37					
38	**Other**				
39	D9 Protective Ltg.	$7,388	$7,749	$361	4.9%
40	E1 Muni Street Ltg	$47,916	$51,755	$3,839	8.0%
41	E2 Traffic Lights	$4,383	$4,602	$219	5.0%
42	Total Other	$59,688	$64,106	$4,419	7.4%
43					
44	**Total All Classes**	$4,867,860	$4,993,023	$125,163	2.6%

Power Supply Revenues

Line No.	(a) Residential	(b) Power Supply Sales (MWH)	(c) Present Revenue ($000's)	(d) Increase/ (Decrease) ($000's)	(e) Proposed Revenue ($000's)	(f) Capacity Revenue ($000's)	(g) Non-Capacity Revenue ($000's)
1	D1/D1.6 Residential	13,765,328	$1,177,746	$49,428	$1,227,174	$581,998	$645,176
2	D1.1 Int. Air	321,293	$21,775	$914	$22,689	$10,761	$11,929
3	D1.2 TOD	161,650	$12,879	($406)	$12,473	$5,111	$7,362
4	D1.7 TOD	107,048	$5,377	$226	$5,602	$2,657	$2,945
5	D1.8 Dynamic	123,219	$8,823	$370	$9,193	$4,360	$4,833
6	D1.9 Elec. Vehicle	3,625	$282	$12	$293	$139	$154
7	D2 Elec. Space Heat	294,420	$19,788	$775	$20,562	$7,037	$13,525
8	D5 Res. Water Ht.	125,084	$5,736	$241	$5,977	$2,835	$3,142
9	Total Residential	14,901,667	$1,252,405	$51,559	$1,303,964	$614,897	$689,068
10							
11	**Secondary**						
12	D1.1 Int. Air	6,171	$425	($3)	$422	$175	$247
13	D1.7 TOD	9,266	$424	($3)	$421	$175	$246
14	D1.8 Dynamic	278	$21	($0)	$21	$9	$12
15	D1.9 Elec. Vehicle	0	$0	$0	$0	$0	$0
16	D3 Gen. Serv.	7,181,124	$573,915	($3,946)	$569,969	$236,769	$333,201
17	D3.1 Unmetered	76,768	$5,251	($36)	$5,215	$2,166	$3,048
18	D3.2 Sec. Educ.	197,953	$12,928	$703	$13,632	$4,552	$9,080
19	D3.3 Interruptible	94,451	$6,307	($43)	$6,263	$2,602	$3,661
20	D4 Lg. Gen. Serv.	2,173,074	$161,419	($2,071)	$159,348	$59,663	$99,685
21	D5 Com. Wat. Ht.	4,844	$228	($2)	$226	$94	$132
22	E1.1 Eng. St. Ltg.	9,804	$542	($4)	$538	$223	$315
23	R7 Greenhs. Ltg.	2,686	$123	($1)	$122	$51	$71
24	R8 Space Cond.	73,929	$5,179	($36)	$5,143	$2,136	$3,007
25	Total Secondary	9,830,349	$766,760	($5,441)	$761,319	$308,615	$452,705
26							
27	**Primary**						
28	D11 Prim. Supply	12,738,048	$841,301	$292	$841,593	$285,837	$555,755.79
29	D6.2 Pri. Educ.	608,689	$40,710	$4,437	$45,147	$17,528	$27,619
30	D8 Int. Primary	713,288	$43,205	($2,127)	$41,078	$9,391	$31,688
31	D10 El.Schools	27,326	$2,254	$1	$2,255	$764	$1,491
32	R1.1 Alt. Mtl. Melt.	55,770	$3,238	($85)	$3,152	$634	$2,518
33	R1.2 El. Pr. Htg.	464,927	$26,439	($661)	$25,778	$4,787	$20,992
34	R3 Standby	133,971	$6,280	($7)	$6,273	$1,319	$4,954
35	R10 Int. Supply	1,717,453	$86,194	$2,296	$88,490	$0	$88,489.96
36	Total Primary	16,459,473	$1,049,621	$4,146	$1,053,767	$320,260	$733,507
37							
38	**Other**						
39	D9 Protective Ltg.	28,974	$1,147	$169	$1,316	$0	$1,316
40	E1 Muni Street Ltg	150,090	$5,941	$878	$6,819	$0	$6,819
41	E2 Traffic Lights	56,023	$3,791	($299)	$3,492	$1,019	$2,473
42	Total Other	235,086	$10,879	$748	$11,627	$1,019	$10,608
43							
44	**Total All Classes**	41,426,576	$3,079,665	$51,012	$3,130,678	$1,244,791	$1,885,887

Distribution Revenues

Line No.	(a) Residential	(b) Distribution Sales (MWH)	(c) Present Revenue ($000's)	(d) Increase/ (Decrease) ($000's)	(e) Proposed Revenue ($000's)
1	D1/D1.6 Residential	13,765,328	$1,024,890	$56,583	$1,081,473
2	D1.1 Int. Air	321,293	$22,621	$1,317	$23,939
3	D1.2 TOD	161,650	$10,924	$663	$11,587
4	D1.7 TOD	107,048	$5,775	$1,007	$6,782
5	D1.8 Dynamic	123,219	$9,116	$505	$9,621
6	D1.9 Elec. Vehicle	3,625	$222	$12	$234
7	D2 Elec. Space Heat	294,420	$21,360	$1,207	$22,567
8	D5 Res. Water Ht.	125,084	$8,962	$513	$9,475
9	Total Residential	14,901,667	$1,103,871	$61,807	$1,165,677
10					
11	**Secondary**				
12	D1.1 Int. Air	6,171	$277	$0	$277
13	D1.7 TOD	9,427	$255	$21	$276
14	D1.8 Dynamic	278	$11	$0	$11
15	D1.9 Elec Vehicle	0	$0	$0	$0
16	D3 Gen. Serv.	7,498,396	$357,465	$45	$357,510
17	D3.1 Unmetered	76,768	$3,218	$55	$3,274
18	D3.2 Sec. Educ.	499,134	$15,052	$1,410	$16,462
19	D3.3 Interruptible	100,968	$4,020	$1	$4,021
20	D4 Lg. Gen. Serv.	2,506,151	$82,974	$7,777	$90,751
21	D5 Com. Wat. Ht.	4,850	$174	$13	$187
22	E1.1 Eng. St. Ltg.	9,804	$390	$38	$428
23	R7 Greenhs. Ltg.	2,686	$85	$8	$94
24	R8 Space Cond.	75,717	$3,431	$0	$3,432
25	Total Secondary	10,790,349	$467,353	$9,369	$476,723
26					
27	**Primary**				
28	D11 Prim. Supply	16,122,977	$128,615	($772)	$127,843
29	D6.2 Pri. Educ.	1,013,738	$13,419	$162	$13,581
30	D8 Int. Primary	845,260	$8,575	$43	$8,618
31	D10 El.Schools	36,675	$969	($261)	$708
32	R1.1 Alt. Mtl. Melt.	55,770	$378	$10	$388
33	R1.2 El. Pr. Htg.	473,628	$6,494	$461	$6,955
34	R3 Standby	127,822	$2,750	($20)	$2,729
35	R10 Int. Supply	1,717,453	$6,962	($319)	$6,642
36	Total Primary	20,393,323	$168,162	($697)	$167,465
37					
38	**Other**				
39	D9 Protective Ltg.	28,974	$6,241	$191	$6,433
40	E1 Muni Street Ltg	150,090	$41,976	$2,961	$44,937
41	E2 Traffic Lights	56,023	$592	$518	$1,110
42	Total Other	235,086	$48,809	$3,670	$52,479
43					
44	**Total All Classes**	46,320,426	$1,788,195	$74,150	$1,862,344

(Continued from Sheet No. C-17.00)

C4 APPLICATION OF RATES (Contd.)

C4.4 Choice of Rates (Contd.)

After the customer has selected the rate under which he elects to take service, the customer is not permitted to change from that rate to another until twelve months have elapsed. Neither will a customer be permitted to evade this rule by the device of temporarily terminating the customer's service.

However, the Company may, at its option, waive this rule where it appears that an earlier change is requested for permanent rather than for temporary or seasonal advantage. The intent of this rule is to prohibit frequent shifts from rate to rate. As used in this rule, the word rate shall include applicable riders.

C4.5 Billing for Service and Estimated Bills

A. Billing Frequency; Method of Delivery

(1) The Company shall transmit a bill once during each billing month to Residential Rate customers D1, and D2 in accordance with the approved daily rate schedules. The Company shall transmit a bill to customers by mail unless the Company and the customer agree in writing to another method of delivery.

(2) The Company shall transmit a bill once during each billing month to all other customers in accordance with the approved monthly rate schedules. The Company shall transmit a bill to customers by mail unless the Company and the customer agree in writing to another method of delivery.

B. Meter Reads

The Company shall schedule meters to be read on approximately a monthly basis and will attempt to read meters in accordance with such schedule. When the Company is unable to obtain an actual meter reading for any reason, the bill shall be estimated. Prior period(s) estimated bill(s) shall be adjusted as necessary when an actual meter reading is obtained.

C. Estimated Bills

When the Company is unable to obtain an actual meter reading, the bill shall be estimated on the basis of past service records, adjusted, as may be appropriate. Where past service records are not available or suitable for use, such billing shall be based upon whatever other service data are available. Each such account shall be adjusted as necessary each time an actual meter reading is obtained.

In the event that a customer's hourly usage data is not retrievable, such usage for the billing period shall be applied to the lowest hourly rate in the customer's current rate schedule, should the customer be on a time of use based rate.

Estimated bills shall have the same force and effect as those based upon actual meter readings.

(Continued on Sheet No. C-18.01)

(Continued from Sheet No. C-43.00)

C6 DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd.)

C6.5 Miscellaneous Customer Requests (Contd.)

(c) The facilities provide public service such as lighting, traffic signals, etc.

(3) If the Company's overhead or underground facilities are located on private property, the political subdivision must agree in advance to reimburse the Company for all expenses including overheads involved in relocating its facilities.

(4) When the Company is requested to relocate its facilities for reasons other than road improvements, payment may be required for the relocation from the firm, person or persons requesting the relocation***. Relocation or modification necessary to accommodate load additions or changes in service characteristics are governed by Rule C6., Distribution Systems, Line Extensions and Service Connections.*** Before actual relocation work is performed, the Company will estimate the cost of moving the facilities and an advance nonrefundable contribution in aid of construction in the amount of the estimate must be received from the firm, person or persons requesting such relocation. A contribution in aid of construction will not be required in instances where:

(a) The relocation is made for the convenience of the Company.

(b) The relocation is associated with other regularly scheduled conversion or construction work at the same location and can be done at the same time.

C6.6 Adjustment of Bills Because of Meter Errors

A If a meter creeps, if a metering installation is found upon any test to have an average error of more than 2.0%, if a demand metering installation is found upon any test to have an average error of more than 1.0% in addition to the errors allowed under B-6.6, or if a meter registration has been found to be in error due to apparent tampering by person or persons known or unknown, an adjustment of bills for service for the period of inaccuracy shall be made in the case of over-registration and may be made in the case of under- registration.

B The amount of the adjustment shall be calculated on the basis that the metering equipment should be 100% accurate with respect to the testing equipment used to make the test. For single-phase watthour meters, the average accuracy shall be the arithmetic average of the percent registration at light load and at heavy load, giving the heavy load registration a weight of 4 and the light load registration a weight of 1. For polyphase meters, the average accuracy shall be the arithmetic average of the percent registration at light load given a weight of 1 and at heavy load and 100% power factor given a weight of 4 and at heavy load and 50% lagging power factor given a weight of 2.

C If the date when the error in registration began can be determined, such date shall be the starting point for determination of the amount of the adjustment and shall be subject to subrule (l) of this rule.

(Continued on Sheet No. C-45.00)

M.P.S.C. No. 1 - Electric ______Revised Sheet No. C-66.00
DTE Electric Company Cancels______Revised Sheet No. C-66.00
(Final Order Case No. U-20162)

(Continued from Sheet No. C-65.00)

C9 SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE

C9.1 Nuclear Surcharge (NS)

On January 1987 MPSC Order authorized the establishment of an external trust fund to finance the decommissioning of Fermi 2 Power Plant when its operating license expires. The Order approves a decommissioning surcharge on customer bills under which the funds are collected. Pursuant to Commission Order U-10102 dated January 21, 1994, a revised surcharge became effective with service rendered on and after January 22, 1994. In the same order, the Commission authorized the establishment of an external fund to finance the disposal of low-level radioactive waste during the operating life of Fermi 2 Power Plant. Pursuant to an order in Case No. U-14399, costs associated with site security and radiation protection services were removed from base rates and transferred to the Nuclear Surcharge. Pursuant to Commission Order U-16472 dated October 20, 2011, a revised surcharge became effective with service rendered on and after October 29, 2011 Pursuant to Commission Order in Case No. U-17767 a revised surcharge became effective with service rendered on and after December 17, 2015**.** Pursuant to Commission Order in Case No. U-18255 a revised surcharge became effective with service rendered on and after April 18, 2018. ***Pursuant to Commission Order in Case No. U-20162 a revised surcharge became effective with service rendered on and after May __, 2019.***

C9.2 HOLD FOR FUTURE USE

C9.3 HOLD FOR FUTURE USE

C9.4 HOLD FOR FUTURE USE

Continued on Sheet No. C-67.00)

Issued ______, 2019 Effective for service rendered on

D. M. Stanczak and after ______, 2019
Vice President

Regulatory Affairs Issued under authority of the
Michigan Public Service Commission
Detroit, Michigan dated______, 2019

in Case No. U-20162

(Continued from Sheet No. C-68.00)

C9 SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE (Contd.)

C9.7.7 HOLD FOR FUTURE USE

C9.7.8 HOLD FOR FUTURE USE

C9.7.9 Low Income Energy Assistance Fund (LIEAF) Factor

On July 1, 2013, Public Act 95 of 2013 was signed into law, creating the Low Income Energy Assistance Fund (LIEAF). Money from the LIEAF will be distributed by the Department of Human Services as provided in the Michigan Energy Assistance Act, 2012 PA 615.

The Low Income Energy Assistance Fund (LIEAF) Factor is a monthly per meter charge for all customers receiving retail distribution service from a participating Michigan electric utility. DTE Electric Company is participating, and the LIEAF Factor effective beginning with the September 2017 billing month is $0.93. For residential customers, the LIEAF Factor will only apply to one meter per site.

C9.7.10 HOLD FOR FUTURE USE

C9.7.11 U-18014 Self- Implementation Refund (U-18014 SIR)

On September 15, 2017, the MPSC issued an Order in Case No. U-18344 approving the U-18014 Self-Implementation Refund (U-18014 SIR). This refund is a return of a portion of the revenue collected through the U-18014 Self- Implementation Surcharge (from August 1, 2016 through February 7, 2017) that exceeded the revenue increase approved by the MPSC on January 31, 2017 in Case No. U-18014, and the associated interest. The U-18014 SIR originally applied to bills rendered in the October, November and December 2017 billing cycles. To address the residual balance, a credit or surcharge will be applied to the rate schedules in section C9.8 in the April 2018 billing cycle. These factor apply on a per customer basis.

C9.7.12 Transitional Recovery Mechanism (TRM)

On October 25, 2017, the MPSC issued an Order in Case No. U-18251 authorizing the implementation of the Transitional Recovery Mechanism (TRM). This case is the annual reconciliation of the incremental revenues and costs associated with attaching former City of Detroit Public Lighting Department customers to DTE Electric's distribution system. The TRM surcharge of $0.001356 per kWh will be effective on a bills rendered basis for November 2017 through April 2018.

C9.7.13 U-18255 Implementation Surcharge (U-18255 IS)

Pursuant to Public Act 286 of 2008, Section 6a, electric utilities may implement up to the amount of their proposed annual rate increase prior to the MPSC issuing a final order. The Company self-implemented a rate increase of approximately $125 million to be collected from all customer classes, effective for service rendered on and after November 1, 2017. This surcharge terminated for service rendered on and after May 1, 2018.

(Continued on Sheet No. C-69.01)

M.P.S.C. No. 1 - Electric ____________Revised Sheet No. C-70.00
DTE Electric Company Cancels____________Revised Sheet No. C-70.00
(Final Order Case No. U-20162)

(Continued from Sheet No. C-69.01)

C9 SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE: (Contd.)

C9.8 Summary of Surcharges and Credits: Summary of surcharges and credits, pursuant to sub-rules C9.1, C9.2, C9.6, C9.7.9, C9.7.10, C9.7.11, C9.7.12 and C9.7.13. Cents per kilowatthour or percent of base bill, unless otherwise noted.

	NS ¢/kWh	EWRS ¢/kWh	Total Delivery Surcharges ¢/kWh	LIEAF Factor $/Billing Meter
Residential				
D1 Residential	***0.0827***	0.4322	***0.5149¢***	$0.93
D1.1 Int. Space Conditioning	***0.0827***	0.4322	***0.5149¢***	N/A
D1.2 Time of Day	***0.0827***	0.4322	***0.5149¢***	$0.93
D1.6 Special Low Income Pilot	***0.0827***	0.4322	***0.5149¢***	$0.93
D1.7 Geothermal Time-of-Day	***0.0827***	0.4322	***0.5149¢***	N/A
D1.8 Dynamic Peak Pricing	***0.0827***	0.4322	***0.5149¢***	$0.93
D1.9 Electric Vehicle	***0.0827***	0.4322	***0.5149¢***	N/A
D2 Space Heating	***0.0827***	0.4322	***0.5149¢***	$0.93
D5 Wtr Htg	***0.0827***	0.4322	***0.5149¢***	N/A
D9 Outdoor Lighting	***0.0827***	0.4322	***0.5149¢***	N/A
Commercial				
D1.1 Int. Space Conditioning	***0.0827***	See C9.6		$0.93
D1.7 Geothermal Time –of- day	***0.0827***	See C9.6		$0.93
D1.8 Dynamic Peak Pricing	***0.0827***	See C9.6		$0.93
D1.9 Electric Vehicle	***0.0827***	See C9.6		$0.93
D3 General Service	***0.0827***	See C9.6		$0.93
D3.1 Unmetered	***0.0827***	See C9.6		N/A
D3.2 Educ. Inst.	***0.0827***	See C9.6		$0.93
D3.3 Interruptible	***0.0827***	See C9.6		$0.93
D4 Large General Service	***0.0827***	See C9.6		$0.93
D5 Wtr Htg	***0.0827***	See C9.6		$0.93
D9 Outdoor Lighting	***0.0827***	See C9.6		$0.93
R3 Standby Secondary	***0.0827***	See C9.6		$0.93
R7 Greenhouse Lighting	***0.0827***	See C9.6		$0.93
R8 Space Conditioning	***0.0827***	See C9.6		$0.93
Industrial				
D6.2 Educ. Inst.	***0.0827***	See C9.6		$0.93
D8 Interruptible Primary	***0.0827***	See C9.6		$0.93
D10 Schools	***0.0827***	See C9.6		$0.93
D11 Primary Supply	***0.0827***	See C9.6		$0.93
R1.1 Metal Melting	***0.0827***	See C9.6		$0.93
R1.2 Electric Process Heating	***0.0827***	See C9.6		$0.93
R3 Standby Primary	***0.0827***	See C9.6		$0.93
R10 Interruptible Supply	***0.0827***	See C9.6		$0.93

(Continued on Sheet No. C-71.00)

(Continued from Sheet No. C-70.00)

C9 SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE: (Contd.)

C9.8 Summary of Surcharges and Credits (Contd.)**:**

	NS ¢/kWh	EWRS ¢/kWh	LIEAF Factor $/Billing Meter
Governmental			
E1	***0.0827***	See C9.6	N/A
E1.1 Energy	***0.0827***	See C9.6	$0.93
E2 Traffic	***0.0827***	See C9.6	N/A
Electric			
EC2 Secondary	***0.0827***	See C9.6	$0.93
EC2 Primary	***0.0827***	See C9.6	$0.93
EC2	***0.0827***	0.4322	$0.93

(Continued on Sheet No. C-72.00)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-20162)

________Revised Sheet No. D-1.00
Cancels________Revised Sheet No. D-1.00

RATE SCHEDULE NO. D1 **RESIDENTIAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service for all residential purposes through one meter to a single or double occupancy dwelling unit including farm dwellings. A dwelling unit consists of a kitchen, bathroom, and heating facilities connected on a permanent basis. Service to appurtenant buildings may be taken on the same meter.

This rate is not available for common areas of separately metered apartments and condominium complexes, nor to a separate meter which serves a garage, boat well or other non-dwelling applications.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER DAY:

Full Service Customers:

Power Supply Charges:
Capacity Energy Charges: ***3.705¢*** per kWh for the first 17 kWh per day
5.339¢ per kWh for excess over 17 kWh per day

Non-Capacity Energy Charge: ***4.687¢*** per kWh for all kWh

Delivery Charges:
Service Charge: $7.50 per month
Distribution Charge: ***6.109¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge.

Retail Access Service Customers:
Power Supply Charges for Retail Access Customers taking Utility Capacity service for DTE:
Capacity Energy Charges: ***3.705¢*** per kWh for the first 17 kWh per day
5.339¢ per kWh for excess over 17 kWh

Delivery Charges:
Service Charge: $7.50 per month
Distribution Charge: ***6.109¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Applies only to actual consumption and not to the minimum charge. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Sections C8.5.

(Continued on Sheet No. D-2.00)

Issued _________, 2019
D. M. Stanczak
Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after __________, 2019

Issued under authority of the
Michigan Public Service Commission
dated_____________, 2019
in Case No. U-20162

(Continued from Sheet No. D-1.00)

RATE SCHEDULE NO. D1 (Contd.) **RESIDENTIAL SERVICE RATE**

Former Rate D1.3 Full Service Customers:

Power Supply Charges:

Capacity Energy Charges:	***3.705¢*** per kWh for the first 17 kWh per day ***5.339¢*** per kWh for excess over 17 kWh per day
Non-Capacity energy Charge:	***4.687¢*** per kWh for all kWh

Delivery Charges:

Service Charge:	$7.50 per month
Distribution Charge:	***6.109¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge.

BILLING FREQUENCY: Based on a nominal 30-day month. See Section C4.5.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

LATE PAYMENT CHARGE: See Section C4.8.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.
Income Assistance Credit: $(7.50) per customer per month

(Continued on Sheet No. D-2.01)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-20162)

_________Revised Sheet No. D-4.00
Cancels_________Revised Sheet No. D-4.00

RATE SCHEDULE NO. D1.1 **INTERRUPTIBLE SPACE-CONDITIONING SERVICE RATE**

AVAILABILITY OF SERVICE: Available on an optional basis to Residential and Commercial customers desiring separately metered interruptible service for central air conditioning and/or central heat pump use. Customers who have more than one heat pump and/or air-conditioning unit which serves their business or home, will not be permitted to have only a portion of their load on the rate, all units will be interrupted upon the signal from the Company. Installations must conform with the Company's specifications. This rate is not available to commercial customers being billed on a demand rate.

HOURS OF SERVICE: 24 hours.

HOURS OF INTERRUPTION: Central air-conditioning and/or heat pump units only will be turned off by the Company by remote control on selected days for intervals of no longer than thirty minutes in any hour for no more than eight hours in any one day. Company interruptions may include interruptions for, but not limited to maintaining system integrity, making an emergency purchase, economic reasons, or when available system generation is insufficient to meet anticipated system load.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER MONTH: For separately metered space-conditioning service.

Full Service Customers:

Residential Power Supply Charges:

Capacity Energy Charge (June through October):	***3.525¢*** per kWh for all kWh
Capacity Energy Charge (November through May):	***0.874¢*** per kWh for all kWh
Non-Capacity Energy Charge***:***	***3.713¢*** per kWh for all kWh

Residential Delivery Charges:

Service Charge (June through October):	$1.95 per month
Distribution Charge (Year-round):	***6.109¢*** per kWh for all kWh

Commercial Power Supply Charges:

Capacity Energy Charge (June through October):	***3.685¢*** per kWh for all kWh
Capacity Energy Charge (November through May):	***0.885¢*** per kWh for all kWh
Non-Capacity Energy Charge***:***	***3.996¢*** per kWh for all kWh

Commercial Delivery Charges:

Service Charge (June through October):	$1.95 per month
Distribution Charge (Year-round):	***3.866¢*** per kWh for all kWh

(Continued on Sheet No. D-5.00)

(Continued from Sheet No. D-4.00)

RATE SCHEDULE NO. D1.1 (Contd.) **INTERRUPTIBLE SPACE-CONDITIONING SERVICE RATE**

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge.

Retail Access Service Customers:

Residential Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE***:***

Capacity Energy Charge (June through October):	***3.525¢*** per kWh for all kWh
Capacity Energy Charge (November through May***):***	***0.874¢*** per kWh for all kWh

Residential Delivery Charges:

Capacity Service Charge June through October):	$1.95 per month
Capacity Distribution Charge (Year-round):	***6.109¢*** per kWh for all kWh

Commercial Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through October):	***3.685¢*** per kWh for all kWh
Capacity Energy Charge (November through May***):***	***0.885¢*** per kWh for all kWh

Commercial Delivery Charges:

Service Charge June through October):	$1.95 per month
Distribution Charge (Year-round):	***3.866¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Applies only to actual consumption and not to the minimum charge. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' written notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

RATE SCHEDULE NO. D1.2 **RESIDENTIAL TIME-OF-DAY SERVICE RATE**

AVAILABILITY OF SERVICE: Available on an optional basis to customers who desire time of day service for their residential dwelling. Customers who select this rate must qualify for the Residential Service Rate D1.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:
Capacity Energy Charge (June through October):
12.375¢ per kWh for all On-peak kWh
1.145¢ per kWh for all Off-peak kWh

Capacity Energy Charge (November through May):
9.747¢ per kWh for all On-peak kWh
0.922¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.
Off-Peak Hours: All other kWh used.

Non-Capacity Energy Charge: ***4.554¢*** per kWh for all kWh

Delivery Charges:
Service Charge: $7.50 per month
Distribution Charge: ***6.109¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE***:***
Capacity Energy Charge (June through October):
12.375¢ per kWh for all On-peak kWh
1.145¢ per kWh for all Off-peak kWh

Capacity Energy Charge (November through May):
9.747¢ per kWh for all On-peak kWh
0.922¢ per kWh for all Off-peak kWh

On-Peak Hours: all kWh used between 1100 and 1900 hours Monday through Friday.
Off-Peak Hours: all other kWh used.

(Continued on Sheet No. D-7.00)

(Continued from Sheet No. D-6.00)

RATE SCHEDULE NO. D1.2 (Contd.) **RESIDENTIAL TIME-OF-DAY SERVICE RATE**

Delivery Charges:

Service Charge:	$7.50 per month
Distribution Charge:	***6.109¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C5.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Commencing upon installation of the Time-of-Day meter, service will be provided for twelve continuous months thereafter, with termination upon mutual consent of the Company and the customer.

WATER HEATING SERVICE: Water heating service is available on an optional basis.

INTERRUPTIBLE SPACE CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

RATE SCHEDULE NO. D1.6 **RESIDENTIAL SERVICE SPECIAL LOW INCOME PILOT RATE**

AVAILABILITY OF SERVICE: Customers who select this pilot rate must qualify for the Residential Service rate D1. To qualify for this pilot rate a customer must also provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. Service under this rate shall be limited to an annual average of 32,000 customers.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER DAY:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charges:	***3.705¢*** per kWh for the first 17 kWh per day
	5.339¢ per kWh for excess over 17 kWh per day
Non-Capacity Energy Charge*:*	***4.687¢*** per kWh for all kWh

Delivery Charges:

Service Charge:	$7.50 per month
Distribution Charge:	***6.109¢*** per kWh for all kWh
Special Low Income Discount:	($40.00) per month

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge.

Retail Access Service Customers:

Residential Power Supply Charges for Retail access Customers taking Utility Capacity Service from DTE*:*

Capacity Energy Charges*:*	***3.705¢*** per kWh for the first 17 kWh per day
	5.339¢ per kWh for excess over 17 kWh per day

(Continued on Sheet No. D-12.02)

(Continued from Sheet No. D-12.01)

RATE SCHEDULE NO. D1.6 (Contd.) RESIDENTIAL SERVICE SPECIAL LOW INCOME PILOT RATE

Delivery Charges:

Service Charge:	$7.50 per month
Distribution Charge:	***6.109¢*** per kWh for all kWh
Special Low Income Discount:	($40.00) per month

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

BILLING FREQUENCY: Based on a nominal 30-day month. See Section C4.5.

CONTRACT TERM: Open order, terminable on three days' notice by either party. If a customer fails to make the required payment on time for three consecutive billing periods that customer shall automatically be removed from this rate. Where special services are required, the term will be as specified in the applicable contract rider.

LATE PAYMENT CHARGE: See Section C4.8.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

RATE SCHEDULE NO. D1.7 **GEOTHERMAL TIME-OF-DAY RATE**

AVAILABILITY OF SERVICE: Available on an optional basis to residential customers desiring separately metered service for approved geothermal space conditioning and/or water heating. To qualify for the rate the water heater must be for sanitary purposes with the tank size, design and method of installation approved by the company. The space conditioning equipment must be permanently installed.

HOURS OF SERVICE: 24 Hours

CURRENT, PHASE AND VOLTAGE: Same as D1 and D3 Rates

CONTRACT TERM: The customer shall contract to remain on this rate for at least 12 months terminable on three days notice after the initial 12 months by either party. Where special services are required, the term will be specified on the applicable contract rider.

INSULATION STANDARDS FOR ELECTRIC HEATING: See Section C4.9.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

LATE PAYMENT CHARGE: See Section C4.8.

RATE PER DAY:

Full Service Customers:

Residential Power Supply Charges:

Capacity Energy Charge (June through September):

10.671¢ per kWh for all On-peak kWh
1.694¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):

3.048¢ per kWh for all On-peak kWh
1.805¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.
Off-Peak Hours: All other kWh used.

Non-Capacity Energy Charge*:* ***2.751¢*** per kWh for all kWh

Residential Delivery Charges:

Service Charge: 6.70¢ per day
Distribution Charge: ***5.644¢*** per kWh for all kWh

(Continued on Sheet No. D-13.01)

(Continued from Sheet No. D-13.00)

RATE SCHEDULE NO. D1.7 (Contd.) **GEOTHERMAL TIME-OF-DAY RATE**

Commercial Power Supply Charges:

Capacity Energy Charge (June through September):
2.916¢ per kWh for all On-peak kWh
1.516¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):
1.866¢ per kWh for all On-peak kWh
1.866¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.
Off-Peak Hours: All other kWh used.

Non-Capacity energy Charge*:* ***2.654¢*** per kWh for all kWh

Commercial Delivery Charges:

Service Charge: 6.70¢ per day
Distribution Charge: ***2.565¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Residential Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through September):
10.671¢ per kWh for all On-peak kWh
1.694¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):
3.048¢ per kWh for all On-peak kWh
1.805¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.
Off-Peak Hours: All other kWh used.

Residential Delivery Charges:

Service Charge: 6.70¢ per day
Distribution Charge: ***5.644¢*** per kWh for all kWh

Commercial Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through September):
2.916¢ per kWh for all On-peak kWh
1.516¢ per kWh for all Off-peak kWh

(Continued on Sheet No. D-13.02)

(Continued from Sheet No. D-13.01)

RATE SCHEDULE NO. D1.7 (Contd.) **GEOTHERMAL TIME-OF-DAY RATE**

Capacity Energy Charge (October through May):
1.866¢ per kWh for all On-peak kWh
1.866¢ per kWh for all Off-peak kWh

Commercial Delivery Charges:
Service Charge: 6.70¢ per day
Distribution Charge: ***2.565¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the commission. See Section C5.8.

RATE SCHEDULE NO. D1.8 **DYNAMIC PEAK PRICINGRATE**

AVAILABILITY OF SERVICE: Available on an optional basis to full-service residential and secondary commercial and industrial customers seeking to manage their electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. Service under this rate is limited to a residential customers and secondary commercial and industrial customers who have Advanced Metering Infrastructure installed. Service under this rate may not be combined with any other tariff, rider, or separately metered service.

The rate features three price tiers for On-Peak, Mid-Peak, and Off-Peak, as well as Critical Peak prices for days where Critical Hours are announced.

Definitions:

On-Peak Hours:	All kWh used between 3P.M. and 7P.M. Monday through Friday, excluding holidays
Mid-Peak Hours:	All kWh used between 7A.M. and 3P.M., and between 7P.M. and 11P.M., Monday through Friday excluding holidays
Off-Peak Hours:	All kWh used between 11 P.M and 7 A.M. Monday through Friday, and all weekend and holiday hours.
Critical-Peak Hours:	All kWh used during critical hours, which, when announced, will replace the full on-peak time period from 3 P.M. to 7 P.M.

The Company expects to implement Critical Peak pricing for no more than ***56*** hours per year, for evaluation of the tariff based on several factors including but not limited to economics, system demand or capacity deficiency.

Customers will be notified by 6 P.M. the day before critical hours are expected to occur. Notification will be made by one or more of the following methods: automated telephone message, text message, e-mail, or presentment on an in-premise display unit furnished by the Company. Receipt of such notice is the responsibility of the participating customer.

Customers who qualify and sign up for this rate agree to participate in evaluation surveys and will remain anonymous on all such surveys.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volt, single-phase three-wire; or 208Y/120 volts, three-phase four wire service may be taken.

(Continued on Sheet No. D-14.01)

(Continued from Sheet No. D-14.01)

RATE SCHEDULE NO. D1.8 (Contd.) **DYNAMIC PEAK PRICING RATE**

CHARGES:

Full Service Residential Customers:

Power Supply Charges:

Capacity Energy Charges:	***10.900¢*** per kWh for all On-Peak kWh
	4.724¢ per kWh for all Mid-Peak kWh
	1.019¢ per kWh for all Off-Peak kWh
	$0.91078 per kWh for all kWh during Critical Peak Hours
Non-Capacity Energy Charge:	***3.922¢*** per kWh for all kWh

Delivery Charges:

Service Charge:	$7.50 per month
Distribution Charge:	***6.109¢*** per kWh for all kWh

Full Service Secondary Commercial and Industrial Customers:

Power Supply Charges:

Capacity Energy Charges:	***10.139¢*** per kWh for all On-Peak kWh
	4.139¢ per kWh for all Mid-Peak kWh
	0.639¢ per kWh for all Off-Peak kWh
	$0.85696 per kWh for all kWh during Critical Peak Hours
Non-Capacity Energy Charge:	***4.373¢*** per kWh for all kWh

Delivery Charges:

Service Charge:	$11.25 per month
Distribution Charge:	***3.866¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

SCHEDULE OF HOLIDAYS: See Section C11

CONTRACT TERM: The customer shall contract to remain on this rate for at least 12 months terminable on three days' notice after the initial 12 months by either party.

LATE PAYMENT CHARGE: See Section C4.8.

RATE SCHEDULE NO. D1.9 **EXPERIMENTAL ELECTRIC VEHICLE RATE**

AVAILABILITY OF SERVICE: Available on an optional basis to residential and commercial customers desiring separately metered service for the sole purpose of charging licensed electric vehicles. Installations must conform to the Company's specifications. Service under this tariff is limited to 5,000 customers. Service on this rate is limited to electric vehicles that are SAE J1772 compliant, and all vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this rate. Low-speed electric vehicles including golf carts are not eligible to take service under this rate even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for the program.

HOURS OF SERVICE: 24 Hours

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at ***120/***240 volts, three wire. In certain city districts, alternating current is supplied from a Y connected secondary network from which ***120/***208 volts, three-wire service may be taken

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified on the applicable contract rider.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

LATE PAYMENT CHARGE: See Section C4.8.

OPTION 1: TIME OF DAY PRICING

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge:
8.023¢ per kWh for all On-peak kWh
2.006¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge***:***
8.895¢ per kWh for all On-peak kWh
2.223¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 9 am and 11 pm Monday through Friday.
Off-Peak Hours: All other kWh used.

Delivery Charges:

Service Charge: $1.95 per month
Distribution Charge: ***6.109¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge:
8.023¢ per kWh for all On-peak kWh
2.006¢ per kWh for all Off-peak kWh

(Continued on Sheet No. D-14.04)

(Continued from Sheet No. D-14.03)

RATE SCHEDULE NO. D1.9 (Contd.) **EXPERIMENTAL ELECTRIC VEHICLE RATE**

Retail Access Service Customer (Contd.):

On-Peak Hours: All kWh used between 9 am and 11 pm Monday through Friday.
Off-Peak Hours: All other kWh used.

Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***6.109¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See C8.5.

OPTION 2: MONTHLY FLAT FEE (Residential only*; closed to new customers as of May 31, 2019. Existing customers will be moved to a new rate by December 31, 2019*): Monthly Fee: ***$48.34*** per month per vehicle.

Surcharges and Credits: Included in monthly flat fee.

The monthly flat-fee option shall be limited to 250 customers.

SPECIAL TERMS AND CONDITIONS:

Service under this rate must be supplied through a separately metered circuit and approved electric vehicle charging equipment. Installations must conform with the Company's specifications.

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-20162)

________Revised Sheet No. D-15.00
Cancels________Revised Sheet No. D-15.00

RATE SCHEDULE NO. D2 **RESIDENTIAL SPACE HEATING RATE**

AVAILABILITY OF SERVICE: Available on an optional basis to customers desiring service for all residential purposes to a single or double occupancy dwelling unit including farm dwellings. All of the space heating must be total electric installed on a permanent basis and served through one meter. This rate also available to customers with add-on heat pumps and fossil fuel furnaces served on this rate prior to July 16, 1985. The design and method of installation and control of equipment as adopted to this service are subject to approval by the Company. This rate is also available to customers with electric heat assisted with a renewable heat source.

This rate is available only to dwellings being served on this rate prior to December 17, 2015.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally. In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volt three-wire service may be taken.

RATE PER DAY:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charges: (June through October):	***3.798¢*** per kWh for the first 17 kWh per day
	5.432¢ per kWh for over 17 kWh per day
Capacity Energy Charges: (November through May):	***2.241¢*** per kWh for the first 20 kWh per day
	0.875¢ per kWh for over 20 kWh per day
Non-Capacity energy Charge*:*	***4.594¢*** per kWh for all kWh

Delivery Charges:

Service Charge	$7.50 per month
Distribution Charge: (June through October):	***6.109¢*** per kWh for all kWh
Distribution Charge: (November through May):	***6.109¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge

Retail Access Service customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charges: (June through October):	***3.798¢*** per kWh for the first 17 kWh per day
	5.432¢ per kWh for over 17 kWh per day
Capacity Energy Charges: (November through May):	***2.241¢*** per kWh for the first 20 kWh per day
	0.875¢ per kWh for over 20 kWh per day

(Continued on Sheet No. D-16.00)

Issued __________, 2019
D. M. Stanczak
Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after __________, 2019

Issued under authority of the
Michigan Public Service Commission
dated____________, 2019
in Case No. U-20162

(Continued from Sheet No. D-15.00)

RATE SCHEDULE NO. D2 (Contd.) **RESIDENTIAL SPACE HEATING RATE**

Delivery Charges:

Service Charge	$7.50 per month
Distribution Charge: (June through October):	***6.109¢*** per kWh for all kWh
Distribution Charge: (November through May):	***6.109¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Applies only to actual consumption and not to the minimum charge. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

BILLING FREQUENCY: Based on a nominal 30-day month. See Section C4.5.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

LATE PAYMENT CHARGE: See Section C4.8.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

INSULATION STANDARDS FOR ELECTRIC HEATING: See Section C4.9.

RATE SCHEDULE NO. D3 **GENERAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service for any purpose, except that this rate is not available for service in conjunction with the Large General Service Rate. At the Company's option, service may be available to loads in excess of 1000 kW for situations where significant modifications to service facilities are not required to serve the excess load. ***The 1000 kW discretionary demand restriction does not apply to service provided to Electric Vehicle Fast-Charging Stations until June 1, 2024***. Effective May 27, 1981, this rate is not available to customers desiring service through one meter for residential purposes to a single or double occupancy dwelling unit.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:
Capacity Energy Charge: ***3.297¢*** per kWh for all kWh
Non-Capacity Energy Charge***:*** ***4.640¢*** per kWh for all kWh

Delivery Charges:
Service Charge: $11.25 per month
Distribution Charge: ***3.866¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:
Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE***:***
Capacity Energy Charge***:*** ***3.297¢*** per kWh for all kWh

Delivery Charges:
Service Charge: $11.25 per month
Distribution Charge: ***3.866¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

(Continued on Sheet No. D-19.00)

RATE SCHEDULE NO. D3.1 **UNMETERED GENERAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available at the option of the Company to customers for loads that can be readily calculated and are impractical to meter.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

SERVICE CONNECTIONS: The customer is to furnish and maintain all necessary wiring and equipment, or reimburse the Company therefore. Connections are to be brought to the Company's underground or overhead lines by the customer as directed by the Company, and the final connections to the Company's line are to be made by the Company.

Conversion and/or relocation of existing facilities must be paid for by the customer, except when initiated by the Company. The detailed provisions and schedule of such charges will be quoted upon request.

RATE: Capacity charge of ***2.822¢*** and non-capacity charge of ***7.837¢*** both applied per month per kilowatt hour of the total connected load in service for each customer. Loads operated cyclically will be prorated. This rate is based on 350 hours per month. Proration of cyclical loads will not apply when hours of operation are within 10% of base. Proration may either increase or decrease connected load.

The Company may, at its option, install meters and apply a standard metered rate schedule applicable to the service.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: $3.00 per month.

CONTRACT TERM: Open order on a month-to-month basis.

M.P.S.C. No. 1 - Electric ________Revised Sheet No. D-20.01
DTE Electric Company Cancels________Revised Sheet No. D-20.01
(Final Order Case No. U-20162)

RATE SCHEDULE NO. D3.2 **SECONDARY EDUCATIONAL INSTITUTION RATE**

AVAILABILITY OF SERVICE: Available to Educational Institution (school, college, university) customer locations desiring service at secondary voltage. School shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational training, or occupational school. "College" or "University" shall mean buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge:	***2.300¢*** per kWh for all kWh
Non-Capacity Energy Charge***:***	***4.587¢*** per kWh for all kWh

Delivery Charges:

Service Charge:	$11.25 per month
Distribution Charge:	***3.108¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge:	***2.300¢*** per kWh for all kWh

Delivery Charges:

Service Charge:	$11.25 per month
Distribution Charge:	***3.108¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the approved commission. See section C8.5.

LATE PAYMENT CHARGE: See Section C4.9.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

(Continued on Sheet No. D-20.02)

Issued __________, 2019 Effective for service rendered on
D. M. Stanczak and after ________, 2019
Vice President
Regulatory Affairs Issued under authority of the
Michigan Public Service Commission
Detroit, Michigan dated__________, 2019
in Case No. U-20162

RATE SCHEDULE NO. D3.3 **INTERRUPTIBLE GENERAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available to no more than 300 customers desiring interruptible service in conjunction with service taken under the general service rate. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company. Service to interruptible load may not be transferred to firm service circuits to avoid interruption. At the Company's option, in lieu of the requirement for separately metered circuits and associated interrupted equipment the customer may elect to have interval demand metering installed in order to monitor compliance when called to interrupt load. Customers electing this option will pay a $25.00 per month service charge instead of the normal $11.25 per month service charge. This rate is not available for loads that are primarily off-peak, such as outdoor lighting.

HOURS OF SERVICE: 24 hours except as described below.

HOURS OF INTERRUPTION: All electric power delivered hereunder shall be subject to interruption by the Company, by remote control signal. Company interruptions may include interruptions for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when available system generation is insufficient to meet anticipated system load.

NON-INTERRUPTION PENALTY: A customer who does not interrupt within one hour following a system integrity interruption order shall be billed at the rate of $50 per kW for the highest 30-minute kW demand created during the interruption period for all usage above the customer's firm demand, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount by which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge:	***2.755¢*** per kWh for all kWh
Non-Capacity Energy Charge***:***	***3.876¢*** per kWh for all kWh

Delivery Charges:

Service Charge:	$11.25 per month
Distribution Charge:	***3.866¢*** per kWh for all kWh

(Continued on Sheet No. D-22.00)

(Continued from Sheet No. D-21.00)

RATE SCHEDULE NO. D3.3 (Contd.) **INTERRUPTIBLE GENERAL SERVICE RATE**

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:
Capacity Energy Charge***:*** ***2.755¢*** per kWh for all kWh

Delivery Charges:
Service Charge: $11.25 per month
Distribution Charge: ***3.866¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' written notice by either party. However, where special services are required or where the investment to serve is out of proportion to the revenue derived there from, the contract term will be as specified in the applicable contract rider or Extension of Service Agreement.

RATE SCHEDULE NO. D4 **LARGE GENERAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service for any purpose, except that this rate is not available for service in conjunction with the General Service Rate.

Effective May 27, 1981, this rate is not available to customers desiring service through one meter for residential purposes to a single or double occupancy dwelling unit.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Demand Charge:	$***11.56*** per kW applied to the Monthly Billing Demand
Non-Capacity Demand Charges:	***$3.07*** per kW applied to the Monthly Billing Demand
Non-Capacity Energy Charges***:***	***4.384¢*** per kWh for the first 200 kWh per kW of billing demand ***3.384¢*** per kWh for the excess

Delivery Charges:

Service Charge:	$13.67 per month
Distribution Demand Charge:	$***14.25*** per kW applied to the Monthly Billing Demand

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Demand Charge:	$***11.56*** per kW applied to the Monthly Billing Demand

Delivery Charges:

Service Charge:	$13.67 per month
Distribution Demand Charge:	$***14.25*** per kW applied to the Monthly Billing Demand

(Continued on Sheet No. D-25.00)

RATE SCHEDULE NO. D5 **WATER HEATING SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers using hot water for sanitary purposes (other uses subject to the approval of the Company) and taking service under Residential and General Service Rate Schedules. This rate is also available to customers with solar assisted hot water heaters. Company approved waste heat reclamation systems and heat pump water heaters when used in conjunction with an approved electric water heater are also acceptable for use.

Available to customers who desire controlled water heating service to all of the heating elements of electric water heaters, the design and method of installation of which are approved by the Company as adapted to this service, taken through a separately metered circuit to which no other load except water heating may be connected.

HOURS OF SERVICE: The daily use of all controlled water heating service will be controlled by a timer or other monitoring device. Control of service shall not exceed 4 hours per day, said hours to be established from time to time by the Company.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 240 volts, three-wire, except that, in certain city districts, alternating current service at 208 volts, nominal, three-wire, or three-phase at the option of the Company.

RATE PER MONTH:

Full Service Customers:

Residential Power Supply Charges:	
Capacity Energy Charge:	***2.266¢*** per kWh for all kWh
Non-Capacity Energy Charge:	***2.512¢*** per kWh for all kWh
Residential Delivery Charges:	
Service Charge:	$1.95 per month
Distribution Charge:	***6.109¢*** per kWh for all kWh
Commercial Power Supply Charges:	
Capacity Energy Charge:	***1.941¢*** per kWh for all kWh
Non-Capacity Energy Charge:	***2.732¢*** per kWh for all kWh
Commercial Delivery Charges:	
Service Charge:	$1.95 per month
Distribution Charge:	***2.991¢*** per kWh for all kWh

Retail Access Service Customers:
Residential Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge*:*	***2.266¢*** per kWh for all kWh

(Continued on Sheet No. D-27.00)

(Continued from Sheet No. D-26.00)

RATE SCHEDULE NO. D5 (Contd.) **WATER HEATING SERVICE RATE**

Retail Access Service Customers (contd):
Residential Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE (contd):

Residential Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***6.109*¢** per kWh for all kWh

Commercial Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge: ***1.941¢*** *per kWh for all kWh*

Commercial Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***2.991*¢** per kWh for all kWh

SURCHARGES AND CREDITS: As approved by the Commission. Power Supply Charges are subject to Section C8.5. Delivery Charges are subject to Section C9.8**.** Capacity related surcharges and credits applicable topower supply, excluding PSCR, as approved by the Commission. see Section C8.5.

CONTRACT TERM: Open order, terminable or three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

WATER HEATER REQUIREMENTS FOR WATER HEATER RATE APPLICATION:

Rate Option	Minimum Tank Capacity*	Maximum Total Connected Load**
Residential	30 gallons	5.5 kW

Rate Option	Minimum Tank Capacity*	Maximum Total Connected Load**
Commercial	2 gallons per kW of total connected load 40 gallon minimum	Controlled by minimum tank capacity requirements

*No limitation to number of tanks
**Single or multi-element

RATE SCHEDULE NO. D6.2 **PRIMARY EDUCATIONAL INSTITUTION RATE**

AVAILABILITY OF SERVICE: Available to Educational Institution (school, college, university) customer locations desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50 kilowatts at a single location. School shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational training, or occupational school. "College" or "University" shall mean buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet normal maximum requirements but not less than 50 kilowatts. The Company undertakes to provide the necessary facilities for a supply of electric power from its primary distribution system at the contract capacity. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for customers served at more than one voltage level shall be the sum of the contract capacities established for each voltage level.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Demand Charge: $***13.11*** per kW of on-peak billing demand

Voltage Level Discount:

$0.55 per kW at transmission level

$0.82 per kW at subtransmission level

Non-Capacity

Energy Charges: ***4.826¢*** per kWh for all on-peak kWh
4.526¢ per kWh for all off-peak kWh

Voltage Level Discount:

0.258¢ per kWh at transmission level

0.153¢ per kWh at subtransmission level

Delivery Charges:

Primary Service Charge: ***$53.52*** per month

Subtransmission and Transmission Service Charge: $375 per month

Distribution Charges:

For primary service (less than 24 kV) $***4.07*** per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) $***1.46*** per kW of maximum demand. For service at transmission voltage (120 kV and above) $***0.65*** per kW of maximum demand.

(Continued on Sheet No. D-36.02)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-20162)

________Revised Sheet No. D-36.02
Cancels________Revised Sheet No. D-36.02

(Continued from Sheet No. D-36.01)

RATE SCHEDULE NO. D6.2 (Contd.) **PRIMARY EDUCATIONAL INSTITUTION RATE**

Full Service Customers (Contd):

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

Retail Access Service Customers:
Capacity (Only applicable to Retail Access Service Customers receiving utility Capacity Service from DTE Electric)

Demand Charge: $***13.11*** per kW of on-peak billing demand
Voltage Level Discount:
$0.82 per kW of on-peak billing demand at transmission level
$0.55 per kW of on-peak billing demand at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:

Primary Service Charge: ***$53.52*** per month
Subtransmission and Transmission Service Charge: $375 per month
Distribution Charges:
For primary service (less than 24 kV) $***4.07*** per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) $***1.46*** per kW of maximum demand. For service at transmission voltage (120 kV and above) $***0.65*** per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

LATE PAYMENT CHARGE: See Section C4.8.
DEFINITION OF CUSTOMER VOLTAGE LEVEL: See Section C13.

MONTHLY ON-PEAK BILLING DEMAND: The monthly on-peak billing demand shall be the single highest 30-minute integrated reading of the demand meter during the on-peak hours of the billing period. The monthly on-peak billing demand will not be less than 65% of the highest monthly on-peak metered billing demand during the billing months of June, July, August, September, and October of the preceding eleven billing months, nor less than 50 kilowatts.

MAXIMUM DEMAND: The maximum demand shall be the highest 30-minute demand created during the previous 12 billing months, including the current month but not less than 50% of contract capacity. This clause is applicable to each voltage level served.

(Continued on Sheet No. D-36.03)

Issued __________, 2019
D. M. Stanczak
Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after ___________, 2019

Issued under authority of the
Michigan Public Service Commission
dated___________, 2019
in Case No. U-20162

RATE SCHEDULE NO. D8 **INTERRUPTIBLE SUPPLY RATE**

AVAILABILITY OF SERVICE: Available to customers desiring separately metered service at primary voltage who contract for a specified quantity of demonstrated interruptible load of not less than 50 kilowatts at a single location. Contracted interruptible capacity on this rate is limited to 300 megawatts.

HOURS OF INTERRUPTION: All electric power delivered hereunder shall be subject to curtailment on order of the Company. Customers may be ordered to interrupt only when the Company finds it necessary to do so either to maintain system integrity or when the existence of such loads shall lead to a capacity deficiency by the utility. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3. A Capacity Deficiency Interruption Order may be given by the Company when available system generation is insufficient to meet anticipated system load.

NOTICE OF INTERRUPTION: The customer shall be provided, whenever possible, notice in advance of probable interruption and the estimated duration of the interruption.

NON-INTERRUPTION FEE: Customers who do not interrupt within one hour following notice of a capacity deficiency interruption order shall be billed at the cost of replacement energy plus 0.576¢ per kWh during the time of interruption plus the applicable voltage level charge, but not less than the normal D8 rate. Voltage level charges for service other than transmission voltage are:

0.201¢ per kWh at the distribution level.
0.082¢ per kWh at the subtransmission level.

NON-INTERRUPTION PENALTY: A customer who does not interrupt within one hour following a system integrity interruption order shall be billed at the rate of $50 per kW for the highest 30-minute kW demand created during the interruption period for all usage above the customer's firm demand, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount by which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet maximum interruptible requirements, but not less than 50 kilowatts. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The interruptible contract capacity shall not include any firm power capacity, except under Product Protection Provision.

(Continued on Sheet No. D-41.00)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-20162)

_________Revised Sheet No. D-41.00
Cancels_________Revised Sheet No. D-41.00

(Continued from Sheet No. D-40.00)

RATE SCHEDULE NO. D8 (Contd.) **INTERRUPTIBLE SUPPLY RATE**

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:
Capacity

Demand Charge: $***5.30*** per kW of on-peak billing demand
Voltage Level Discount***:***
$0.33 per kW of on-peak billing demand at transmission level
$0.22 per kW of on-peak billing demand at subtransmission level

Non-Capacity
Demand Charge***:*** ***$4.08*** per kW of on-peak billing demand
Voltage Level Discount:
$0.26 per kW of on-peak billing demand at transmission level
$0.17per kW of on-peak billing demand at subtransmission level
Energy Charge: ***4.339¢*** per kWh for all on-peak kWh
3.339¢ per kWh for all off-peak kWh

Voltage Level Discount:
0.201¢ per kWh at transmission level
0.119¢ per kWh at subtransmission level

Delivery Charges:
Primary Service Charge:$***53.52*** per month
Subtransmission and Transmission Service Charge: $375 per month
Distribution Charges:
For primary service (less than 24 kV) $***4.07*** per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) $***1.46*** per kW of maximum demand. For service at transmission voltage (120 kV and above) $***0.65*** per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

(Continued on Sheet No. D-42.00)

(Continued from Sheet No. D-41.00)

RATE SCHEDULE NO. D8 (Contd.) **INTERRUPTIBLE SUPPLY RATE**

Retail Access Service customers:

Capacity (only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Demand Charge: ***$5.30*** per kW of on-peak billing demand

Voltage Level Discount**:**

$0.33 per kW of on-peak billing demand at transmission level

$0.22 per kW of on-peak billing demand at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:

Primary Service Charge***:*** ***$53.52*** per month

Subtransmission and Transmission Service Charge: $375 per month

Distribution Charges:

For primary service (less than 24 kV) $***4.07*** per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) $***1.46*** per kW of maximum demand. For service at transmission voltage (120 kV and above) $***0.65*** per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of .040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

DEFINITION OF CUSTOMER VOLTAGE LEVEL: See Section C13.

MONTHLY ON-PEAK BILLING DEMAND: The monthly on-peak billing demand shall be the single highest 30-minute integrated reading of the demand meter during the on-peak hours of the billing period. In no event will the monthly on-peak billing demand be less than 65% of the highest monthly on-peak metered billing demand during the billing months of June, July, August, September, and October of the preceding eleven billing months, nor less than 50 kilowatts.

MAXIMUM DEMAND: The maximum demand shall be the highest 30-minute demand created during the previous 12 billing months, including the current month but not less than 50% of contract capacity. This clause is applicable to each voltage level served.

MINIMUM CHARGE: All applicable demand charges plus the service charge and any applicable per meter per month surcharges.

ON-PEAK HOURS: See Section C11.

(Continued on Sheet No. D-43.00)

(Continued from Sheet No. D-44.00)

RATE SCHEDULE NO. D9 (Contd.) **OUTDOOR PROTECTIVE LIGHTING**

(1) Special purpose facilities are considered to be line or cable extensions, transformers, and any additional poles without lights, excluding facilities provided under stated charges on Sheet No. D-45.00. Where special purpose facilities are required, a service charge of 18% per year on the investment in such facilities will be billed in installments as an addition to the regular rate for each light. In the event the customer discontinues service before the end of the contract term, the established rate as well as the service charge on special purpose facilities for the remaining portion of the contract term shall immediately become due and payable. This provision was closed to new installations as of January 22, 1994.

(2) For new installations after January 22, 1994, which require investment in excess of three times the annual revenue, this rate is available only to customers who make a contribution in aid of construction equal to the amount by which the investment exceeds three times the annual revenue at the prevailing rate at the time of installation.

(3) For new underground-fed installations of 5 lights or more after May 1, 2019, which require investment in excess of three times the annual revenue, the customer may elect to pay a post charge for each increment of $1,000 investment required above three times the annual revenue.

MONTHLY RATES: Overhead Outdoor Protective Lighting with Existing Pole and Existing Secondary Facilities ***(***All-night service***)***.

Power Supply Charges:

Capacity Energy Charge: 0.00¢ per kWh for all kWh
Non-Capacity Energy Charge: ***4.54***¢ per kWh for all kWh

Luminaire Charges:

(a) Nominal Lamp Size	(b) Type of Service	(c) Distribution Charge per Lamp per Month	(d) System Wattage	(e) Average Monthly Hours (4200/12)	(f) Energy Charge	(g) Average Energy Cost per Month (d*e*f/1000)	(h) Average Monthly Cost
100 W	Mercury Vapor	***$12.06***	120	350	***$0.0454***	***$1.91***	***$13.97***
175 W	Mercury Vapor	***$15.83***	210	350	***$0.0454***	***$3.34***	***$19.17***
250 W	Mercury Vapor	***$19.60***	300	350	***$0.0454***	***$4.77***	***$24.37***
400 W	Mercury Vapor	***$26.05***	450	350	***$0.0454***	***$7.16***	***$33.21***
1,000 W	Mercury Vapor	***$51.88***	1060	350	***$0.0454***	***$16.85***	***$68.73***
100 W	High Pressure Sodium	***$10.67***	135	350	***$0.0454***	***$2.15***	***$12.82***
150 W	High Pressure Sodium	***$12.57***	200	350	***$0.0454***	***$3.18***	***$15.75***
250 W	High Pressure Sodium	***$15.96***	305	350	***$0.0454***	***$4.85***	***$20.81***
400 W	High Pressure Sodium	***$20.99***	465	350	***$0.0454***	***$7.39***	***$28.39***
1,000 W	High Pressure Sodium	***$46.44***	1100	350	***$0.0454***	***$17.49***	***$63.93***
100 W	Metal Halide	***$13.63***	120	350	***$0.0454***	***$1.91***	***$15.54***
150 W	Metal Halide	***$15.89***	180	350	***$0.0454***	***$2.86***	***$18.76***
175 W	Metal Halide	***$17.03***	210	350	***$0.0454***	***$3.34***	***$20.37***
250 W	Metal Halide	***$20.42***	300	350	***$0.0454***	***$4.77***	***$25.19***
320 W	Metal Halide	***$23.59***	365	350	***$0.0454***	***$5.80***	***$29.39***
400 W	Metal Halide	***$27.21***	460	350	***$0.0454***	***$7.31***	***$34.53***
1,000 W	Metal Halide	***$57.51***	1050	350	***$0.0454***	***$16.70***	***$74.21***
20 - 29 W	LED	***$8.16***	25	350	***$0.0454***	***$0.40***	***$8.56***
30 - 39 W	LED	***$8.78***	35	350	***$0.0454***	***$0.56***	***$9.34***
40 - 49 W	LED	***$9.40***	45	350	***$0.0454***	***$0.72***	***$10.11***
50 - 59 W	LED	***$10.01***	55	350	***$0.0454***	***$0.87***	***$10.89***
60 - 69 W	LED	***$10.63***	65	350	***$0.0454***	***$1.03***	***$11.66***
70 - 79 W	LED	***$11.25***	75	350	***$0.0454***	***$1.19***	***$12.44***

(Continued on Sheet No. D-45.0 1)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-20162)

_________Revised Sheet No. D-45.01
Cancels_________Revised Sheet No. D-45.01

(Continued from Sheet No. D-45.00)

RATE SCHEDULE NO. D9 (Contd.) **OUTDOOR PROTECTIVE LIGHTING**

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
80 - 89 W	LED	*$11.98*	85	350	*$0.0454*	*$1.35*	*$13.33*
90 - 99 W	LED	*$12.71*	95	350	*$0.0454*	*$1.51*	*$14.22*
100 - 109 W	LED	*$13.44*	105	350	*$0.0454*	*$1.67*	*$15.11*
110 - 119 W	LED	*$14.17*	115	350	*$0.0454*	*$1.83*	*$16.00*
120 - 129 W	LED	*$14.90*	125	350	*$0.0454*	*$1.99*	*$16.89*
130 - 139 W	LED	*$15.63*	135	350	*$0.0454*	*$2.15*	*$17.78*
140 - 149 W	LED	*$16.21*	145	350	*$0.0454*	*$2.31*	*$18.51*
150 - 159 W	LED	*$16.78*	155	350	*$0.0454*	*$2.46*	*$19.25*
160 - 169 W	LED	*$17.36*	165	350	*$0.0454*	*$2.62*	*$19.98*
170 - 179 W	LED	*$17.93*	175	350	*$0.0454*	*$2.78*	*$20.72*
180 - 189 W	LED	*$18.51*	185	350	*$0.0454*	*$2.94*	*$21.45*
190 - 199 W	LED	*$19.08*	195	350	*$0.0454*	*$3.10*	*$22.19*
200 - 209 W	LED	*$19.66*	205	350	*$0.0454*	*$3.26*	*$22.92*
210 - 219 W	LED	*$20.24*	215	350	*$0.0454*	*$3.42*	*$23.65*
220 - 229 W	LED	*$20.84*	225	350	*$0.0454*	*$3.58*	*$24.41*
230 - 239 W	LED	*$21.44*	235	350	*$0.0454*	*$3.74*	*$25.17*
240 - 249 W	LED	*$22.04*	245	350	*$0.0454*	*$3.90*	*$25.93*
250 - 259 W	LED	*$22.64*	255	350	*$0.0454*	*$4.05*	*$26.69*
260 - 269 W	LED	*$23.24*	265	350	*$0.0454*	*$4.21*	*$27.45*
270 - 279 W	LED	*$23.84*	275	350	*$0.0454*	*$4.37*	*$28.21*
280 - 289 W	LED	*$24.44*	285	350	*$0.0454*	*$4.53*	*$28.97*
290 - 299 W	LED	*$25.00*	295	350	*$0.0454*	*$4.69*	*$29.69*
300 - 309 W	LED	*$25.55*	305	350	*$0.0454*	*$4.85*	*$30.40*
310 - 319 W	LED	*$26.11*	315	350	*$0.0454*	*$5.01*	*$31.12*
320 - 329 W	LED	*$26.67*	325	350	*$0.0454*	*$5.17*	*$31.83*
330 - 339 W	LED	*$27.22*	335	350	*$0.0454*	*$5.33*	*$32.55*
340 - 349 W	LED	*$27.78*	345	350	*$0.0454*	*$5.49*	*$33.26*
350 - 359 W	LED	*$28.33*	355	350	*$0.0454*	*$5.64*	*$33.98*
360 - 369 W	LED	*$28.89*	365	350	*$0.0454*	*$5.80*	*$34.69*
370 - 379 W	LED	*$29.45*	375	350	*$0.0454*	*$5.96*	*$35.41*
380 - 389 W	LED	*$30.00*	385	350	*$0.0454*	*$6.12*	*$36.12*
390 - 399 W	LED	*$30.56*	395	350	*$0.0454*	*$6.28*	*$36.84*

For installations prior to January 22, 1994. New Pole and Single Span of Secondary Facilities. The above rate plus $24.48 per pole per year.

Effective January 22, 1994 installation requiring additional facilities shall pay a contribution in aid of construction in lieu of the service charge. Contribution is described in paragraph (2) above.

Multiple Lamps on a Single Pole. For each additional luminaire added to the same pole the charge will be at the existing pole rate.

The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those fixtures fail. At that time, ***the luminaire will be converted to LED***.

(Continued on Sheet No. D-46.00)

Issued ___________, 2019

D. M. Stanczak
Vice President
Regulatory Affairs

Detroit, Michigan

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M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-20162)

_________Revised Sheet No. D-46.00
Cancels__________Revised Sheet No. D-46.00

(Continued from Sheet No. D-45.01)

RATE SCHEDULE NO. D9 (Contd.) **OUTDOOR PROTECTIVE LIGHTING**

MONTHLY RATES: Underground Outdoor Protective Lighting with Lamp Spacing up to 120 Feet of Trench (All-night service).

Power Supply Charges:
Capacity Energy Charge: 0.00¢ per kWh for all kWh
Non-Capacity Energy Charge: ***4.54***¢ per kWh for all kWh

Luminaire Charges:

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	Type of Service	Distribution Charge per Lamp per Month	System Wattage	Average Monthly Hours (4200/12)	Energy Charge	Average Energy Cost per Month (d*e*f/1000)	Average Monthly Cost
100 W	Mercury Vapor	***$30.32***	120	350	***$0.0454***	***$1.91***	***$32.23***
175 W	Mercury Vapor	***$32.57***	210	350	***$0.0454***	***$3.34***	***$35.91***
250 W	Mercury Vapor	***$35.71***	300	350	***$0.0454***	***$4.77***	***$40.48***
400 W	Mercury Vapor	***$41.06***	450	350	***$0.0454***	***$7.16***	***$48.22***
1,000 W	Mercury Vapor	***$66.41***	1060	350	***$0.0454***	***$16.85***	***$83.26***
70 W	***High Pressure Sodium***	***$27.23***	***95***	***350***	***$0.0454***	***$1.51***	***$28.74***
100 W	High Pressure Sodium	***$28.12***	135	350	***$0.0454***	***$2.15***	***$30.26***
150 W	High Pressure Sodium	***$29.60***	200	350	***$0.0454***	***$3.18***	***$32.78***
250 W	High Pressure Sodium	***$32.55***	305	350	***$0.0454***	***$4.85***	***$37.40***
400 W	High Pressure Sodium	***$36.77***	465	350	***$0.0454***	***$7.39***	***$44.16***
1,000 W	High Pressure Sodium	***$53.64***	1100	350	***$0.0454***	***$17.49***	***$71.13***
100 W	Metal Halide	***$28.12***	120	350	***$0.0454***	***$1.91***	***$30.03***
150 W	Metal Halide	***$29.60***	180	350	***$0.0454***	***$2.86***	***$32.46***
175 W	Metal Halide	***$30.33***	210	350	***$0.0454***	***$3.34***	***$33.67***
250 W	Metal Halide	***$32.55***	300	350	***$0.0454***	***$4.77***	***$37.32***
400 W	Metal Halide	***$36.77***	460	350	***$0.0454***	***$7.31***	***$44.08***
1,000 W	Metal Halide	***$53.64***	1050	350	***$0.0454***	***$16.70***	***$70.34***
20 - 29 W	LED	***$26.91***	25	350	***$0.0454***	***$0.40***	***$27.30***
30 - 39 W	LED	***$27.63***	35	350	***$0.0454***	***$0.56***	***$28.19***
40 - 49 W	LED	***$28.36***	45	350	***$0.0454***	***$0.72***	***$29.07***
50 - 59 W	LED	***$28.85***	55	350	***$0.0454***	***$0.87***	***$29.73***
60 - 69 W	LED	***$29.35***	65	350	***$0.0454***	***$1.03***	***$30.38***
70 - 79 W	LED	***$29.85***	75	350	***$0.0454***	***$1.19***	***$31.04***
80 - 89 W	LED	***$30.31***	85	350	***$0.0454***	***$1.35***	***$31.66***
90 - 99 W	LED	***$30.78***	95	350	***$0.0454***	***$1.51***	***$32.29***
100 - 109 W	LED	***$31.25***	105	350	***$0.0454***	***$1.67***	***$32.92***
110 - 119 W	LED	***$31.71***	115	350	***$0.0454***	***$1.83***	***$33.54***
120 - 129 W	LED	***$32.18***	125	350	***$0.0454***	***$1.99***	***$34.17***
130 - 139 W	LED	***$32.64***	135	350	***$0.0454***	***$2.15***	***$34.79***
140 - 149 W	LED	***$33.07***	145	350	***$0.0454***	***$2.31***	***$35.38***
150 - 159 W	LED	***$33.50***	155	350	***$0.0454***	***$2.46***	***$35.96***
160 - 169 W	LED	***$33.92***	165	350	***$0.0454***	***$2.62***	***$36.55***
170 - 179 W	LED	***$34.35***	175	350	***$0.0454***	***$2.78***	***$37.13***
180 - 189 W	LED	***$34.78***	185	350	***$0.0454***	***$2.94***	***$37.72***

(Continued on Sheet No. D-46.01)

Issued ___________, 2019
D. M. Stanczak
Vice President
Regulatory Affairs

Detroit, Michigan

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M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-20162)

__________Revised Sheet No. D-46.01
Cancels__________Revised Sheet No. D-46.01

(Continued from Sheet No. D-46.00)

RATE SCHEDULE NO. D9 (Contd.) **OUTDOOR PROTECTIVE LIGHTING**

Luminaire Charges(Contd):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
190 - 199 W	LED	***$35.20***	195	350	***$0.0454***	***$3.10***	***$38.30***
200 - 209 W	LED	***$35.63***	205	350	***$0.0454***	***$3.26***	***$38.89***
210 - 219 W	LED	***$36.05***	215	350	***$0.0454***	***$3.42***	***$39.47***
220 - 229 W	LED	***$36.48***	225	350	***$0.0454***	***$3.58***	***$40.06***
230 - 239 W	LED	***$36.91***	235	350	***$0.0454***	***$3.74***	***$40.64***
240 - 249 W	LED	***$37.33***	245	350	***$0.0454***	***$3.90***	***$41.23***
250 - 259 W	LED	***$37.76***	255	350	***$0.0454***	***$4.05***	***$41.81***
260 - 269 W	LED	***$38.19***	265	350	***$0.0454***	***$4.21***	***$42.40***
270 - 279 W	LED	***$38.61***	275	350	***$0.0454***	***$4.37***	***$42.98***
280 - 289 W	LED	***$39.04***	285	350	***$0.0454***	***$4.53***	***$43.57***
290 - 299 W	LED	***$39.46***	295	350	***$0.0454***	***$4.69***	***$44.15***
300 - 309 W	LED	***$39.89***	305	350	***$0.0454***	***$4.85***	***$44.74***
310 - 319 W	LED	***$40.32***	315	350	***$0.0454***	***$5.01***	***$45.32***
320 - 329 W	LED	***$40.74***	325	350	***$0.0454***	***$5.17***	***$45.91***
330 - 339 W	LED	***$41.17***	335	350	***$0.0454***	***$5.33***	***$46.50***
340 - 349 W	LED	***$41.59***	345	350	***$0.0454***	***$5.49***	***$47.08***
350 - 359 W	LED	***$42.02***	355	350	***$0.0454***	***$5.64***	***$47.67***
360 - 369 W	LED	***$42.45***	365	350	***$0.0454***	***$5.80***	***$48.25***
370 - 379 W	LED	***$42.87***	375	350	***$0.0454***	***$5.96***	***$48.84***
380 - 389 W	LED	***$43.30***	385	350	***$0.0454***	***$6.12***	***$49.42***
390 - 399 W	LED	***$43.73***	395	350	***$0.0454***	***$6.28***	***$50.01***

Effective January 22, 1994 installation requiring additional facilities shall pay a contribution in aid of construction in lieu of the service charge. Contribution is described in paragraph (2) above.

Effective May 1, 2019, installations requiring additional facilities shall pay a post charge of $6.68 per increment of $1,000 of expense in lieu of contribution in aid of construction. Contribution is described in paragraph (3) above.

Multiple Lamps on a Single Pole. For each additional luminaire added to the same pole reduce rate per lamp per year on the added luminaire by $97.92.

The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those luminaires fail. At that time, ***the luminaire will be converted to LED***.

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D. M. Stanczak
Vice President
Regulatory Affairs

Detroit, Michigan

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RATE SCHEDULE NO. D10 **ALL-ELECTRIC SCHOOL BUILDING SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service in school buildings served at primary voltage who contract for a specified installed capacity of not less than 50 kilowatts at a single location provided the space heating and water heating for all or a substantial portion of the premises is supplied by electric service and is installed on a permanent basis.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800 or 13,200 volts at the option of the Company.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Energy Charge (June through October):	***3.985¢*** per kWh for all kWh
Energy Charge (November through May):	***2.184¢*** per kWh for all kWh

Non-Capacity

Energy Charge (June through October):	***5.458¢*** per kWh for all kWh
Energy Charge (November through May):	***5.458¢*** per kWh for all kWh

Delivery Charges:

Service Charge:	***$53.52*** per month
Distribution Charge:	***1.488¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Energy Charge (June through October):	***3.985¢*** per kWh for all kWh
Energy Charge (November through May):	***2.184¢*** per kWh for all kWh

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:

Service Charge:	***$53.52*** per month
Distribution Charge:	***1.488¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8.

(Continued on Sheet No. D-48.00)

M.P.S.C. No. 1 - Electric ______Revised Sheet No. D-48.01
DTE Electric Company Cancels_______Revised Sheet No. D-48.01
(Final Order Case No. U-20162)

RATE SCHEDULE NO. D11 **PRIMARY SUPPLY RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50 kilowatts at a single location.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet normal maximum requirements but not less than 50 kilowatts. The Company undertakes to provide the necessary facilities for a supply of electric power from its primary distribution system at the contract capacity. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for customers served at more than one voltage level shall be the sum of the contract capacities established for each voltage level.

RATE PER MONTH:
Full Service Customers:
Power Supply Charges:
Capacity
Demand Charge: ***$12.33*** per kW of on-peak billing demand
Voltage Level Discount:
$0.78 per kW of on-peak billing demand at transmission level
$0.52 per kW of on-peak billing demand at subtransmission level

Non-Capacity
Demand Charge***:*** ***$4.68*** per kW of on-peak billing demand
Voltage Level Discount:
$0.29 per kW of on-peak billing demand at transmission level
$0.20 per kW of on-peak billing demand at subtransmission level
Energy Charge: ***4.339¢*** per kWh for all on-peak kWh
3.339¢ per kWh for all off-peak kWh

Voltage Level Discount:
0.201¢ per kWh at transmission level
0.119¢ per kWh at subtransmission level

Delivery Charges:
Primary Service Charge: ***$53.52*** per month
Subtransmission and Transmission Service Charge: $375 per month

Distribution Charges:
For primary service (less than 24 kV) ***$4.07*** per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) ***$1.46*** per kW of maximum demand. For service at transmission voltage (120 kV and above) ***$0.65*** per kW of maximum demand.

Continued on Sheet No. D-48.02)

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D. M. Stanczak and after ___________, 2019
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Regulatory Affairs Issued under authority of the
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(Continued from Sheet No. D-48.01)

RATE SCHEDULE NO. D11 (Contd.) **PRIMARY SUPPLY RATE**

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:
Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Demand Charge: ***$12.33*** per kW of on-peak billing demand
Voltage Level Discount:
$0.78 per kW of on-peak billing demand at transmission level
$0.52 per kW of on-peak billing demand at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C5.8.

Delivery Charges:

Primary Service Charge:	***$53.52*** per month
Subtrassmission and Transmission Service Charge:	$375 per month

Distribution Charges:
For primary service (less than 24 kV) ***$4.07*** per kW of maximum demand**.**
For service at subtransmission voltage (24 to 41.6 kV) ***$1.46*** per kW of maximum demand. For service at transmission voltage (120 kV and above) ***$0.65*** per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

DEFINITION OF CUSTOMER VOLTAGE LEVEL: See Section C13.

MONTHLY ON-PEAK BILLING DEMAND: The monthly on-peak billing demand shall be the single highest 30-minute integrated reading of the demand meter during the on-peak hours of the billing period. The monthly on- peak billing demand will not be less than 65% of the highest monthly on-peak metered billing demand during

(Continued on Sheet No. D-48.03)

(Continued from Sheet No. D-49.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

CONTRACT TERM: Minimum 5 year term. Upon expiration of the initial term shall continue on a month-to-month basis until terminated by mutual written consent of the parties or by either party with thirty (30) days prior written notice to the other party. Any conversion, relocation and/or removal of existing street lighting facilities at the customer's request, including those removals necessitated by termination of service, must be paid for by the customer. The detailed provisions and schedule of charges, which may include the remaining value of the existing facilities, will be quoted upon request. The Company shall not withdraw service, and the municipality shall not substitute another source of service in whole or in part, without twelve months' written notice to the other party.

Option I: Company Owned Street Lighting System

Where new installations require an investment in excess of an investment allowance, Option I is available only to customers who make a contribution in aid of construction equal to the amount by which the investment exceeds three times the annual revenue at the prevailing rate at the time of installation. (Effective January 1, 1991, the investment amount will be limited to direct cost. Effective January 1, 1992, the investment amount will include full cost.)

As an alternative, where the required contribution exceeds $10,000, upon agreement of the customer and the Company, the customer will pay an additional annual charge of the Company's weighted average cost of capital (***6.81***%) times the contribution amount in lieu of the cash contribution.

For new underground-fed installations of 5 lights or more after May 1, 2019, which require investment in excess of three times the annual revenue at the prevailing rate at the time of installation, the customer may elect to pay a post charge for each increment of $1,000 investment required above three times the annual revenue.

DE-ENERGIZED LIGHTS: Customers may elect to have any or all luminaires served under this rate disconnected. The charge per luminaire per year, payable in equal monthly installments, shall be 60% of the regular yearly rates. A *$35.00* charge per luminaire will be made at the time of de-energization and at the time of re-energization.

DUSK TO MIDNIGHT SERVICE: For service to parking lots from dusk to approximately twelve o'clock midnight E.S.T., a discount of 1.060¢ per nominal lamp size wattage per month will be applied. One control per circuit will be provided.

EXPERIMENTAL PROGRAMMABLE PHOTOCELL SERVICE: Customers may elect to place luminaires on photocells that are programmable to turn off lights at pre-determined times during the night. A discount of 1.060¢ per nominal lamp size wattage per month will be applied.

MONTHLY RATES OPTION I: Overhead Municipal Street Lighting *(*All-night service*)*.

Power Supply Charges:
Capacity Energy Charge: 0.00¢ per kWh for all kWh
Non-Capacity Energy Charge: ***4.54***¢ per kWh for all kWh

(Continued on Sheet No. D-50.01)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-20162)

________Revised Sheet No. D-50.01
Cancels________Revised Sheet No. D-50.01

(Continued from Sheet No. D-50.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Luminaire Charges:

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
100 W	Mercury Vapor	$17.30	120	350	$0.0454	$1.91	$19.21
175 W	Mercury Vapor	$21.09	210	350	$0.0454	$3.34	$24.43
250 W	Mercury Vapor	$25.00	300	350	$0.0454	$4.77	$29.77
400 W	Mercury Vapor	$32.77	450	350	$0.0454	$7.16	$39.92
1,000 W	Mercury Vapor	$64.32	1060	350	$0.0454	$16.85	$81.17
70 W	High Pressure Sodium	$12.84	95	350	$0.0454	$1.51	$14.35
100 W	High Pressure Sodium	$14.53	135	350	$0.0454	$2.15	$16.67
150 W	High Pressure Sodium	$17.27	200	350	$0.0454	$3.18	$20.45
250 W	High Pressure Sodium	$22.22	305	350	$0.0454	$4.85	$27.07
360 W	High Pressure Sodium	$27.57	418	350	$0.0454	$6.65	$34.22
400 W	High Pressure Sodium	$29.55	465	350	$0.0454	$7.39	$36.94
1,000 W	High Pressure Sodium	$58.10	1100	350	$0.0454	$17.49	$75.59
70 W	Metal Halide	$16.87	85	350	$0.0454	$1.35	$18.22
100 W	Metal Halide	$18.34	120	350	$0.0454	$1.91	$20.25
150 W	Metal Halide	$20.87	180	350	$0.0454	$2.86	$23.74
175 W	Metal Halide	$22.14	210	350	$0.0454	$3.34	$25.48
250 W	Metal Halide	$27.35	300	350	$0.0454	$4.77	$32.12
320 W	Metal Halide	$31.82	365	350	$0.0454	$5.80	$37.62
400 W	Metal Halide	$36.93	460	350	$0.0454	$7.31	$44.24
1,000 W	Metal Halide	$75.74	1050	350	$0.0454	$16.70	$92.43
20 - 29 W	LED	$9.74	25	350	$0.0454	$0.40	$10.14
30 - 39 W	LED	$10.47	35	350	$0.0454	$0.56	$11.02
40 - 49 W	LED	$11.19	45	350	$0.0454	$0.72	$11.91
50 - 59 W	LED	$11.92	55	350	$0.0454	$0.87	$12.79
60 - 69 W	LED	$12.64	65	350	$0.0454	$1.03	$13.68
70 - 79 W	LED	$13.38	75	350	$0.0454	$1.19	$14.58
80 - 89 W	LED	$14.15	85	350	$0.0454	$1.35	$15.50
90 - 99 W	LED	$14.95	95	350	$0.0454	$1.51	$16.46
100 - 109 W	LED	$15.78	105	350	$0.0454	$1.67	$17.45
110 - 119 W	LED	$16.66	115	350	$0.0454	$1.83	$18.49
120 - 129 W	LED	$17.54	125	350	$0.0454	$1.99	$19.53
130 - 139 W	LED	$18.49	135	350	$0.0454	$2.15	$20.64
140 - 149 W	LED	$19.16	145	350	$0.0454	$2.31	$21.46
150 - 159 W	LED	$19.62	155	350	$0.0454	$2.46	$22.09
160 - 169 W	LED	$20.04	165	350	$0.0454	$2.62	$22.66
170 - 179 W	LED	$20.47	175	350	$0.0454	$2.78	$23.26
180 - 189 W	LED	$20.91	185	350	$0.0454	$2.94	$23.85
190 - 199 W	LED	$21.34	195	350	$0.0454	$3.10	$24.45
200 - 209 W	LED	$21.78	205	350	$0.0454	$3.26	$25.04
210 - 219 W	LED	$22.25	215	350	$0.0454	$3.42	$25.67
220 - 229 W	LED	$22.73	225	350	$0.0454	$3.58	$26.30
230 - 239 W	LED	$23.20	235	350	$0.0454	$3.74	$26.94
240 - 249 W	LED	$23.67	245	350	$0.0454	$3.90	$27.57
250 - 259 W	LED	$24.14	255	350	$0.0454	$4.05	$28.20
260 - 269 W	LED	$24.62	265	350	$0.0454	$4.21	$28.83
270 - 279 W	LED	$25.09	275	350	$0.0454	$4.37	$29.46

(Continued on Sheet No. D-50.02)

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Regulatory Affairs

Detroit, Michigan

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in Case No. U-20162

(Continued from Sheet No. D-50.01)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Luminaire Charges (Contd.):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
280 - 289 W	LED	***$25.56***	285	350	***$0.0454***	***$4.53***	***$30.09***
290 - 299 W	LED	***$26.08***	295	350	***$0.0454***	***$4.69***	***$30.77***
300 - 309 W	LED	***$26.59***	305	350	***$0.0454***	***$4.85***	***$31.44***
310 - 319 W	LED	***$27.12***	315	350	***$0.0454***	***$5.01***	***$32.13***
320 - 329 W	LED	***$27.65***	325	350	***$0.0454***	***$5.17***	***$32.82***
330 - 339 W	LED	***$28.18***	335	350	***$0.0454***	***$5.33***	***$33.51***
340 - 349 W	LED	***$28.71***	345	350	***$0.0454***	***$5.49***	***$34.20***
350 - 359 W	LED	***$29.25***	355	350	***$0.0454***	***$5.64***	***$34.89***
360 - 369 W	LED	***$29.78***	365	350	***$0.0454***	***$5.80***	***$35.58***
370 - 379 W	LED	***$30.31***	375	350	***$0.0454***	***$5.96***	***$36.27***
380 - 389 W	LED	***$30.84***	385	350	***$0.0454***	***$6.12***	***$36.96***
390 - 399 W	LED	***$31.37***	395	350	***$0.0454***	***$6.28***	***$37.65***

Multiple Lamps on a Single Pole

- For each additional luminaire added to the same pole, reduce rate per lamp per year on the added luminaire $12.24.

The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those luminaires fail. At that time, ***the luminaire will be converted to LED***.

(Continued on Sheet No. D-51.00)

M.P.S.C. No. 1 - Electric ________Revised Sheet No. D-51.00
DTE Electric Company Cancels________Revised Sheet No. D-51.00
(Final Order Case No. U-20162)

(Continued from Sheet No. D-50.02)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Option I: Company Owned Street Lighting System (Contd.)
MONTHLY RATES OPTION I: Ornamental Underground Municipal Street Lighting for Lamp Spacing up to 120 Feet of Street ***(***All-night service***)***.

Power Supply Charges:
Capacity Energy Charge: 0.00¢ per kWh for all kWh
Non-Capacity Energy Charge: ***4.54***¢ per kWh for all kWh

Luminaire Charges:

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average *Monthly* Cost**
100 W	Mercury Vapor	***$27.08***	120	350	***$0.0454***	***$1.91***	***$28.99***
175 W	Mercury Vapor	***$30.30***	210	350	***$0.0454***	***$3.34***	***$33.64***
250 W	Mercury Vapor	***$35.19***	300	350	***$0.0454***	***$4.77***	***$39.96***
400 W	Mercury Vapor	***$43.63***	450	350	***$0.0454***	***$7.16***	***$50.78***
1,000 W	Mercury Vapor	***$80.32***	1060	350	***$0.0454***	***$16.85***	***$97.18***
70 W	High Pressure Sodium	***$22.78***	95	350	***$0.0454***	***$1.51***	***$24.29***
100 W	High Pressure Sodium	***$24.21***	135	350	***$0.0454***	***$2.15***	***$26.35***
150 W	High Pressure Sodium	***$26.53***	200	350	***$0.0454***	***$3.18***	***$29.71***
250 W	High Pressure Sodium	***$30.96***	305	350	***$0.0454***	***$4.85***	***$35.81***
360 W	High Pressure Sodium	***$35.73***	418	350	***$0.0454***	***$6.65***	***$42.38***
400 W	High Pressure Sodium	***$37.41***	465	350	***$0.0454***	***$7.39***	***$44.81***
1,000 W	High Pressure Sodium	***$66.98***	1100	350	***$0.0454***	***$17.49***	***$84.47***
70 W	Metal Halide	***$26.64***	85	350	***$0.0454***	***$1.35***	***$28.00***
100 W	Metal Halide	***$27.90***	120	350	***$0.0454***	***$1.91***	***$29.80***
150 W	Metal Halide	***$30.04***	180	350	***$0.0454***	***$2.86***	***$32.91***
175 W	Metal Halide	***$31.12***	210	350	***$0.0454***	***$3.34***	***$34.45***
250 W	Metal Halide	***$35.90***	300	350	***$0.0454***	***$4.77***	***$40.67***
320 W	Metal Halide	***$40.02***	365	350	***$0.0454***	***$5.80***	***$45.83***
400 W	Metal Halide	***$44.73***	460	350	***$0.0454***	***$7.31***	***$52.04***
1,000 W	Metal Halide	***$80.04***	1050	350	***$0.0454***	***$16.70***	***$96.74***
20 - 29 W	LED	***$18.65***	25	350	***$0.0454***	***$0.40***	***$19.05***
30 - 39 W	LED	***$19.18***	35	350	***$0.0454***	***$0.56***	***$19.73***
40 - 49 W	LED	***$19.70***	45	350	***$0.0454***	***$0.72***	***$20.42***
50 - 59 W	LED	***$20.24***	55	350	***$0.0454***	***$0.87***	***$21.12***
60 - 69 W	LED	***$20.80***	65	350	***$0.0454***	***$1.03***	***$21.83***
70 - 79 W	LED	***$21.36***	75	350	***$0.0454***	***$1.19***	***$22.55***
80 - 89 W	LED	***$21.93***	85	350	***$0.0454***	***$1.35***	***$23.28***
90 - 99 W	LED	***$22.53***	95	350	***$0.0454***	***$1.51***	***$24.04***
100 - 109 W	LED	***$23.14***	105	350	***$0.0454***	***$1.67***	***$24.81***
110 - 119 W	LED	***$23.78***	115	350	***$0.0454***	***$1.83***	***$25.61***
120 - 129 W	LED	***$24.44***	125	350	***$0.0454***	***$1.99***	***$26.43***
130 - 139 W	LED	***$25.13***	135	350	***$0.0454***	***$2.15***	***$27.27***
140 - 149 W	LED	***$25.64***	145	350	***$0.0454***	***$2.31***	***$27.94***

Continued on Sheet No. D-51.01)

Issued , 2019 Effective for service rendered on
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D. M. Stanczak and after _________, 2019
Vice President

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Detroit, Michigan dated__________, 2019

in Case No. U-20162

M.P.S.C. No. 1 - Electric ________Revised Sheet No. D-51.01
DTE Electric Company Cancels________Revised Sheet No. D-51.01
(Final Order Case No. U-20162)

(Continued from Sheet No. D-51.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Luminaire Charges (Contd):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average Monthly Cost**
150 - 159 W	LED	***$26.15***	155	350	***$0.0454***	***$2.46***	***$28.62***
160 - 169 W	LED	***$26.68***	165	350	***$0.0454***	***$2.62***	***$29.30***
170 - 179 W	LED	***$27.20***	175	350	***$0.0454***	***$2.78***	***$29.99***
180 - 189 W	LED	***$27.74***	185	350	***$0.0454***	***$2.94***	***$30.68***
190 - 199 W	LED	***$28.28***	195	350	***$0.0454***	***$3.10***	***$31.38***
200 - 209 W	LED	***$28.83***	205	350	***$0.0454***	***$3.26***	***$32.09***
210 - 219 W	LED	***$29.40***	215	350	***$0.0454***	***$3.42***	***$32.82***
220 - 229 W	LED	***$29.97***	225	350	***$0.0454***	***$3.58***	***$33.55***
230 - 239 W	LED	***$30.55***	235	350	***$0.0454***	***$3.74***	***$34.29***
240 - 249 W	LED	***$31.12***	245	350	***$0.0454***	***$3.90***	***$35.02***
250 - 259 W	LED	***$31.70***	255	350	***$0.0454***	***$4.05***	***$35.75***
260 - 269 W	LED	***$32.27***	265	350	***$0.0454***	***$4.21***	***$36.48***
270 - 279 W	LED	***$32.88***	275	350	***$0.0454***	***$4.37***	***$37.25***
280 - 289 W	LED	***$33.49***	285	350	***$0.0454***	***$4.53***	***$38.02***
290 - 299 W	LED	***$34.11***	295	350	***$0.0454***	***$4.69***	***$38.80***
300 - 309 W	LED	***$34.74***	305	350	***$0.0454***	***$4.85***	***$39.59***
310 - 319 W	LED	***$35.36***	315	350	***$0.0454***	***$5.01***	***$40.37***
320 - 329 W	LED	***$35.99***	325	350	***$0.0454***	***$5.17***	***$41.16***
330 - 339 W	LED	***$36.62***	335	350	***$0.0454***	***$5.33***	***$41.94***
340 - 349 W	LED	***$37.24***	345	350	***$0.0454***	***$5.49***	***$42.73***
350 - 359 W	LED	***$37.87***	355	350	***$0.0454***	***$5.64***	***$43.51***
360 - 369 W	LED	***$38.50***	365	350	***$0.0454***	***$5.80***	***$44.30***
370 - 379 W	LED	***$39.12***	375	350	***$0.0454***	***$5.96***	***$45.08***
380 - 389 W	LED	***$39.75***	385	350	***$0.0454***	***$6.12***	***$45.87***
390 - 399 W	LED	***$40.37***	395	350	***$0.0454***	***$6.28***	***$46.65***

Long Span

- For lamp spacing over 120 feet up to 325 feet on the same side of street, add to rate per lamp per year.. $24.48

Semi-Ornamental

- For Semi-Ornamental Systems which employ Ornamental Post Units served from overhead conductors, where such construction is practical, reduce rate per luminaire per year $21.48

Post Charge

- ***For each increment of $1,000 of investment which exceeds three times the annual revenue at the prevailing rate at the time of installation, add to rate per year... $80.15***

Multiple Luminaires on a Single Pole

- For additional luminaire**s** added to the same pole, a reduced rate per luminaire per year on the added luminaire**.**
  Ornamental $97.92
  Ornamental-Lamp spacing over 120 feet $122.40
  Semi-Ornamental $76.56

(Continued on Sheet No. D-52.00)

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M.P.S.C. No. 1 - Electric _______Revised Sheet No. D-52.00
DTE Electric Company Cancels________Revised Sheet No. D-52.00
(Final Order Case No. U-20162)

(Continued from Sheet No. D-51.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

OPTION II: Street Equipment Owned by Municipality

MONTHLY RATES OPTION II: Overhead and Underground Ornamental Municipality Owned Street Lighting (All-night service**)**.

Power Supply Charges:
Capacity Energy Charge: 0.00¢ per kWh for all kWh
Non-Capacity Energy Charge: ***4.54***¢ per kWh for all kWh

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	**Type of Service**	**Distribution Charge per Lamp per Month**	**System Wattage**	**Average Monthly Hours (4200/12)**	**Energy Charge**	**Average Energy Cost per Month (d*e*f/1000)**	**Average *Monthly* Cost**
175 W	Mercury Vapor	***$7.06***	210	350	***$0.0454***	***$3.34***	***$10.40***
250 W	Mercury Vapor	***$8.25***	300	350	***$0.0454***	***$4.77***	***$13.02***
400 W	Mercury Vapor	***$13.65***	450	350	***$0.0454***	***$7.16***	***$20.81***
1,000 W	Mercury Vapor	***$30.12***	1060	350	***$0.0454***	***$16.85***	***$46.97***
70 W	High Pressure Sodium	***$4.06***	95	350	***$0.0454***	***$1.51***	***$5.57***
100 W	High Pressure Sodium	***$4.99***	135	350	***$0.0454***	***$2.15***	***$7.14***
250 W	High Pressure Sodium	***$9.67***	305	350	***$0.0454***	***$4.85***	***$14.52***
360 W	High Pressure Sodium	***$12.89***	418	350	***$0.0454***	***$6.65***	***$19.54***
400 W	High Pressure Sodium	***$14.07***	465	350	***$0.0454***	***$7.39***	***$21.46***
1,000 W	High Pressure Sodium	***$31.66***	1100	350	***$0.0454***	***$17.49***	***$49.16***

- The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those luminaires fail. At that time, customers will be given the option of switching to High Pressure Sodium, Metal Halide, LED or retiring the Luminaire.
- **DE-ENERGIZED LIGHTS:** Customers may elect to have any or all luminaires served under this rate disconnected. The charge per luminaire per year, payable in equal monthly installments, shall be 10% of the above yearly rates. A $35.00 charge per luminaire will be made at the time of de-energization and at the time of re-energization.
- **DUSK TO MIDNIGHT SERVICE:** For service to parking lots from dusk to approximately twelve o'clock midnight E.S.T., a discount of 1.060¢ per nominal watt per month will be applied. One control per circuit will be provided.

(Continued on Sheet No. D-53.00)

Issued __________, 2019
D. M. Stanczak
Vice President
Regulatory Affairs

Detroit, Michigan

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(Continued from Sheet No. D-52.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

OPTION III: ***(Unmetered)*** Municipally Owned and Maintained Street Lighting System.

HOURS OF SERVICE: For circuits controlled by automatic timing devices, one-half hour after sunset until one-half hour before sunrise. For circuits controlled by photo-sensitive devices, dusk to dawn for approximately 4,200 hours per year.

RATES: Where the municipality owns, operates, cleans and renews the lamps, and the Company's service is confined solely to the supply of electricity from dusk to dawn, the monthly charge of said service shall be a power supply capacity energy charge of 0.00¢ per kilowatthour, a power supply non-capacity charge of ***4.54¢*** per kilowatthour and a distribution charge of ***8.38¢*** per kilowatthour. If it is necessary for the Company to install facilities to provide service for the lamps, the customer will reimburse the Company for these costs. Contract Rider No. 2 charges will also apply.

OPTION III: —***(Controlled/Metered)*** Municipally Owned and Maintained Street Lighting System

AVAILABILITY OF SERVICE: Available to governmental agencies desiring controlled nighttime service for primary or secondary voltage energy-only street lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires served under any of the Company's other street lighting rates shall not be intermixed with luminaires serviced under this street lighting rate. This rate is not available for resale purposes. Service is governed by the Company's Standard Rules and Regulations.

KIND OF SERVICE:

Secondary Voltage Service: Alternating current, 60 hertz, single-phase 120/240 nominal volt service for a minimum of ten luminaires located within a clearly defined area. Except for control equipment, the customer will furnish, install, own and maintain all equipment comprising the street lighting system up to the point of attachment with the Company's distribution system. The Company will connect the customer's equipment to the Company's lines and supply the energy for operation. All of the customer's equipment will be subject to the Company's review.

Primary Voltage Service: Alternating current, 60 hertz, single-phase or three-phase, primary voltage service for actual demands of not less than 100 kW at each point of delivery. The particular nature of the voltage shall be determined by the Company. The customer will furnish, install, own and maintain all equipment comprising the street lighting system, including control equipment, up to the point of attachment with the Company's distribution system. The Company will supply the energy for operation of the customer's street lighting system.

(Continued on Sheet No. D-54.00)

(Continued from Sheet No. D-53.00)

RATE SCHEDULE NO. E1 (Contd.) **MUNICIPAL STREET LIGHTING RATE**

Primary and Secondary Energy
Full Service Customers:

Power Supply Charge:

Capacity Energy Charge: ***2.251¢*** per kWh for all kWh
Non-Capacity Energy Charge*:* ***3.208¢*** per kWh for all kWh

Delivery System Charge:

3.866¢ per kWh based on the capacity requirements in kilowatts of the equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE***:***

Capacity Energy Charge***:*** ***2.251¢*** per kWh for all kWh

Delivery System Charge:

3.866¢ per kWh based on the capacity requirements in kilowatts of the equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption and the total annual kWh consumption.

At the Company's option, service may be metered and the metered kWh will be the basis for billing. Capacity requirements of lighting equipment shall be determined by the Company from manufacturer specifications, but the Company maintains the right to test such capacity requirements from time to time. In the event that Company tests show capacity requirements other than those indicated in manufacturer specifications, the capacity requirements indicated by Company tests will be used. The customer shall not change the capacity requirements of its equipment without first notifying the Company in writing.

BILLING: Billing will be on a monthly basis.

SURCHARGES AND CREDITS: As approved by the Commission. Power Supply Charges are subject to Section C8.5. Delivery Charges are subject to Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The contract minimum.

CONTRACT TERM: Contracts will be taken for a minimum of two years, extending thereafter from year to year until terminated by mutual consent or upon 12 months' written notice by either party.

RATE SCHEDULE NO. E2 **TRAFFIC AND SIGNAL LIGHTS**

AVAILABILITY OF SERVICE: Available to municipalities or other public authorities, hereinafter referred to as customer, operating lights for traffic regulation or signal lights on streets, highways, airports or water routes, as distinguished from street lighting. Customers desiring service under Rate Schedule No. E2 are free to determine the appropriate light source for their application including incumbent and emerging technologies (including LEDs). Customers must supply adequate documentation of the wattage of the light source that will be subject to the approval of the Company.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, at 120 volts two-wire.

SERVICE CONNECTIONS: The customer is to furnish and maintain all necessary wiring and equipment, including lamps and lamp replacements, or reimburse the Company therefore, except that the Company will furnish, install and maintain such span poles and messenger cable as may be needed to support the traffic or signal lights of the overhead type. Connections are to be brought to the Company's underground and overhead lighting mains by the customer as directed by the Company, and the final connection to the Company's main is to be made by the Company.

Conversion and/or relocation of existing facilities must be paid for by the customer, except when initiated by the Company. The detailed provisions and schedule of such charges will be quoted upon request.

RATES: Distribution charge of ***1.86¢***, capacity energy charge of ***1.82¢*** and non-capacity energy charge of ***4.41¢*** per month per kilowatthour of the total connected traffic light or signal light load in service for each customer.

Total connected wattage will be reckoned as of the fifteenth of the month. Lamps removed from service before the fifteenth or placed in service on or after the fifteenth will be omitted from the reckoning; conversely, lamps placed in service on or before the fifteenth of the month or removed from service after the fifteenth of the month will be reckoned for a full month. Lamps operated cyclically, on and off, will be reckoned at one-half wattage and billed for a full month. No such reduction of reckoned wattage will be allowed for lamps in service but turned off during certain hours of the day.

The Company may, at its option, install meters and apply a standard metered rate schedule applicable to the service.

SURCHARGES AND CREDITS: As approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: $3.00 per customer per month.

CONTRACT TERM: Open order on a month-to-month basis. However, the Company shall not withdraw service, and the customer shall not substitute another source of service in whole or in part, without twelve months' written notice to the other party.

STANDARD CONTRACT RIDER NO. 1.1 **ALTERNATIVE ELECTRIC METAL MELTING**

APPLICABLE TO:

General Service Rate	Schedule Designation D3
Large General Service Rate	Schedule Designation D4
Interruptible Supply Rate	Schedule Designation D8
Primary Supply Rate	Schedule Designation D11

Customers operating electric furnaces for metal melting or for the reduction of metallic ores and/or electric use consumed in holding operations and taking their supply at any of the above rates and who provide special circuits so that the Company may install necessary meters, may take service under this Rider subject to Section C4.4 - Choice of Rates..

Customers shall be subject to immediate interruption on short-term notice if necessary, in order to maintain system integrity. The customer shall be provided, whenever possible, notice in advance of probable interruption and estimated duration of interruption.

Non-Compliance Penalty: A customer who does not interrupt within one hour following a system integrity interruption order shall be billed at the rate of $10 per kW for the highest 30-minute kW demand created during the interruption period in addition to the prescribed monthly rate.

Electric energy from any facilities, other than the Company's, except for on-site generation installed prior to January 1, 1986, will be used to first reduce the sales on this rider. Standby service will not be billed at this rider, but must be taken under Riders No. 3, No. 5 or No. 6.

RATE PER MONTH:

Full Service Customers:
Power Supply Charges:
Capacity
Energy Charges:
For service at secondary voltage level (less than 4.8 kV)
2.498¢ per kWh for the first 100 hours use of maximum demand
0.943¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.857¢ per kWh for the first 100 hours use of maximum demand
0.678¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
1.813¢ per kWh for the first 100 hours use of maximum demand
0.630¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
1.537¢ per kWh for the first 100 hours use of maximum demand
0.509¢ per kWh for the excess

Non-Capacity
Energy Charge***:*** ***4.515¢*** per kWh for all kWh

(Continued on Sheet No. D-58.00)

(Continued from Sheet No. D-57.00)

STANDARD CONTRACT RIDER NO. 1.1 (Contd.) **ALTERNATIVE ELECTRIC METAL MELTING**

Delivery Charges:

Distribution Charges:

For service at secondary voltage level (less than 4.8 kV)
2.686¢ per kWh for the first 100 hours use of maximum demand
2.686¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.207¢ per kWh for the first 100 hours use of maximum demand
1.207¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
0.342¢ per kWh for the first 100 hours use of maximum demand
0.342¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
0.133¢ per kWh for the first 100 hours use of maximum demand
0.133¢ per kWh for the excess

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8

Retail Access Service Customers*:*

Capacity (Only applicable to Retail access Service Customers receiving Utility Capacity Service from DTE Electric*)*

Energy Charges:

For service at secondary voltage level (less than 4.8 kV)
2.498¢ per kWh for the first 100 hours use of maximum demand
0.943¢ per kWh for the excess

(Continued on Sheet No. D-59.00)

(Continued from Sheet No. D-58.00)

STANDARD CONTRACT RIDER NO. 1.1 (Contd.) **ALTERNATIVE ELECTRIC METAL MELTING**

Retail Access Service Customers:

For service a primary voltage level (4.8 kV to 13.2 kV)
1.857¢ per kWh for the first 100 hours use of maximum demand
0.678¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
1.813¢ per kWh for the first 100 hours use of maximum demand
0.630¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
1.537¢ per kWh for the first 100 hours use of maximum demand
0.509¢ per kWh for the excess

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:
Distribution Charges:
For service at secondary voltage level (less than 4.8 kV)
2.686¢ per kWh for the first 100 hours use of maximum demand
2.686¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.207¢ per kWh for the first 100 hours use of maximum demand
1.207¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
0.342¢ per kWh for the first 100 hours use of maximum demand
0.342¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
0.133¢ per kWh for the first 100 hours use of maximum demand
0.133¢ per kWh for the excess

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

(Continued from Sheet No. D-60.00)

STANDARD CONTRACT RIDER NO. 1.2 **ELECTRIC PROCESS HEAT**

APPLICABLE TO:

General Service Rate	Schedule Designation D3
Large General Service Rate	Schedule Designation D4
Interruptible Supply Rate	Schedule Designation D8
Primary Supply Rate	Schedule Designation D11

Customers using electric heat as an integral part of a manufacturing process, or electricity as an integral part of an anodizing, plating or coating process, and taking their supply at any of the above rates and who provide special circuits to accommodate separate metering may take service under this Rider subject to Section C4.4- Choice of Rates.

This Rider is available only to customers who add new load on or after May 1, 1986 to engage in the above described processes and to customers served on R1.1 prior to May 1, 1986 and engaged in the above described processes.

Customers shall be subject to immediate interruption on short-term notice if necessary, in order to maintain system integrity. The customer shall be provided, whenever possible, notice in advance of probable interruption and estimated duration of interruption.

Non-Compliance Penalty: A customer who does not interrupt within one hour following a system integrity interruption order shall be billed at the rate of $10 per kW for the highest 30-minute kW demand created during the interruption period in addition to the prescribed monthly rate.

Electric energy from any facilities, other than the Company's, except for on-site generation installed prior to January 1, 1986, will be used to first reduce the sales on this rider. Standby service will not be billed at this rider, but must be taken under Riders No. 3, No. 5 or No. 6.

RATE PER MONTH:
Full Service Customers:

Power Supply Charges:
Capacity
Energy Charges:
For service at secondary voltage level (less than 4.8 kV)
2.498¢ per kWh for the first 100 hours use of maximum demand
0.943¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.857¢ per kWh for the first 100 hours use of maximum demand
0.678¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
1.813¢ per kWh for the first 100 hours use of maximum demand
0.630¢ per kWh for the excess

(Continued on Sheet No. D-62.00)

(Continued from Sheet No. D-61.00)

STANDARD CONTRACT RIDER NO. 1.2 (Contd.) **ELECTRIC PROCESS HEAT**

For service at transmission voltage level (120 kV and above)
1.537¢ per kWh for the first 100 hours use of maximum demand
0.509¢ per kWh for the excess

Non-Capacity
Energy Charge***: 4.515¢ per kWh for all kWh***

Delivery Charges:
Distribution Charges:
For service at secondary voltage level (less than 4.8 kV)
2.686¢ per kWh for the first 100 hours use of maximum demand
2.686¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.207¢ per kWh for the first 100 hours use of maximum demand
1.207¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
0.342¢ per kWh for the first 100 hours use of maximum demand
0.342¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
0.133¢ per kWh for the first 100 hours use of maximum demand
0.133¢ per kWh for the excess

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Energy Charges:
For service at secondary voltage level (less than 4.8 kV)
2.498¢ per kWh for the first 100 hours use of maximum demand
0.943¢ per kWh for the excess

(Continued on Sheet No. D-63.00)

(Continued from Sheet No. D-62.00)

STANDARD CONTRACT RIDER NO. 1.2 (Contd.) **ELECTRIC PROCESS HEAT**

Retail Access Service Customers:

For service at primary voltage level (4.8 kV to 13.2 kV)
1.857¢ per kWh for the first 100 hours use of maximum demand
0.678¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
1.813¢ per kWh for the first 100 hours use of maximum demand
0.630¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
1.537¢ per kWh for the first 100 hours use of maximum demand
0.509¢ per kWh for the excess

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:
Distribution Charges:

For service at secondary voltage level (less than 4.8 kV)
2.686¢ per kWh for the first 100 hours use of maximum demand
2.686¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)
1.207¢ per kWh for the first 100 hours use of maximum demand
1.207¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)
0.342¢ per kWh for the first 100 hours use of maximum demand
0.342¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)
0.133¢ per kWh for the first 100 hours use of maximum demand
0.133¢ per kWh for the excess

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

(Continued on Sheet No. D-64.00)

(Continued from Sheet No. D-70.00)

STANDARD CONTRACT RIDER NO. 3 (Contd.) **PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE**

DEFINITIONS (contd):

MAINTENANCE PERIODS (contd):

(e) If there is a substantial change in circumstances which make the agreed upon schedule impractical for either party, the other party upon request shall make reasonable efforts to adjust the schedule in a manner that is mutually agreeable.

WAIVERS AND LIMITS FOR GENERATION RESERVATION FEE AND DAILY DEMAND CHARGES*:*
For customers taking supplemental service on rate schedules D4, D11, D6.2 or D8, the following waivers apply:

If the total of daily demand charges for the month is less than the monthly generation reservation fee, then the daily demand charges will be waived for that month.

If the total of daily demand charges for the month is greater than the monthly generation reservation fee, then the generation reservation fee will be waived for that month.

Waivers and limits for energy-only rates:
For customers taking supplemental service on energy-only rates for the entire billing cycle, schedules D3, or D3.3, the following applies.

If the total of daily demand charges for the month is less than the monthly generation reservation fee, then the daily demand charges will be waived for that month.

If the total of daily demand charges for the month is greater than the monthly generation reservation fee, then the daily demand charges will be waived for that month provided that the supplemental rate continues as an energy-only rate**.** If not, then the total of daily demand charges for the month will be charged and the generation reservation fee for the month will be waived.

RATES:

Power Supply Charges:

Capacity

Monthly Generation Reservation Fee:

$***0.45*** times the standby contract capacity in kW, per month.

The daily on-peak backup demand charge is $***1.23*** per kW per day during periods other than maintenance periods as defined below.

The daily on-peak backup demand charge is $***0.62*** per kW per day during maintenance periods as defined below.

(Continued from Sheet No. D-72.00)

(Continued from Sheet No. D-72.00)

STANDARD CONTRACT RIDER NO. 3 (Contd.) **PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE**

RATES (contd):

Energy Charge:

For customers served on supplemental rate schedules D3, D3.2 and D3.3, the energy charge will be the applicable power supply energy charge specified in the customer's supplemental rate.

The energy as stated herein, is also subject to provisions of the PSCR clause and other Surcharges and Credits Applicable to Power Supply as approved by the Commission. See Section C8.5.

Non-Capacity
Monthly Generation Reservation Fee:

$***0.17*** times the standby contract capacity in kW, per month.

The daily on-peak backup demand charge is $***0.47*** per kW per day during periods other than maintenance periods as defined below.

The daily on-peak backup demand charge is $***0.23*** per kW per day during maintenance periods as defined below.

Energy Charge:

An energy charge for back-up and maintenance power will be charged based on standby contract capacity less the output toward internal load of the customer's generator, but not less than zero. For customers served on supplemental rate schedules D4, D11, D6.2 and D8, the energy charge will be ***4.339¢*** per kWh, plus appropriate power supply credits, including but not limited to an off-peak credit of 1.00¢ per kWh, and voltage level credits of ***0.119¢*** per kWh for subtransmission and ***0.201¢*** per kWh for transmission. For customers served on supplemental rate schedules D3, D3.2 and D3.3, the energy charge will be the applicable power supply energy charge specified in the customer's supplemental rate.

The energy as stated herein, is also subject to provisions of the PSCR clause and other Surcharges and Credits Applicable to Power Supply as approved by the Commission. See Section C8.5.

Delivery Charges:

Service Charge:

$53.52 per customer per month for customers served at primary voltage.
$375 per customer per month for customers served above primary voltage.
$95 per customer per month for customers served at secondary voltages.

Distribution Charge:

Distribution charges will be as follows:

$***4.07*** per kW at primary voltage applied to the standby contract capacity
$***1.46*** per kW at subtransmission voltage applied to the standby contract capacity
$***0.65*** per kW at transmission voltage applied to the standby contract capacity

(Continued on Sheet No. D-73.00)

(Continued from Sheet No. D-72.00)

STANDARD CONTRACT RIDER NO. 3 (Contd.) **PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE**

RATES (contd):

Distribution Charge:

For service provided in conjunction with a secondary voltage base rate the Delivery Charge will be the greater of $9.66 per kW applied to standby contract capacity or ***3.866*¢**/kWh applied to all standby energy delivered.

Substation Credit: Available to customers served at subtransmission voltage level (24 to 41.6 kW) or higher who provide the on-site substation including all necessary transforming, controlling, and protective equipment. A credit of $.30 per kW shall be applied to the distribution demand charge per kW of standby capacity. An additional credit of 0.040¢ per kWh of standby delivered will be given where the service is metered on the high voltage side of the transformer.

Surcharges and Credits Applicable to Delivery Service: As approved by the Commission. See Section C9.8.

ADJUSTMENT OF PRIOR RATCHETS: When a customer takes standby service under Rider No. 3, the setting or the increasing or decreasing of standby contract capacity will affect the existing ratchet levels on the supplemental rate as follows:

(a) An amount in kW equal to the initial standby contract capacity (or to the increase or decrease) will be subtracted from (or subtracted from or added to) the existing ratcheted maximum demand level for customers on supplemental rates D6.2 and D8 and D11.

(b) An amount in kW equal to 65% of the initial standby contract capacity (or of the increase or decrease) will be subtracted from (or subtracted from or added to) the existing ratcheted on-peak billing demand level for customers on supplemental rates D4, D6.2 and D8 and D11.

LATE PAYMENT CHARGE: See Section C4.8.

SCHEDULE OF ON-PEAK HOURS: See Section C11.

POWER FACTOR CLAUSE: The rates and charges under this tariff are based on the customer maintaining a power factor of not less than 85% lagging. Customers are responsible for correcting power factors less than 70% at their own expense. The size, type and location of any power factor correction equipment must be approved by the Company. Such approval will not be unreasonably withheld. A penalty will be applied to the total amount of the monthly billing for supplemental and standby service for power factor below 85% lagging in accordance with the table in Power Factor Determination, Section C12. The penalty will not be applied to the on-peak billing demand ratchet nor to the minimum contract demand of the supplemental rate, but will be applied to metered quantities.

(Continued on Sheet No. D-73.01)

(Continued from Sheet No. D-73.01)

STANDARD CONTRACT RIDER NO. 3 (Contd.) **PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE**

STATION POWER STANDBY SERVICE

SERVICE UNDER THIS PROVISION BECOMES EFFECTIVE APRIL 1, 2014

STATION POWER STANDBY SERVICE: Available to customers with generation facilities that are located within the Company's retail service territory and that are interconnected to ITC Transmission. The power supply requirements necessary to maintain and operate the generating facility that are normally served by the facility's on-site generation but which instead are provided by the facility's taking power through its transmission interconnection must be provided under the station Power Standby Service provisions of this rider.

APPLICABLE TO: General Service Rate Schedule Designation D3

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CONTRACT CAPACITY: Customers shall initially contract for a specified capacity in kilowatts sufficient to meet expected maximum requirements. Any single reading of the demand meter or aggregation of demand meters recording inflow to the facility in any month that exceeds the contract capacity then in effect shall become the new contract capacity.

METERING REQUIREMENTS: All customers taking service under this rider must install the necessary equipment to permit metering. The Company will supply the metering equipment. Service to the customer under this Rider will be metered with demand-recording equipment. Any equipment installed by the customer necessary to accommodate the Company's metering equipment must be approved by the Company and must be compatible with the Company's Meter Data Acquisition System.

RATES:

Power Supply:

Non-Capacity

Station Power Energy Service will be priced on the basis of the real time MISO locational hourly marginal energy price for the Company-appropriate load node. In additional to the MISO locational hourly marginal energy price the following charges will also apply:

0.736¢/kWh for MISO network transmission costs and MISO energy market costs plus,
An administrative charge of ***1.665***¢/kWh plus,
Surcharges and Credits Applicable to Power Supply, excluding PSCR, as approved by the Commission. See Section C8.5

Service Charge:

Primary Service Charge:	***$53.52*** per month
Subtransmission and Transmission Service Charge:	$375 per month

(Continued on Sheet No. D-73.03)

STANDARD CONTRACT RIDER NO. 4 **RESALE OF SERVICE**

APPLICABLE TO:

General Service Rate	Schedule Designation D3
Large General Service Rate	Schedule Designation D4
Primary Supply Rate	Schedule Designation D11
Retail Access Service Tariff	Schedule Designation EC2

Electricity supplied to a customer is for his exclusive use on the premises to which it is delivered by the Company. Customers desiring to resell electric service to their tenants must secure authority from the Company which will be evidenced by a rider attached to the contract for service. Resale option is closed to new service or expanded service for resale for residential service as of March 31, 1979. ***Neither the resale of electric services provided by DTE Electric Company nor the sale of self-generation at publicly available electric vehicle charging stations is subject to Commission regulation and no restrictions are imposed on the rate charged or rate structure to the ultimate motor vehicle customer, as those sales are being made into the competitive motor fuels market.***

If the reselling customer elects to take service under the DTE Electric Retail Access Service Tariff, the ultimate user (residential, commercial or industrial customer) shall be served and charged for such service under the Retail Access Service Tariff in the Company's rate schedule available for similar services under like conditions.

The reselling customer shall provide notice to tenants of the decision to obtain electric service pursuant to the Retail Access Service Tariff and that as a result power supply charges are no longer regulated by the Commission.

MULTIPLE OCCUPANCY BUILDINGS:

The owner or operator of an office building, apartment building, etc., with at least thirty tenants (or less at the option of the Company where extensions of the Company service to the individual tenants is impractical) whose combined requirements regularly exceed 20,000 kilowatthours per month, may purchase electric energy from the Company for resale to the tenants of the building on condition that service to each tenant shall be separately metered, and that the tenants shall be charged for such service the current rate of the Company for similar service under like conditions.

No landlord may charge his tenants more nor less for resold electric service purchased from the Company than the tenants would be charged by the Company if served directly. If this requirement is violated, the Company may refuse service to the building. The renting of premises with the cost of electric service included in the rental is held not to be a resale of service. The Company does not furnish nor maintain meters for the resale of energy by landlords to tenants.

MOBILE HOME PARKS:

In some cases it is not practical for the Company to furnish service directly to individual mobile homes in mobile home parks. Because of this, the park operators may purchase electric energy from the Company for resale to tenants, provided that service to each tenant buying energy shall be separately metered and billed at the Company's Residential Service Rate.

(Continued on Sheet No. D-77.00)

STANDARD CONTRACT RIDER NO. 7 **GREENHOUSE LIGHTING SERVICE**

APPLICABLE TO: General Service Rate Schedule Designation D3
Large General Service Rate Schedule Designation D4

Available on an optional basis to customers desiring high intensity discharge lighting service for greenhouses or other environmentally controlled growing facilities as a daylight supplement. All lighting on this rider shall be separately metered. The customer will furnish, install, own, and maintain all equipment comprising the lighting system. No other device may be connected to this circuit except for controls, lighting and associated equipment.

HOURS OF SERVICE: Dusk to dawn service for circuits controlled by photo-sensitive or clock timing devices.

CURRENT, PHASE AND VOLTAGE: Alternating current, 60 hertz, single phase, nominally at 120/240 volts, three-wire; or three-phase, four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase, four-wire, Y connected at 480Y/277 volts.

RATE PER MONTH:

Full Service Customers:

Power Supply Charge:
Capacity Energy Charge: ***1.884¢*** per kWh for all kWh
Non-Capacity Energy Charge: ***2.651¢*** per kWh for all kWh

Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***3.347¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charge for Retail Access Service Customers taking Utility Capacity Service for DTE:
Capacity Energy Charge: ***1.884¢*** per kWh for all kWh

Delivery Charges:
Service Charge: $1.95 per month
Distribution Charge: ***3.347¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8.

(Continued on Sheet No. D-85.00)

M.P.S.C. No. 1 - Electric _______Revised Sheet No. D-86.00
DTE Electric Company Cancels Fourth_______Revised Sheet No. D-86.00
(Final Order Case No. U-20162)

STANDARD CONTRACT RIDER NO. 8 **COMMERCIAL SPACE HEATING**

APPLICABLE TO:	General Service Rate	Schedule Designation D3
	Large General Service Rate	Schedule Designation D4

Available on an optional basis to customers desiring service for commercial space conditioning furnished through separately metered circuits to which no other device except electric space heating, water heating, air conditioning, or humidity control equipment may be connected and provided that all of the space heating must be either total electric or an electric heat pump supplemented by a fossil fuel furnace installed on a permanent basis. The customer must provide special circuits, the design and method of installation of which are approved by the Company as adapted to this service.

Electric space heating under the terms of this rider will be considered to include heating by light systems, provided the primary means of space heating at the time of maximum requirements will be furnished by the lighting system, with the balance furnished by supplementary electric heating equipment. After June 15, 1970, under the authority of the Commission in Case U-3189, service to facilities which heat by lighting is not available for premises not previously qualified for service hereunder.

RATE PER MONTH:

Full Service Customers:

Power Supply Charge:

Capacity Energy Charge: ***5.053¢*** per kWh for all kWh, except that during the billing months of November through May, usage in excess of 1,000 kWh per month shall be billed at ***1.676¢*** per kWh.

Non-Capacity Energy Charge: ***4.067¢*** per kWh

Delivery Charges:

Service Charge: $11.25 per month

Distribution Charge: ***3.866¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charge for Retail Access Service Customers taking Utility Capacity service from DTE:

Capacity Energy Charge: ***5.053¢*** per kWh for all kWh, except that during the billing months of November through May, usage in excess of 1,000 kWh per month shall be billed at ***1.676¢*** per kWh.

Delivery Charges:

Service Charge: $11.25 per month Distribution

Charge: ***3.866¢*** per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8.

(Continued on Sheet No. D-87.00)

Issued , 2019
D. M. Stanczak
Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after , 2019

Issued under authority of the
Michigan Public Service Commission
dated_____________, 2019
in Case No. U-20162

(Continued from Sheet No. D-86.00)

STANDARD CONTRACT RIDER NO. 8 (Contd.) **COMMERCIAL SPACE HEATING**

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: This rate is made effective by a rider modifying the contract form prescribed for one of the applicable filed rates listed above. The contract term is co-extensive with the contract term of the applicable filed rate under which service is being taken.

INSULATION STANDARDS FOR ELECTRIC HEATING: See Section C4.9.

OPTIONAL PROVISION FOR CERTAIN COMMON AREA ACCOUNTS: Electric heating and common area usage of apartment or condominium accounts supplied through a single meter and billed under the terms of the Domestic Space Heating Rate D2 prior to September 28, 1978 may be billed under this provision without the necessity of separate metering if an initial block of kilowatthours is billed at the current General Service Rate D3. This initial block of kilowatthours will be calculated each November by averaging the usage during the previous billing months of June through October.

Full Service Customers:

Usage in excess of the initial block of kilowatthours per month shall be billed at a power supply capacity charge of ***5.053¢*** and a non-capacity charge of ***4.067¢*** per kilowatthour during the billing months of June through October, and a capacity charge of ***1.676¢*** and a non-capacity charge of ***4.067¢*** per kilowatthour during the billing months of November through May. A Distribution charge of ***3.866¢*** per kWh for all kWh shall also be applied. The only service charge to be billed to a customer utilizing this provision will be the D3 service charge.

Retail Access Service Customers:

Power Supply Charge for Retail Access Service Customers taking Utility Capacity Service from DTE:

For Retail Access customers taking capacity service from DTE, usage in excess of the initial block of kilowatthours per month shall be billed at a power supply capacity charge of ***5.053¢*** per kilowatthour during the billing months of June through October, and a power supply capacity charge of ***1.676¢*** per kilowatthour during the billing months of November through May.

For all retail access customers, usage in excess of the initial block of kilowatthours per month shall be billed a distribution charge of ***3.866¢*** per kWh for all kWh.

SUPPLEMENTAL SPACE HEATING PROVISION: This provision is available to customers taking service under the General Service Rate D3 or the Large General Service Rate D4 who purchase energy for a minimum of 10 kW of supplemental, permanently installed, electric space heating equipment. To qualify for this provision, a customer must certify in writing the amount of permanently installed space heating equipment, subject to inspection at the option of the Company, and have the said equipment on separately metered circuits to which no other device is connected. Section C4.9, Insulation Standards for Electric Heating, will not apply to this provision.

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Final Order Case No. U-20162)

_______Revised Sheet No. D-91.00
Cancels_______Revised Sheet No. D-91.00

(Continued from Sheet No. D-90.00)

STANDARD CONTRACT RIDER NO. 10 (Contd.) **INTERRUPTIBLE SUPPLY RIDER**

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Non-Capacity:
The Energy charge will be the real time MISO locational hourly marginal energy price for the DTE Electric-appropriate load node. In addition to the MISO locational hourly marginal energy price the following charges will also apply:

0.736¢/kWh for MISO network transmission costs and MISO energy market costs plus,
An administrative charge of ***1.665*¢**/kWh plus,
A voltage level service adder of 1% for transmission, 2% for subtransmission and 7% for primary.

Delivery Charges:

Primary Service Charge:	***$53.52*** per month
Subtransmission and Transmission Service Charge:	$375 per month

Distribution Charges:
For primary service (less than 24kV) $***4.07*** per kW of maximum demand.
For service at subtransmission voltage (24 to 41.6 kV) $***1.46*** per kW of maximum demand. For service at transmission voltage (120 kV and above) $***0.65*** per kW of maximum demand

Substation Credit: Available to customers where service at subtransmission voltage level or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of .040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8

(Continued on Sheet No. D-92.00)

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D. M. Stanczak
Vice President
Regulatory Affairs

Detroit, Michigan

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(Continued from Sheet No. D-91.00)

STANDARD CONTRACT RIDER NO. 10 (Contd.) **INTERRUPTIBLE SUPPLY RIDER**

Retail Access Service Customers:

Delivery Charges:

Primary Service Charge: ***$53.52*** per month
Subtransmission and Transmission Service Charge: $375 per month
Distribution Charges:
For primary service (less than 24kV) $***4.07*** per kW of maximum demand
For service at subtransmission voltage (24 to 41.6 kV) $***1.46*** per kW of maximum demand For service at transmission voltage (120 kV and above) $***0.65*** per kW of maximum demand.

Substation Credit: Available to customers where service at subtransmission voltage level or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of $.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of .040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus the Maximum Demand Charge, plus all applicable energy charges plus any applicable per meter per month surcharge.

MAXIMUM DEMAND: The maximum demand shall be the highest 30-minute demand created during the previous 12 billing months, including the current month but not less than 50% of the contract capacity. This clause is applicable to each voltage level served.

POWER FACTOR CLAUSE: Shall be the Power Factor Clause as defined in the Primary Supply Rate (D11).

SPECIAL TERMS AND CONDITIONS: Customer-owned equipment must be operated so the voltage fluctuations on the primary distribution system of the Company shall not exceed permissible limits.

The customer will own and maintain the necessary equipment to separate the interruptible load from the firm power load. This equipment must meet the Company standards. The customer must also provide space for the separate metering of the interruptible load.

The interruptible load shall not be served from firm power circuits at any time. Violations of this provision will result in a charge of $10 per kilowatt per month applied to the interruptible load determined to have been served from firm power circuits.

(Continued on Sheet No. D-93.00)

STANDARD CONTRACT RIDER NO. *14* **DISTRIBUTED GENERATION**

APPLICABLE TO:	Residential Service Rate	Schedule Designation D1
	General Service Rate	Schedule Designation D3
	Large General Service Rate	Schedule Designation D4

AVAILABILITY OF SERVICE: Available to customers with on-site distributed generation desiring to operate in parallel with the Company's system and take service for their supplemental needs under one of the applicable tariffs listed above. The on-site generation capacity shall be no greater than 100 kW at a single location. Distributed generation resources include reciprocating engine generator sets, small turbine-generators, fuel cells~~,~~ regenerative dynamometers and renewable resources.

PARALLEL OPERATION: The customer must meet the interconnection requirements of the Company specified in "The Michigan Electric Utility Generator Interconnection Requirements" as approved by the Commission, and must enter into an Interconnection and Operating Agreement with the Company before parallel operation will be permitted. Operating in parallel with the Company's system without written approval by the Company of the interconnection and any subsequent changes to the interconnection will make the customer subject to disconnection.

The customer is advised to consult its insurers and insurance policies regarding the existence of coverage for on-site distributed generation resources. Homeowners' policies and insurers may afford varying degrees of coverage for this exposure, or may exclude it altogether. This statement is not to be viewed as the rendering of advice regarding the customer's insurance coverage.

RATES: The customer shall pay all direct costs of controlling and protective equipment necessitated by the presence of a source of power on his premises and costs to comply with the Guidelines.

Sell-Back Energy Rate:
For customers with a standard energy meter, the Company's monthly average top incremental cost of power will be applied to all kilowatt-hours delivered to the Company's system.

For customers with a time-of-day meter, the Company's average monthly top incremental cost of power for each time-of-day period will be applied to all kilowatt-hours delivered to the Company's system during that time-of-day period.

For customers with an interval meter, the Company's top incremental cost for each hour will be applied to all kilowatt-hours delivered to the Company's system during that hour.

METERING REQUIREMENTS: The Company will install separate metering for energy sold by the Company to the customer and for energy sold-back to the Company by the customer. The Company will, at the customer's request, upgrade the sell-back meter to either a time-of-day or interval meter, but the incremental cost of such upgrade is the responsibility of the customer.

CONTRACT TERM: Open order, terminable on three day's written notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

STANDARD CONTRACT RIDER NO. 16 **NET METERING FOR RENEWABLE RESOURCE ON-SITE POWER PRODUCING FACILITIES**

AVAILABILITY:

This rider is available on a first-generating first-served basis to electric customers operating on-site generation which satisfies the Renewable Resource eligibility requirements set forth below. This rider attaches to any metered tariff excluding riders. The total capacity contracted under this rider from systems with nameplate capacities of 20 kW or less shall be limited to 0.005 (0.5%) of the Company's system peak for the previous year as defined on page 401b of MPSC Form P-521. The total capacity contracted under this rider from systems with nameplate capacities greater than 20 kW but not greater than 150 kW shall be limited to 0.0025 (.25%) of the Company's system peak for the previous year as defined on page 401b of MPSC Form P-521. The total capacity contracted under this rider from systems with nameplate capacities greater than 150 kW but not greater than 550 kW shall be limited to 0.0025 (.25%) of the Company's system peak for the previous year as defined on page 401b of MPSC Form P-521.

This Rider is available only to customers participating in this Rider prior to May 9, 2019. A customer is "participating" if the customer has a completed application for service under this Rider pending before the utility prior to May 9, 2019. A customer who has an application filed with the utility before May 9, 2019 may still be allowed to participate in this Rider if the application is found deficient, provided the customer cures the deficiency within 60 days.

CHARACTER OF SERVICE:

As specified under the applicable Base Rate. The term Base Rate refers to the Rate Schedule under which the Customer takes service and that this Rider is associated with.

ELIGIBLE ELECTRIC GENERATING UNITS:

A. Eligible Technologies:

A methane digester or any renewable energy system as defined in section 11(k) of 2008 PA 295, MCL 460.1011(k) is an eligible technology. "Renewable energy system" means a facility, electricity generation system, or set of electricity generation systems that use 1 or more of the following renewable energy resources to generate electricity. Renewable energy resources include biomass, solar and solar thermal energy, wind energy, kinetic energy of moving water, including all of the following: waves, tides, or currents, water released through a dam, geothermal energy, municipal solid waste and landfill gas produced by municipal solid waste. Renewable energy system does not include any of the following:

1. A hydroelectric pumped storage facility.
2. A hydroelectric facility that uses a dam constructed after October 6, 2008 unless the dam is a repair or replacement of a dam in existence on October 6, 2008 or an upgrade of a dam in existence on October 6, 2008 that increases its energy efficiency.
3. An incinerator unless the incinerator is a municipal solid waste incinerator as defined in section 11504 of the natural resources and environmental protection act, 1994 PA 451, MCL 324.11504, that was brought into service before October 6, 2008, including any of the following:
   a. Any upgrade of such an incinerator that increases energy efficiency.
   b. Any expansion of such an incinerator before the effective date of this act.
   c. Any expansion of such an incinerator on or after October 6, 2008 to an approximate design rated capacity of not more than 950 tons per day pursuant to the terms of a final request for proposals issued on or before October 1, 1986.

B. Generating Unit(s) Size Limitations:

1. The maximum size of a methane digester system at a single site is limited to 550 kW and the maximum size of an individual unit or combination of units utilizing another renewable technology is 150 kW.

(Continued on Sheet No. D-102.00)

STANDARD CONTRACT RIDER NO 18 — DISTRIBUTED GENERATION PROGRAM

AVAILABILITY:
This Rider can be attached to any metered tariff, excluding riders, unless otherwise noted on the applicable metered tariff. The Distributed Generation Program is offered as authorized by 2008 PA 295, as amended by 2016 PA 342, 1939 PA 3, as amended by 2016 PA 341, Section (6) (a) (14), and the Commission in Case No. U-20162.

The Distributed Generation Program is available for eligible Distributed Generation customers on and after May 9, 2019.

A customer participating in a net metering program approved by the Commission before May 9, 2019 shall have the option to take service under this tariff at the time service under the terms and conditions of the previous net metering program terminates in accordance with MCL 463.0183(1).

The Distributed Generation Program is voluntary and available on a first come, first served basis for new customer participants or existing customer participants increasing their aggregate generation. The combined net metering (Rider 16) and Distributed Generation Program size is equal to 1.0% of the Company's average instate peak load for Full- Service customers during the previous 5 calendar years. Within the Program capacity, 0.5% is reserved for Category 1 Distributed Generation customers, 0.25% is reserved for Category 2 Distributed Generation customers and 0.25% is reserved for Category 3 Distributed Generation customers. The Company shall notify the Commission upon the Program reaching capacity in any Category.

If an existing customer who participates on Rider 16 increases their aggregate generation following the effective date of this rider, then all generation on site will be subject to the terms and conditions of this tariff.

CHARACTER OF SERVICE:
As specified under the applicable Base Rate. The term Base Rate refers to the Rate Schedule under which the Customer takes service and that this Rider is associated with.

DISTRIBUTED GENERATION DEFINITIONS

(1) ***A Category 1 distributed generation customer has one or more Eligible Electric Generators with an aggregate nameplate capacity of 20 kW or less that use equipment certified by a nationally recognized testing laboratory to IEEE 1547-2018 testing standards and is in compliance with UL 1741-SA and located on the customer's premises and metered at a single point of contact.***

(2) ***A Category 2 distributed generation customer has one or more Eligible Electric Generators with an aggregate nameplate capacity greater than 20 kW but not more than 150 kW that use equipment certified by a nationally recognized testing laboratory to IEEE 1547-2018 testing standards and is in compliance with UL 1741-SA and located on the customer's premises and metered at a single point of contact.***

Continued on Sheet No. D-112.00)

(Continued from Sheet No. D-111.00)

STANDARD CONTRACT RIDER NO 18 (contd) ***DISTRIBUTED GENERATION PROGRAM***

(3) A Category 3 distributed generation customer has one or more methane digesters with an aggregate nameplate capacity greater than 150 kW but not more than 550 that use equipment certified by a nationally recognized testing laboratory to IEEE 1547-2018 testing standards and is in compliance with UL 1741-SA and located on the customer's premises and metered at a single point of contact.

(4) Eligible Electric Generator – a renewable energy system or a methane digester with a generation capacity limited to no more than 100% of the customer's electricity consumption for the previous 12 months and does not exceed the following:
a. For a renewable energy system, 150 kW of aggregate generation at a single
site b. For a methane digester, 550 kW of aggregate generation at a single site

(5) Inflow – the metered inflow delivered by the Company to the customer during the billing month or time-based pricing period.

(6) Outflow – the metered quantity of the customer's generation not used on site and exported to the utility during the billing month or time-based pricing period.

(7) Renewable Energy Resource – a resource that naturally replenishes over a human, not a geological, timeframe and that is ultimately derived from solar power, water power or wind power. Renewable energy resource does not include petroleum, nuclear, natural gas, or coal. A renewable energy resource comes from the sun or from thermal inertia of the earth and minimizes the output of toxic material in the conversion of the energy and includes, but is not limited to, all of the following:
(i) Biomass
(ii) Solar and solar thermal
energy (iii) Wind energy
(iv) Kinetic energy of moving water, including the
following: (a) waves, tides or currents
(b) water released through a dam
(v) Geothermal energy
(vi) Thermal energy produced from a geothermal heat
pump (vii) Any of the following cleaner energy resources:
(a) Municipal solid waste, including the biogenic and anthropogenic
factions (b) Landfill gas produced by municipal solid waste
(c) Fuel that has been manufactured in whole or significant part from waste, including, but not limited to, municipal solid waste. Fuel that meets the requirements of this subparagraph includes, but is not limited to, material that is listed under 40 CFR 241.3(b) or 241.4(a) or for which a nonwaste determination is made by the United States Environmental Protection Agency pursuant to 40 CFR 241.3(c). Pet coke, hazardous waste, coal waste, or scrap tires are not fuel that meets the requirements of this subparagraph.

(Continued on Sheet No. D-113.00)

(Continued from Sheet No. D-112.00)

STANDARD CONTRACT RIDER NO 18 (contd) ***DISTRIBUTED GENERATION PROGRAM***

CUSTOMER ELIGIBILITY

In order to be eligible to participate in the Distributed Generation Program, customers must generate a portion or all of their own retail electricity requirements with an Eligible Electric Generator which utilizes a Renewable Energy Resource, as defined above.

A customer's eligibility to participate in the Distributed Generation Program is conditioned on the full satisfaction of any payment term or condition imposed on the customer by pre-existing contracts or tariffs with the Company, including those imposed by participation in the Distributed Generation Program, or those required by the interconnection of the customer's Eligible Electric Generator to the Company's distribution system.

CUSTOMER BILLING – CATEGORY 1, 2 AND 3 CUSTOMERS
Inflow

(1) Full Service Customers
The customer will be billed according to their retail rate schedule, plus surcharges, and Power Supply Cost Recovery (PSCR) Factor on metered Inflow for the billing period or time-based pricing period.

(2) Retail Open Access Customers
The customer will be billed as stated on the customer's Retail Open Access Rate Schedule on metered Inflow for the billing period or time based pricing period.

Outflow
The customer will be credited on Outflow for the billing period or time-based pricing period. The credit shall be applied to the current billing month and shall be used to offset power supply and PSCR charges on that bill. The credit shall not offset any delivery charges or other surcharges. Any excess credit not used will be carried forward to subsequent billing periods. Unused Outflow Credit from previous months will be applied to the current billing month, if applicable, to offset the power supply component and PSCR components on the customer's bill. Outflow Credit is nontransferrable.

(1) Full Service Customers
Power Supply Credit for Outflow:

Customers will be credited for each kWh of Outflow according to the non-transmission power supply rates shown below.

(Continued on Sheet No. D-114.00)

(Continued from Sheet No. D-113.00)

STANDARD CONTRACT RIDER NO 18 (contd) DISTRIBUTED GENERATION PROGRAM

Rate Schedule	Outflow Credit $ per kWh			
Residential				
D1/D1.6 Residential	First 17 kWh per Day: $0.07477	Excess: $0.09111		
D1.1 Int. Air	Summer: $0.06323	Winter: $0.03672		
D1.2 Time-of-Day	Summer On-Peak: $0.16142	Summer Off-Peak: $0.04912	Winter On-Peak: $0.13514	Winter Off-Peak: $0.04689
D1.7 Time-of-Day	Summer On-Peak: $0.12508	Summer Off-Peak: $0.03530	Winter On-Peak: $0.04885	Winter Off-Peak: $0.03642
D1.8 Dynamic Peak Pricing	Critical Peak: $0.94085	On-Peak: $0.13908	Mid-Peak: $0.07732	Off-Peak: $0.04026
D1.9 Elec. Vehicle	On-Peak: $0.16004	Off-Peak: $0.03315		
D2 Elec Space Heat	Summer First 17 kWh per Day: $0.07612	Summer Excess: $0.09246	Winter First 20 kWh per Day: $0.06055	Winter Excess: $0.04689
D5 Water Heat	All kWh: $0.03864			
Secondary				
D1.1 Int. Air	Summer: $0.06895	Winter: $0.04095		
D1.7 Time-of-Day	Summer On-Peak: $0.04784	Summer Off-Peak: $0.03384	Winter On-Peak: $0.03734	Winter Off-Peak: $0.03734
D1.8 Dynamic Peak Pricing	Critical Peak: $0.89282	On-Peak: $0.13725	Mid-Peak: $0.07725	Off-Peak: $0.04225
D1.9 Elec. Vehicle	On-Peak: $0.16132	Off-Peak: $0.03443		
D3 General Service	All kWh: $0.07150			
D3.2 Secondary Education	All kWh: $0.06228			
D4 Large General Service	First 200 kWh per kW: $0.04384	Excess: $0.03384		
D5 Water Heat	All kWh: $0.03886			
E1.1 Eng. St. Ltg.	All kWh: $0.04672			

(Continued on Sheet No. D-115.00)

M.P.S.C. No. 1 - Electric
DTE Electric Company
(Implementation of Rider 18)

Original Sheet No. D-114.00

(Continued from Sheet No. D-114.00)

STANDARD CONTRACT RIDER NO 18 (contd) ***DISTRIBUTED GENERATION PROGRAM***

Rate Schedule	***Outflow Credit $ per kWh***			
Primary				
D11 Primary Supply	***Demand:***	***On-Peak:***	***Off-Peak:***	
Primary	***$13.61 per kW***	***$0.043387***	***$0.033387***	
Subtransmission	***$13.03 per kW***	***$0.042194***	***$0.032194***	
Transmission	***$12.75 per kW***	***$0.041372***	***$0.031372***	
D6.2 Primary Educational Institution	***Demand:***	***On-Peak:***	***Off-Peak:***	
Primary	***$13.11 per kW***	***$0.04112***	***$0.03812***	
Subtransmission	***$12.56 per kW***	***$0.03982***	***$0.03682***	
Transmission	***$12.29 per kW***	***$0.03893***	***$0.03593***	
D10 All Electric School	***Summer: $0.07288***	***Winter: $0.05487***		

(2) Retail Open Access Customers

The Outflow Credit will be determined by the Retail Service Supplier.

APPLICATION FOR SERVICE

In order to participate in the Distributed Generation Program, a customer shall submit completed Interconnection and Distributed Generation Program Applications, including the application fee of $50 to the Company.

The Distributed Generation Program application fee is waived if the customer is transitioning from the Net Metering Program.

If a customer does not act or correspond on an application for over 6 months, when some action is required by the customer, the application may voided by the Company.

(Continued on Sheet No. D-116.00)

(Continued from Sheet No. D-115.00)

STANDARD CONTRACT RIDER NO 18 (contd) ***DISTRIBUTED GENERATION PROGRAM***

GENERATOR REQUIREMENTS

The Eligible Electric Generator(s) must be located on the customer's premises, serving only the customer's premises and must be intended primarily to offset a portion or all of the customer's requirement for electricity.

Systems will be limited in size, not to exceed the Customer's self-service needs of the Rate Schedule to which this Rider is attached. The customer's requirement for electricity shall be determined by one of the following methods:

(1) The customer's annual energy usage, measured in kWh, during the previous 12-month period

(2) In instances where complete and correct data is not available or where the customer is making changes on-site that will affect total usage, the Company and the customer shall mutually agree on a method to determine the customer's annual electric requirement

The customer is required to provide the Company with a capacity rating in kW of the generating unit and a projected monthly and annual Kilowatt-hour output of the generating unit, along with a one-line of system and site plan when completing the Company's Distributed Generation Program Application.

The customer need not be the owner or operator of the eligible generation equipment, but is ultimately responsible for ensuring compliance with all technical, engineering and operational requirements suitable for the Company's distribution system.

GENERATOR INTERCONNECTION REQUIREMENTS

The requirements for interconnecting a generator with the Company's facilities are contained in Rule B8., Electric Interconnection and Distributed Generation Standards, the Michigan Electric Utility Generator Interconnection Requirements and the Company's Generator Interconnection Supplement to Michigan Electric Utility Generator Interconnection Requirements. All such interconnection requirements must be met prior to the effective date of a customer's participation in the Distributed Generation Program. The customer must sign an Interconnection and Operating Agreement with the Company and fulfill all requirements as specified in the Agreement. The customer shall pay actual interconnection costs associated with participating in the Distributed Generation Program, subject to limits established by the Michigan Public Service Commission.

The Company must approve in writing any subsequent changes in the interconnection configuration before such changes are allowed. Operating in parallel with the Company's system without the Company's written approval of the interconnection and written approval of any subsequent changes to the interconnection will subject the Customer's equipment to disconnection.

(Continued on Sheet No. D-117.00)

(Continued from Sheet No. D-116.00)

STANDARD CONTRACT RIDER NO 18 (contd) ***DISTRIBUTED GENERATION PROGRAM***

METERING REQUIREMENTS

Metering requirements shall be specified by the Company, as detailed below. All metering must be capable of recording inflow and outflow and all parameters metered on the customer's otherwise applicable retail rate schedule, for both Full Service and Retail Open Access customers.

DISTRIBUTION LINE EXTENSION AND/OR EXTRAORDINARY FACILITIES

The Company reserves the right to make special contractual arrangements with Distributed Generation Program customers whose utility service requires investment in electric facilities, as authorized by the Company's Standard Contract Rider No. 2, Special Purpose Facilities, Rule C1, Character of Service, and Rule C6., Distribution Systems, Line Extensions and Service Connections, as set out in the Company's Electric Rate Book. The Company further reserves the right to condition a customer's participation in the Distributed Generation Program on a satisfactory completion of any such contractual requirements.

CUSTOMER TERMINATION FROM THE DISTRIBUTED GENERATION PROGRAM

A participating customer may terminate participation in the Company's Distributed Generation Program at any time for any reason on sixty days' notice. In the event that a customer who terminates participation in the Distributed Generation Program wishes to re-enroll, that customer must reapply as a new program participant, subject to program size limitations, application queue and application fees.

The Company may terminate a customer from the Distributed Generation Program if the customer fails to maintain the eligibility requirements, fails to comply with the terms of the interconnection and parallel operating agreement, or if the customer's facilities are determined not to be in compliance with technical, engineering, or operational requirements suitable for the Company's distribution system. The Company will provide sixty days' notice to the customer prior to termination from the Distributed Generation Program, except in situations the Company deems dangerous or hazardous. Such notice will include the reason(s) for termination.

Upon customer termination from the Distributed Generation Program, any existing Outflow credit on the customer's account will be applied to the power supply component and PSCR components of the customer's future bills for customers who remain in the residence. Outflow credit will be refunded to customers who do not remain in the residence. Distributed Generation Program credit is non-transferrable.

COMPANY TERMINATION OF THE DISTRIBUTED GENERATION PROGRAM

Company termination of the Distributed Generation Program may occur upon receipt of Commission approval.

Upon customer termination from the Distributed Generation Program, any existing Outflow credit on the customer's account will be applied to the power supply component and PSCR components of the customer's future bills for customers who remain in the residence. Outflow credit will be refunded to customers who do not remain in the residence. Distributed Generation Program credit is non-transferrable.

(Continued on Sheet No. D-118.00)

(Continued from Sheet No. D-117.00)

STANDARD CONTRACT RIDER NO 18 (contd) ***DISTRIBUTED GENERATION PROGRAM***

DISTRIBUTED GENERATON 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 Company's status report shall maintain customer confidentiality.

RENEWABLE ENERGY CREDITS

Renewable Energy Credits (RECs) are owned by the customer. The Company may purchase Renewable Energy Credits from participating Distributed Generation Program customers who are willing to sell RECs generated if the customer has a generator meter in place to accurately measure and verify generator output. REC certification costs are the responsibility of the customer.

The Company will enter into a separate agreement with the customer for the purchase of any RECs.

(Continued from Sheet No. E-6.00)

RETAIL ACCESS SERVICE RIDER – RIDER EC2 (Contd.)

E2 TERMS AND CONDITIONS OF SERVICE (Contd.)

E2.6.3 Multiple Meters at Residential Locations

Existing groupings of multiple meters into accounts at a location will be maintained in setting up new retail access accounts.

E2.7 Meter Reading

A All Customers with Advanced Electric Meters shall have meter reading accomplished through a secure communication network to provide DTE Electric the metering data necessary to bill the customer and conform to required metering accuracy. ***Regardless of meter type, DTE Electric shall provide the Alternative Electric Supplier and the Customer with reasonable access to timely, accurate, and complete meter data necessary for delivery, settlement, and billing of energy and electricity services in usable computer form and equivalent to DTE Electric's ability to access such data, and without unreasonable delay***, once the Customer is enrolled, without any further documentation or permission from the Customer.

DTE Electric shall inform the Alternative Electric Supplier and the Customer of any corrections made under Section E2.8 and shall provide such corrections at the same time that DTE corrects its own meter data.

Prior to a Customer being enrolled and with the Customer's permission, which may be either in writing or in electronic form, upon the Customer's request DTE Electric shall provide the Alternative Electric Supplier and Customer with reasonable access to accurate and complete historical meter data, or shall provide the requested data itself, in usable computer form equivalent to DTE's ability to access such data and without unreasonable delay.

B The switch of a Customer's account from one supplier to another will normally take place on the scheduled meter reading date for that Customer (the Effective Date) and be based on the reading made that same day. If an actual meter reading is not made on the Effective Date, DTE Electric will read the meter within five (5) business days of the date in which DTE Electric determines that the scheduled actual meter reading has not occurred. The meter reading on the Effective Date will be determined on a pro-rated basis based on the actual meter reading. DTE Electric's failure to read meters in the time frames noted, through no fault of the Customer, shall not result in penalties of any type to the Customer. Except for actions outside the scope of DTE Electric's control and storms or other events or occurrences that render the reading of meters physically impossible, customer's bills for DTE Electric distribution services will be reduced by 1/30 for each day DTE Electric meter reads are late past a three-day grace period.

E2.8 Meter Errors

Billing where metering errors and malfunctions have taken place shall be performed as follows:

A For Customers without Advanced Electric Meters where metered data is not available due to metering errors, malfunctions, or otherwise, the usage will be estimated using the procedures ***pursuant to Section C4.5 (B) and (C)***~~.~~

B For Customers with Advanced Electric Meters where metered data is not available due to metering errors, malfunctions, or otherwise, the usage will be estimated using the available historical data for the Customer.

(Continued from Sheet No. E-18.00)

RETAIL ACCESS SERVICE RIDER – RIDER EC2 (Contd.)

E*16*.*6* A supplier must allow the Staff of the Commission an opportunity to review and comment on its residential contract(s) and residential marketing material at least five business days before the Supplier intends to use these contract(s) and marketing material in the marketplace.

MARKETER SECTION

E1*7* REAL POWER LOSSES

The Marketer used by the Alternative Electric Supplier is responsible for replacing losses associated with the delivery of power to the Customer's meter. The amount of Power delivered by DTE Electric on the DTE Electric Distribution System to the Customer's meter shall be adjusted using the following real power loss factors for distribution service:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Secondary	10.88%	11.95%	12.01%	10.23%
4.8/13.2 kV	6.61%	7.13%	7.37%	6.31%
24kV/41.6 kV	1.86%	2.09%	2.34%	1.90%
120 kV and above	0.55%	0.57%	0.57%	0.55%

Marketers must schedule and supply an amount of Power equal to its Customers' hourly usage x (1 + D%) to account for losses on the DTE Electric Distribution System, where D% is the applicable loss factor from the table above.

E*18* HOURLY USAGE DATA TO SUPPORT MISO SETTLEMENT

E*18*.1 Meter Data Management Agent

At the option of the Marketer, DTE Electric will act as their Meter Data Management Agent (MDMA) for their customer loads within DTE Electric's service area. The Marketer is under no obligation to take this service from DTE Electric.

If the Marketer takes MDMA service from DTE Electric, then DTE Electric shall provide the Marketer with the same data it reports to MISO at the same time it reports such data to MISO and in usable computer form. If DTE subsequently corrects the data it reports to MISO, then DTE Electric shall provide the corrected data to the Marketer at the same time and shall identify which data, including hourly meter readings, are being corrected.

E18.2 Hourly Usage Data for Customers With Advanced Electric or AMI Meter Reads *or Other Metering with Available Hourly Integrated Data*

Hourly usage will be the customer's actual measured usage for each hour increment as recorded by the Advanced Electric or AMI meter ***or other meter***.

(Continued on Sheet No. E-20.00)

(Continued from Sheet No. E-19.00)

RETAIL ACCESS SERVICE RIDER – RIDER EC2 (Contd.)

E*18*   HOURLY USAGE DATA TO SUPPORT MISO SETTLEMENT (contd.)

E*18*.3 Hourly Usage Data for Customers Without Advanced Electric or AMI Meter Reads *or Other Metering with Available Hourly Integrated Data*

Hourly usage data for customers without Advanced Electric or AMI meter reads ***or other metering with available hourly integrated data*** will be determined ***in the same manner as for full service customers without such metering, including*** through the use of CPNode profiles. For each CPNode, profiles are developed based on 12 months of historical hourly usage and temperature data to determine the load in kWh for every MW of enrolled capacity.

Residential customers electing to opt out of AMI metering installation ***and without other metering with available hourly integrated data*** will have ***hourly usage data determined in the same manner as for full service residential customers without such metering, including*** profiled data used for MISO energy market settlement.

Michigan Public Service Commission MPSC Case No.: U-20162
DTE Electric Company ATTACHMENT C
Capacity Charge Calculation
FOR ORDER

	Total Electric	
CAPACITY COSTS DETERMINATION		
Net Production Costs Rev. Req.	$ 3,130,678	
Proj 2017 Energy Sales Rev Net of Fuel costs	$ (584,478)	
Less Fuel	$ (1,086,201)	
Less MISO Energy in PP	$ (47,395)	
Less Other Energy in PP	$ (156,542)	
Less Variable O&M	$ (11,271)	
Capacity Revenue Requirement	$ 1,244,791	
U-18248 Capacity Charge Demand	12,158	MW
Capacity Charge /MW-Year	$ 102,385	
Capacity Charge /MW-Day	$ 280.51	

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-20162

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on May 2, 2019 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna Brown

Subscribed and sworn to before me
this 2nd day of May 2019.

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

Service List for Case: U-20162

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