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 **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-21389

At the March 1, 2024 meeting of the Michigan Public Service Commission in Lansing,

Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Katherine L. Peretick, Commissioner
Hon. Alessandra R. Carreon, Commissioner

ORDER

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I. PROCEDURAL HISTORY

On May 1, 2023, Consumers Energy Company (Consumers) filed an application requesting authority to increase its retail rates for the generation and distribution of electricity by approximately $216 million. Application, p. 2. Consumers also requested other forms of regulatory relief including miscellaneous accounting authority. The company is currently providing service pursuant to rates established by the January 19, 2023 order in Case No. U-21224 (January 19 order) which approved a settlement agreement.[1] The projected revenue deficiency was later reduced by Consumers to $170.8 million. *See*, 4 Tr 650-651; Revised Exhibits A-186, A-191.

According to Consumers, 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 ending February 28, 2025. In its application, the company stated that the rate increase is necessary to recover ongoing investments in generation and distribution assets, ongoing investments related to safety and legal compliance, ongoing investments in enhanced technology, increased operations and maintenance (O&M) expenditures, and increased financing costs. Application, pp. 2-3. The company also seeks rate design and tariff changes. Consumers proposed a return on equity (ROE) of 10.25%, with an overall rate of return (ROR) on total rate base of 6.11%, and a 51.50% common equity ratio. Application, p. 7. Consumers' projected rate base for the test year in its initial filing was approximately $14.4 billion.

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[1] Consumers' last contested rate case was addressed in the December 22, 2021 order in Case No. U-20963 (December 22 order).

On May 26, 2023, Administrative Law Judge Sally L. Wallace (ALJ) conducted a prehearing conference. The ALJ acknowledged the notice of intervention filed by the Michigan Department of Attorney General (Attorney General), and granted petitions to intervene filed by the Association of Businesses Advocating Tariff Equity (ABATE); Energy Michigan, Inc. (Energy Michigan); The Kroger Co. (Kroger); Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (collectively, MNSC); Residential Customer Group (RCG); Great Lakes Renewable Energy Association (GLREA); Michigan Cable Telecommunications Association (MCTA); Hemlock Semiconductor Operations LLC (Hemlock); Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United (collectively, MEIBC/IEI/United); Environmental Law and Policy Center, Ecology Center, Union of Concerned Scientists, and Vote Solar (collectively, Clean Energy Organizations or CEOs); ChargePoint, Inc. (ChargePoint); Michigan Municipal Association for Utility Issues (MI-MAUI); Foundry Association of Michigan; Michigan Electric Transmission Company (METC); Urban Core Collective (UCC); and Walmart, Inc. (Walmart). Consumers and the Commission Staff (Staff) also participated. A schedule for the proceeding was established by the ALJ in accordance with the 10-month schedule required by MCL 460.6a(5).

On May 30, 2023, the ALJ adopted a protective order.

Direct testimony was filed by the Staff and intervenors on August 29, 2023, and rebuttal testimony was filed on September 19, 2023. Evidentiary hearings were held on October 9-12, 2023, where cross-examination took place. Timely initial and reply briefs were filed.

The ALJ issued a Proposal for Decision (PFD) on December 21, 2023. On January 10, 2024, Consumers, the Staff, the Attorney General, the CEOs, ABATE, MEIBC/IEI/United, UCC, Hemlock, and MI-MAUI filed exceptions. On January 23, 2024, Consumers, the Staff, the

Attorney General, ABATE, MNSC, MEIBC/IEI/United, MI-MAUI, UCC, Hemlock, and the CEOs filed replies to exceptions.

At the opening of the PFD, the ALJ states that "[i]n light of the time constraints of a 10-month rate case, any costs or programs that were disputed by Staff or intervenors in direct testimony, and that were subsequently conceded in the company's rebuttal, will generally not be discussed further in this PFD." PFD, p. 4.[2] The ALJ also provided a description of the topics covered by each witness. *See*, PFD, pp. 4-18.

The record consists of 4,274 pages of transcript and 648 exhibits (inclusive of schedules) received into evidence, some of which were filed confidentially. The Commission also received 15 comments in the public comment section of the e-docket.

II. LEGAL STANDARDS

Before addressing the issues, the ALJ provided the following review of the legal standards applicable to this case:

> The Commission applies the preponderance of the evidence standard when making findings of fact or weighing conflicting evidence. The Commission is required to set rates that are just and reasonable when exercising its ratemaking authority.
>
> The rate-making process necessarily "involves a balancing of the investor and the consumer interests." A public utility is constitutionally protected from being limited to rates that are so inadequate as to be confiscatory. One of the factors relevant to the rate-setting process is the return a utility's investors may reasonably expect given the risk profile of public utilities as business enterprises. The Commission has acknowledged that rates should be set so as to balance the interests of customers and shareholders such that the utility has "the opportunity to earn a reasonable return on its investments."
>
> In considering whether rates are just and reasonable, it is the result reached, and not the methods employed, that is controlling. Further, the Commission has broad

[2] The headings in this order generally reflect the headings used in the PFD.

> discretion in determining the appropriate amount of investment on which a return will be computed. For example, in discussing the Commission's predecessor agency, the Michigan Railroad Commission, the Michigan Supreme Court has held that "[w]hat return a public utility shall be entitled to earn upon its invested capital and what items shall be considered as properly going to make up the sum total of that invested capital are questions of fact for the determination of the commission[.]" Additionally, ratemaking is a legislative function, and the Commission is not bound by any particular method or formula in the exercise [of] this legislative function.

PFD, pp. 18-19 (footnotes omitted). The ALJ indicated that she would generally look to precedent in making her decisions.

No party filed exceptions to the ALJ's description of the applicable legal standards.

In her exceptions, the Attorney General states that the ALJ failed to address the burden of proof. Attorney General's exceptions, p. 3. The Attorney General notes that in cases before the Commission, case law holds that "the utility bears the burden of proof by a preponderance of evidence to demonstrate that its proposals are just and reasonable" and the plaintiff retains the burden of proof throughout a contested proceeding. *Id*. (citations omitted). No replies were filed.

III. TEST YEAR

In developing its rates for this proceeding, Consumers relied on a projected test year from March 1, 2024, to February 28, 2025 (test year) based, in part, on the 2022 historical year adjusted for known and measurable changes. ABATE and the Attorney General objected to the use of the fully projected test year (as opposed to an historical test year) on grounds that it increases the complexity and frequency of rate cases, disincentivizes cost containment, and introduces an excess of information that cannot be known with adequate certainty. 4 Tr 2725-2736, 3109-3113. ABATE also proposed an earnings sharing mechanism (ESM) as a vehicle for refunding over-earnings to customers, and the Attorney General objected to the 14-month bridge period for its length and the fact that it falls outside of a calendar year. 4 Tr 2942. The Staff noted that MCL

460.6a(1) permits a utility to develop its rate request based on projected costs but does not require the Commission to approve those projections. Consumers countered that it had provided extensive evidence in support of each investment, and that it has a statutory right to have its rates based on a fully projected test year.

The ALJ agreed with the Staff and found that projections may be rejected. PFD, p. 26. She further found that, while the ESM is designed to operate prospectively and does not constitute retroactive ratemaking, it should again be rejected as it was in the most recent rate cases filed by DTE Electric Company (DTE Electric), Case Nos. U-20836 and U-21297. PFD, p. 27. The ALJ found that "an ESM does not address the underlying problem of the company's inadequate and often overstated projections of test year expenditures." PFD, pp. 27-28. She further found that the ESM does not address the utility's "unrelenting capitalization programs . . . nor does the mechanism address how to restrain the utility from simply spending money to avoid having to make any refunds were the ESM to be approved." *Id.*, p. 28. She reiterated that projections that are not adequately supported on the record may be rejected in favor of costs based on historical amounts, and the Commission may apply the used and useful concept on a case-by-case basis. The ALJ noted that she used the applicant's projected test year amounts as her starting point for deciding issues. Finally, the ALJ found that "issues concerning the company's presentation are more appropriately addressed as part of the [rate case] filing requirements." PFD, p. 29.

In exceptions, ABATE argues that the Commission should adopt the ESM because "it will act to help ensure that Consumers does not cut operational and maintenance spending just to boost revenue to shareholders." ABATE's exceptions, p. 2. ABATE argues that the ALJ's concern that the company would simply increase capital expenditures is speculative and, in any case, Consumers' ability to accelerate capital spending on short notice is limited. ABATE maintains that denying the ESM proposal "would simply concede all earnings in excess of the projected costs the Company presented here which could otherwise be returned to customers." *Id*.

In exceptions, Consumers states that the ALJ's legal conclusions on the test year issue are mistaken, but the company considers them moot because "the PFD resolved the ultimate issues consistent with the Company's position" and thus it does not except. Consumers' exceptions, p. 6.

In replies to exceptions, the Staff contends that it is the company that has arrived at mistaken legal conclusions, as shown by the plain language of the relevant statutes and case law. Staff's replies to exceptions, p. 29.

The ALJ correctly refers to the Commission's previous findings regarding the ESM as well as the projected test year. *See*, November 18, 2022 order in Case No. U-20836 (November 18 order), p. 361, and December 1, 2023 order in Case No. U-21297 (December 1 order), pp. 291-292. Nothing in the instant record persuades the Commission to deviate from those prior rulings, and the Commission adopts the findings and recommendations of the ALJ.

IV. RATE BASE

Rate base consists of the capital invested in used and useful utility plant, less accumulated depreciation, plus the utility's working capital requirements. Consumers projected a total electric rate base of $14.4 billion, which was later revised to $13.8 billion. The Staff projected a total electric rate base of $13.73 billion.

A. Net Utility Plant

Net utility plant is comprised of plant held in service, plant held for future use, and construction work in progress (CWIP), less the depreciation reserve. Consumers' projected rate base capital amounts are divided into the following programs: Electric Distribution, Streetlighting, Generation, Information Technology (IT), Security, Electric Vehicles (EVs), Electric Operations Support (including Facilities), Fleet Services, Corporate, Customer Experience and Operations (CX&O), and Demand Response (DR). Exhibit A-12, Schedule B5.

1. Electric Distribution System Capital Expenditures

Consumers' distribution capital spending is further divided into: New Business, Reliability, Capacity, Demand Failures, Asset Relocations, and Electric Other; and these are, in turn, divided into numerous subprograms. Exhibit A-12, Schedule B5.7. The ALJ began her analysis of these proposed expenditures by stating that the PFD "only addresses specific areas where there are disputes." PFD, p. 31.

Consumers filed a general exception in which the company commits to working with the Commission to improve the reliability and resilience of the grid. Consumers states that "[a]t the funding levels requested in this case, Consumers Energy expects to improve on the SAIDI [system average interruption duration index] goals from the 2021 EDIIP [electric distribution infrastructure investment plan] to achieve 162 SAIDI minutes in 2025 and 151 SAIDI minutes in 2027." Consumers' exceptions, p. 7 (citing 4 Tr 360). Consumers states that it cannot achieve its goals if distribution system investment is reduced.

The Attorney General filed a general reply, arguing that "it took years of neglect and inattention for the distribution system to get to its current condition, and it will take time to correct. The investment amount that should be approved depends on the Company's ability to meet its evidentiary burden." Attorney General's replies to exceptions, p. 8. The Attorney General asks the Commission to consider the financial consequences for customers.

The Commission addresses Consumers' specific funding requests below.

a. High Voltage Distribution

Consumers' high voltage distribution (HVD) system is composed almost entirely of 46 kilovolt (kV) lines (and includes a small number of 69kV and 138kV lines), and transmits energy to the low voltage distribution (LVD) system. 4 Tr 1728-1731. The HVD system has 180 substations and 4,600 miles of lines, which connect to 1,100 LVD substations. Consumers had actual capital expenditures of $150.1 million in 2022 on the HVD system, and projects capital spending of $153.2 million for the 14-month bridge period of January 1, 2023, through February 28, 2024 (bridge period), and $173.7 million in the test year, on both planned (proactive) and emergent (reactive) programs. *Id.*; Exhibits A-116 through A-118.

The Staff argued that, in light of historical spending that ranges from $50 million in 2018 to $150 million in 2022, the bridge and test year period projections are excessive. Based on actual HVD spending for the first five months of 2023 of about $36 million (as indicated by Consumers in discovery), and adding a 10% escalator for each period, the Staff recommended projections of $110.9 million and $104.5 million for the bridge period and test year, respectively, which results in disallowances of $42.4 million for the bridge period and $69.1 million for the test year. 5 Tr 3857-3860. The Staff noted that its proposed test year amount includes a reduction to rate base capital expenditures of $53.29 million and a reduction to the proposed investment recovery mechanism (IRM) of $15.8 million. 5 Tr 3857-3860.

Consumers countered that the Staff's proposal is an across-the-board reduction which does not analyze the importance of individual programs. Consumers also argued that, in discovery responses regarding spending for the first five months of 2023, Consumers only provided information on its 25 largest HVD projects, thus the calculation is based on incomplete information. 4 Tr 1833. Consumers argued that it is actually on track to spend $164 million in the bridge period, and that it actually spent $58.59 million in the first six months of 2023. 4 Tr 1832-1833; Exhibit A-209.

The ALJ recommended that the Commission reject the proposed disallowance because the Staff's proposal is based on only the 25 largest HVD projects and not on total HVD spending. PFD, p. 35. She further noted that the first five months of 2023 may not be dispositive of the issue because spending may not be uniform over the entire bridge period.

In exceptions, the Staff argues that it is focusing on actual spending, and that the evidence gleaned from discovery shows that Consumers spent only about $36 million in the first five months of 2023. Staff's exceptions, pp. 1-2 (citing Exhibit S-11.2 and 5 Tr 3858). The Staff contends that the company never supported the increased amount and the projected costs are inflated.

In reply, Consumers argues that the Staff only looked at the first five months of 2023 and failed to analyze the detailed support that the company provided for its specific HVD projects. Consumers' replies to exceptions, p. 6 (citing 4 Tr 7125-1827). Consumers objects to cutting HVD expenditures by about one-third compared to 2021 and 2022 and argues that the evidence should not be ignored. The company also argues that the Staff incorrectly applied the information that was provided in discovery, noting that the Staff had only asked for information on projects that were completed, leaving out those that were in progress. The Staff then asked for amounts spent during the first five months of 2023 on the top 25 in-progress test year projects. Consumers contends that the Staff used the two answers to arrive at its proposed adjustments, but the amount for the first five months of 2023 used by the Staff did not represent total investments for that time period because only 25 of the in-progress projects were included. Consumers' replies to exceptions, p. 7. Consumers asserts that, using the full level of HVD expenditures for those five months shows that the company was on track to spend more in the bridge period than what it had requested. Consumers states that $22.8 million in spending on in-progress projects outside of the top 25 is left out of the Staff's calculation. *Id*., p. 9 (citing 4 Tr 1833). Consumers further argues that it is not reasonable to use simply the five months of 2023 as the sole basis for the bridge period and test year projections, when the company provided detailed evidence regarding planned projects in Exhibits A-118 and A-119. Consumers contends that it is focusing on improving reliability and it would be unreasonable to reduce HVD spending to $100 million annually when it was around $150 million in 2021 and 2022.

The Commission agrees with the ALJ that the Staff was not working with complete cost information when it proposed its adjustments. The Commission also agrees that the first five months of the bridge period alone may not provide the strongest basis for projecting the entire bridge and test year periods, particularly on the basis of incomplete information. The Commission adopts the findings and recommendations of the ALJ and, as it has in the past, again encourages Consumers to provide a complete and thorough evidentiary presentation with its rate case filing rather than relying on discovery as the avenue for presenting key evidence.

i. High Voltage Distribution Lines and Substations Capacity

This cost category addresses capacity and interconnection needs on the HVD system. Consumers projects capital expenditures of $35.7 million in the bridge period and $45.7 million in the test year. 4 Tr 1761-1769. These amounts are based on projections of 14 new interconnections in the bridge period and 13 new interconnections in the test year, and include amounts for procuring a certain number of required rights-of-way (ROWs) during those periods.

The Attorney General argued that the projections for both new interconnections and ROWs are excessive. The Attorney General calculated the average per-unit interconnection cost for the four years of 2018-2022 (excluding 2021 due to the low number of projects), adjusted for inflation, to be $269,848, based on an annual average of 10 interconnection projects. Based on this per-unit calculation, she recommended a disallowance for the test year of $7.3 million. 4 Tr 2967-2969; Exhibit A-139, line 119. For ROWs, the Attorney General recommended a disallowance of $8.3 million in the bridge period and $3.02 million in the test year, based on the three-year average of $4.82 million per ROW purchase for 2020-2022.

Consumers countered that the per-unit basis for costs ignores the fact that there is significant variation among projects, and the relevant time periods include just a few large projects that drive the cost increases. 4 Tr 1835.

The ALJ recommended that the Attorney General's proposed disallowances be rejected. PFD, p. 39. She found that the unit cost approach is not appropriate where there are relatively few projects and a subset of those (few) projects have high costs.

In exceptions, the Attorney General argues that Consumers has "proposed 13 projects for the projected test year at an average cost of $848,000, which is more than three times the average historical unit cost and nearly three times higher than the highest annual cost per project." Attorney General's exceptions, p. 5 (citing 4 Tr 2968). She contends that this is excessive and not backed by historical experience. The Attorney General argues that a multi-year average unit cost can provide a reliable basis for projections even where a few projects have higher costs, and she notes that an average incorporates previous high and low costs. The Attorney General urges the Commission to adopt a $7.3 million disallowance for the test year for new interconnections.

Turning to ROWs, the Attorney General notes that in the three-year period of 2020-2022 Consumers spent an annual average of $4.82 million on ROW purchases, and she argues that this provides a reasonable basis for the bridge and test year period projections. The Attorney General notes that her proposed disallowances are not adjusted for inflation because the ROW purchases are negotiated fees. Attorney General's exceptions, p. 7 (citing 4 Tr 2969). Regarding the ALJ's remarks about the impact of a few large projects, the Attorney General contends that the company failed to show that costs will increase to the extent forecasted by the company.

In reply, Consumers argues that its new interconnections cost projections are based on the details of identified projects and not simply averages, because there is a wide variance in the work that is required for each project, ranging from $10,000 to $5 million per project. Consumers' replies to exceptions, p. 11. Consumers maintains that several large projects are driving the costs in this category and an average is simply too simplistic. *Id*., pp. 11-12 (citing 4 Tr 1768-1769, 1835).

Turning to ROW purchases, Consumers states that its projections were based on historical costs for similar projects, but refined based on information regarding the actual projects to be undertaken. Consumers again notes that there are a few large ROW projects that are affecting the projected unit costs, which include projects in the areas of Houghton Lake, Coopersville, and Omer. Consumers' replies to exceptions, p. 13.

The Commission agrees with the ALJ that, while the unit cost approach is often useful, that is not always the case. Consumers adequately demonstrated that, in the instant case, these two cost categories contain a few large projects that reflect the variability of expenditures for new interconnections and ROW purchases. 4 Tr 1767-1771. The Commission adopts the findings and recommendations of the ALJ.

ii. Electric Other (Computers and Equipment)

This cost category addresses the need for such items as computers, system controls, and grid technologies. Consumers projected total bridge period spending of $9.1 million and test year spending of $8.9 million for the total Electric Other cost category. 4 Tr 1771-1772; Exhibit A-122.

The company noted that it spent $6 million in 2022 to implement the Scheduling Optimization tool, which is intended to ensure that the correct field work crew is on site at the correct time, and the company seeks recovery of this amount. 4 Tr 1772-1773. Consumers stated that this tool has increased productivity by 25% and reduced overtime by 30%, and thus the company projected that it will produce a savings of over $10 million in capital expenditures for 2023. 4 Tr 1773. For Computers and Equipment, inclusive of the Scheduling Optimization tool, Consumers seeks $6.27 million in historical costs, $595,000 for the bridge period, and $75,000 for the test year. 4 Tr 1773; Exhibit A-128, line 1.

The Attorney General noted that, in response to discovery, Consumers identified $15.4 million in capital expenditure reductions for 2023 and $18.8 million for 2024, as well as savings to O&M expenses of $2.8 million for 2022-2023 and $4.6 million for 2024-2025 resulting directly from use of the Scheduling Optimization tool; however, the Attorney General argues, the savings are spread across several programs and cannot be identified in the record. 4 Tr 2979-2980; Exhibit AG-1.9. For that reason, the Attorney General argued that bridge period capital expenditures should be reduced by $15.4 million and test year capital expenditures should be reduced by $3.4 million to reflect the forecasted savings.

Consumers countered that, though it did not include a line-item reduction, the projected savings were taken into account when cost projections for individual programs were made, thus the proposed disallowance would result in double-counting of the savings. 4 Tr 1841.

The ALJ recommended that the Commission adopt the Attorney General's proposed adjustments of $15.4 million for the bridge period and $3.4 million for the test year, finding that:

> it is indeed concerning that the company could not provide even one example of a project cost that was reduced due to the implementation of the Scheduling Optimization tool, although the savings Consumers projected are considerable. Time and again Consumers has justified new or expanded programs on grounds that costs are reduced now, or will be in the future, but those reductions are never quantified or traced to where the savings can be found and verified.

PFD, pp. 42-43 (emphasis in original).

In exceptions, Consumers argues that the ALJ appears to be requiring the company to show exactly where the expected savings associated with the Scheduling Optimization tool show up in the other exhibits, and this is "a requirement that has never been ordered by the Commission or shown to be practical given the numerous considerations that make up cost projections in a rate case filing." Consumers' exceptions, p. 30. The company asserts that this tool will help optimize crew scheduling, and its initial rollout has already increased field productivity by 25% and reduced overtime by 30%. Consumers notes that it typically does not itemize all of the factors that are expected to increase costs or reduce costs in its exhibits, but asserts that the savings associated with the use of this tool were applied across several programs in preparing cost projections and the PFD's recommendation will result in double counting of those savings. Consumers also maintains that it did provide an example of savings when it "indicated that the expected capital and O&M savings are due to increased field productivity and reduced scheduled overtime. See 4 TR 1773." Consumers' exceptions, p. 31. Finally, Consumers argues that any reduction to its projections should not exceed the total actual cost of the project, and Exhibit AG-1.9, p. 1, shows that the capital costs of the project through 2025 are projected at $9.6 million; thus, any disallowance should be limited to $9.6 million. *Id*., p. 32.

In reply, the Attorney General argues that Consumers failed to show that it incorporated any planned cost savings arising from use of the Scheduling Optimization tool in its case, either in capital expenditures or in O&M, and the company's argument is not credible. Attorney General's replies to exceptions, pp. 35-38. Noting that Consumers described savings associated with increased field productivity and reduced use of overtime, the Attorney General posits that "in the context of this rate case, savings should equate to dollars and the Company could not provide the dollars that were saved." *Id*., p. 37.

The Commission disagrees with the Attorney General and the ALJ and rejects the proposed disallowance. In Exhibit AG-1.9, p. 1, the company did provide benefits in dollars, and the chart shows that they significantly outweigh costs. Further, in its testimony, Consumers showed that it had analyzed the benefits of the Scheduling Optimization tool and quantified the percentage increases to productivity and reductions to overtime. 4 Tr 1771-1773, 1841. The Commission finds the quantification of the benefits reflected in the exhibit and in the testimony to be persuasive, and approves Consumers' request for $6.27 million in historical costs, $595,000 for the bridge period, and $75,000 for the test year for Computers and Equipment, inclusive of the Scheduling Optimization tool. 4 Tr 1772-1773; Exhibit A-128, line 1. As Consumers notes, the bridge period and test year amounts are lower than the five-year average for this subprogram (of $1.34 million), which no party disputed. 4 Tr 1773; Exhibit A-122, line 50.

iii. High Voltage Distribution Strategic Customers New Business

This cost category includes spending on connecting new large commercial and industrial (C&I) customers to the distribution grid. Consumers projected $21.8 million in bridge period and $31.8 million in test year spending, which covers both planned projects and potential projects that are not yet identified. 4 Tr 1791-1798. The test year amount includes $2.0 million for the Economic Development Site Readiness (EDSR) project, which is intended to make potential sites ready for connection though there is no identified customer. *Id*.

The Attorney General proposed a bridge period disallowance of $13.1 million connected to two projects which are still in negotiations plus $2.9 million for projects that are as yet unknown, and a test year disallowance of $29.8 million for three projects that are still in negotiations plus $2.0 million for the EDSR program, for a total of $31.8 million for the test year. 4 Tr 2971-2973. ABATE also proposed the latter $2.0 million disallowance for the EDSR program in the test year and the same $2.9 million disallowance for the bridge period for unknown projects. Consumers countered that timelines for requested connections can be very short and this work is not premature. The company noted that it has signed contracts for two of the projects, and that state and federal policy support the addition of industrial capacity in Michigan, making readiness an important factor. 4 Tr 1837-1839.

The ALJ found that "some disallowance for placeholder amounts and potential projects without signed contracts should be adopted[,]" however she did not recommend approval of the Attorney General's full disallowances. PFD p. 47. Finding that the record is unclear as to whether contracts have been signed related to the $2.9 million in the bridge period, she recommended that this amount be disallowed. She found that there is no contract associated with $6.113 million in the test year and made the same recommendation, and she found that the $2.0 million for the EDSR should be disallowed as well because these amounts are speculative, risky, and not tied to a specific customer or project. PFD, p. 48. She noted that reasonable and prudent costs may be included in a future rate case.

In exceptions, the Attorney General argues that her full proposed disallowances should be adopted because even projects that are under contract may be premature for rate base treatment, and Consumers may always recover reasonable and prudent costs in future rate cases. Attorney General's exceptions, p. 9.

In exceptions, Consumers argues that its proposed costs are reasonable and prudent. Regarding the $2.9 million for unidentified projects, Consumers contends that it is prudent to plan for emergent work that is likely to occur, and the company notes that in September 2023 (when rebuttal was filed) the company had several ongoing inquiries from new customers. Consumers contends that its rebuttal testimony showed that $2.18 million in spending had been identified and agreed to by the company. Consumers' exceptions, p. 11 (citing 4 Tr 1838).

Regarding the $2.0 million for the EDSR, Consumers argues that "the lead time needed to install a large, new dedicated customer substation and associated lines is often prohibitive for potential customers looking for a site where production can start as soon as possible. 4 TR 1798." Consumers' exceptions, p. 12. Consumers states that development trade groups cite the need for sites that are ready for development and this projected expenditure will allow Consumers to make preparations before a customer commits. The company argues that Michigan needs to be able to signal that it is open to new business and can readily provide attractive sites for potential new customers.

Regarding the $6.11 million in test year expenditures for the substation that does not have a signed contract, Consumers states that this project involves the expansion of an existing customer's facility and the ability to provide separate service. Consumers' exceptions, p. 14 (citing Exhibit A-119, p. 8, Exhibit A-210, pp. 34-44, and 4 Tr 1793, 1837). Consumers states that it supported the projected spending which involves procuring large transformers and easements, completing the design, and completing the construction. The company argues that it is not premature.

In reply, ABATE argues that Consumers makes general assertions about the economy but does not tie the costs to any actual projects, making the requests essentially for contingency amounts. ABATE's replies to exceptions, p. 6.

In reply, the Attorney General argues that, although Consumers updated its case to indicate that it has entered into agreements or negotiations, it is not clear whether these will result in contracts for actual work. The Attorney General contends that these costs are for emergent and speculative work, thus representing simply placeholders, and that it is unreasonable to ask ratepayers to underwrite the risk associated with pre-developing a site that may not be selected by a developer during the relevant time period. She argues that site development that is taken on without a known customer is not required under Consumers' duty to provide reliable service. Attorney General's replies to exceptions, p. 20.

In reply, Consumers argues that where contracts have been signed the work is not premature, referring to contracts signed for a project in southern Michigan and another in northwest Michigan. Consumers' replies to exceptions, p. 15 (citing 4 Tr 1837).

The Commission finds that the ALJ struck a fair balance between guarding against speculative investments and funding necessary work. The Commission rejects the full disallowances proposed by the Attorney General, but adopts the findings and recommendations of the ALJ to partially disallow the specific amounts associated with unidentified projects, the EDSR, and the project lacking a signed contract. The Commission finds that this decision accounts for the potentially long lead time for receipt of inventory that is of concern to the company, but also recognizes the ability of the company to recover reasonable and prudent amounts in future rate cases when the projects have been identified.

iv. High Voltage Distribution Lines and Substations Rehabilitation

This program addresses planned and emergent repair and replacement of 46kV and 138kV lines and substation equipment. Consumers projected capital spending of $33.71 million in the bridge period and $37.05 million in the test year. 4 Tr 1814-1822.

The Attorney General recommended disallowances of $3.84 million for the bridge period and $8.99 million for the test year for the HVD Substation Rehabilitation subprogram, arguing that the company failed to explain the need for the increases reflected in the projections. The Attorney General based her recommendation on the use of the three-year 2018-2020 average of $17.2 million for this subprogram adjusted for inflation. 4 Tr 2974-2975. ABATE recommended disallowances for both the HVD Substation Rehabilitation program and the HVD Switch Replacement Projects Identified by Inspection (Switch Replacements) subprograms. ABATE recommended reductions of $1.88 million for the bridge period and $6.23 million for the test year for Substation Rehabilitations, and $1.33 million for the bridge period and $1.05 million for the test year for Switch Replacements. 4 Tr 2818. ABATE argued that these subprograms do not have identified projects at this time for these amounts, making the amounts speculative.

Consumers countered that this cost category contains a broad blend of proactive and reactive investments, and that the costs reflect some large substation rebuilds and transformer projects that were approved in 2021. 4 Tr 1822.

The ALJ found that ABATE’s proposed disallowances are reasonable and recommended that the Commission adopt them. PFD, pp. 51-52. The ALJ found that ABATE showed that the projects are unidentified and uncertain, and noted that the disallowances are small compared to total spending. The ALJ recommended adoption of the disallowances for Substation

Rehabilitations and Switch Replacements, and noted that reasonable and prudent spending can be requested in future rate cases.

In exceptions, the Attorney General argues that the Substation Rehabilitation costs have increased significantly since 2021-2022 and Consumers did not provide sufficient explanation for the increase. She contends that her projection, which is based on the annual average spend for the three years of 2020-2022 adjusted for inflation, provides a reasonable basis for the disallowances in the bridge and test year periods. Attorney General's exceptions, p. 11 (citing 4 Tr 2975). The Attorney General notes that the ALJ recommended adoption of ABATE's proposed disallowances without explaining why the Attorney General's proposal was rejected. She also notes that the company described these costs as mostly reactionary but also included proactive projects in Exhibits A-118 and A-119, and at 4 Tr 1840. Attorney General's exceptions, p. 12.

In exceptions, Consumers argues that these costs support the repair and replacement of substation equipment that is about to fail through proactive work that can save outage minutes in comparison to the outage minutes associated with waiting for the actual failure. Consumers' exceptions, p. 16. Consumers argues that it uses historical replacement rates to make these projections based on the last five years of inspecting similar assets. *Id*., p. 17 (citing 4 Tr 1817-1818). The company contends that the ALJ fails to actually consider whether the forecasts are reasonable, and that this disallowance will result in delays which will hurt customers.

In reply to the Attorney General, Consumers argues that the proactive replacements are based on inspection results and the emergent spending is based on historic amounts. Consumers' replies to exceptions, p. 16 (citing 4 Tr 1818, 1822). The company states that its projections reflect the large substation rebuild projects and large transformer replacement projects that were previously approved by the Commission.

The Commission disagrees with the ALJ and finds that, while a disallowance is appropriate, the Attorney General's proposal is superior to ABATE's. ABATE proposes line-item disallowances to both Substation Rehabilitations and Switch Replacements based on the projects designated in Consumers' testimony as being currently unidentified. 4 Tr 2835 (citing 4 Tr 1793 and 1817) (Table 3 appears at 4 Tr 2818).[3] ABATE selected these line items because this type of work is identified through inspections, and thus the actual projects are not yet known. However, ABATE's proposal removes all funding. Conversely, the Attorney General's recommended disallowances of $3.84 million for the bridge period and $8.99 million for the test year are for the Substation Rehabilitation subprogram, and are based on the three-year 2018-2020 average of $17.2 million for this subprogram adjusted for inflation. 4 Tr 2974-2975. The Commission finds it likely that some of this proactive and emergent work will actually occur during the bridge period and test year. However, in light of the average presented by the Attorney General and the fact that the emergent work carries a degree of uncertainty, the Commission finds that the work is not likely to materialize at the rate that the company forecasts. *See*, 4 Tr 2974-2975. The Commission also finds Consumers' projection for Switch Replacements to be supported. 4 Tr 1742-1827, 1842. The Commission adopts the Attorney General's proposed disallowances for the Substation Rehabilitation subprogram for the bridge and test year periods.

b. Low Voltage Distribution

The LVD system includes over 94,000 miles of lines, with approximately 51,500 miles of primary overhead lines, 9,500 miles of primary underground lines, 30,000 miles of secondary

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[3] Though not explained in the testimony, ABATE's proposals are based on the amounts identified by the company in Exhibit A-118, p. 6, line 291, and Exhibit A-119, p. 1, lines 47 and 50, and p. 7, line 332.

overhead lines, 3,000 miles of secondary underground lines, and over 2,000 LVD circuits. 4 Tr 1860-1863. The ALJ states that the PFD only addresses costs in dispute. PFD, p. 52.

i. Low Voltage Distribution New Business

This cost category addresses the connection of customers to the distribution grid and contains several programs and subprograms which are discussed below.

LVD Lines New Business

This cost category addresses new LVD service connections for residential and smaller C&I customers. Consumers projected capital spending of $140.9 million in the bridge period and $108.7 million in the test year for this subprogram based on historic growth and home builders' projections. 4 Tr 1864-1866.

The Attorney General argued that projected bridge period spending is excessive based on factors including a 2023 Home Builders Association of Michigan (HBAM) news release and a 2023 IHS Markit report, both of which forecast declines in new housing starts in 2023 compared to 2022, for at least part of the year. 4 Tr 2946-2948. The Attorney General supported a disallowance of $18.2 million for the bridge period based on fewer projected housing units. The Attorney General did not object to the projected units for the test year, but did object to the per-unit cost, noting that it increased by 51% between 2019 and 2022. 4 Tr 2949-2950. Thus, the Attorney General also recommended a 3% reduction to the test year projection (a $3.28 million disallowance) as an incentive for Consumers to negotiate lower unit costs with contractors or shift more work to company crews.

Consumers countered that cost increases have resulted from inflation and from increased materials and contractor costs, as well as longer service connections; and that the full 2023 HBAM report actually forecasts an increase in home permits over 2022. 4 Tr 2060. The company noted that, while the December 22 order approved $88.5 million for 2022, Consumers actually spent $128.9 million on new LVD service connections that year. 4 Tr 1871. The company also updated its forecast on rebuttal.

The ALJ recommended that the Attorney General's bridge period adjustment be rejected based on Consumers' updated forecast and the fact that the Attorney General relied on an outdated IHS Markit report. PFD, p. 57. However, the ALJ recommended approval of the Attorney General's proposed 3% reduction to the test year "as a means to incentivize the company to reduce new service installation costs." *Id*.

In exceptions, the Attorney General argues that the bridge period adjustment should also be adopted because the company's forecast for new service lines is excessive, in light of the increase in mortgage rates, the decrease in new housing starts, and high inflation. Attorney General's exceptions, pp. 13-14. She recommends that the Commission apply a 15.9% decline to forecasted new housing starts (based on IHS Markit) for the bridge period, which results in 1,400 fewer housing starts and an $18.2 million disallowance. *Id*., p. 13 (citing 4 Tr 2948).

In exceptions, Consumers states that the Attorney General's position amounts to urging the Commission to reduce rate recovery as an incentive to the company, regardless of whether Consumers has shown that the spending is necessary. Consumers contends that this is "antithetical to cost of service based ratemaking principles, and amounts to an argument that the Company should not incur the costs needed to provide reasonable service to its customers." Consumers' exceptions, pp. 9-10. Consumers contends that it showed that unit cost increases are due to inflation and material/labor cost increases as well as the increasing average length of new service connections, which has increased from 110 feet in 2017 to 137 feet in 2022. *Id*., p. 10 (citing 4 Tr

1869-1870). Consumers states that it still needs to use contractors to meet the new business demand, and argues that its test year projection is supported by the evidence.

In reply to Consumers, the Attorney General argues that Consumers failed to take action to reduce unit costs over recent years and the disallowance is justified. Attorney General's replies to exceptions, pp. 11-14. She notes that Consumers failed to provide a comparison of the cost of installation when performed by company crews and when performed by contractors, and she contends that Consumers should "either negotiate lower unit costs with contractors, shift more work to Company crews, or find other ways to reduce costs." *Id*., p. 13.

In reply to the Attorney General, Consumers argues that the first five months of 2023 showed that actual new service connections were on pace to reach 9,790 in 2023, which is an increase over 2022, and more than the 9,479 used by the Attorney General for the entire bridge period. Consumers' replies to exceptions, p. 17.

The Commission adopts the findings and recommendations of the ALJ. Consumers seeks $108.67 million for the test year for this cost category. The Attorney General's proposed disallowance of $3.28 million represents 10% of the amount that was paid to contractors in 2022. 4 Tr 2950. The Attorney General showed that average costs had increased 51% between 2019 and 2022, when the company began to use more outside contractors. The Commission agrees with the Attorney General that this trend is not favorable and notes that, in response to discovery, Consumers "could not provide a comparison of the cost of installation of service lines by contractors versus Company crews." 4 Tr 2949. The Commission finds that this modest disallowance is appropriate where unit costs appear to be escalating, whether as a result of lengthier lines or increasing material and labor costs, but the company was unable to provide a clear comparison of the cost differentials or a plan as to how to increase the use of company crews or take other measures so as to produce a cost savings.

Metro New Business

This cost category addresses new construction in Consumers' underground Metro service territories. Consumers projected capital spending of $2.8 million in the bridge period and $2.4 million in the test year. 4 Tr 1874-1875.

The Attorney General recommended disallowances of $600,000 for the bridge period and $1.0 million for the test year based on the fact that four of the listed projects are still in the scoping phase of development. 4 Tr 4951; Exhibit AG-1.6. Consumers countered that long lead times may be required.

The ALJ recommended that the Commission adopt the proposed disallowances "because the projects at issue are still in very early development." PFD, p. 58.

In exceptions, Consumers argues that these four projects were in the scoping phase at the time of the discovery response, but that does not mean that they will not be constructed in the test year. Consumers' exceptions, pp. 10-11 (citing 4 Tr 2062). Consumers cites the long lead time for obtaining equipment.

In reply, the Attorney General notes that Consumers admits that the identified projects are still in the scoping phase of development, and argues that the company provided no evidence that the planned bridge period activities will be completed, to allow for further work. Attorney General's replies to exceptions, p. 15.

The Commission agrees that these projects in the scoping phase of development are premature for rate base treatment and adopts the findings and recommendations of the ALJ.

ii. Low Voltage Distribution Reliability

This cost category includes many subprograms addressing reliability on the LVD system. The Attorney General proposed reductions to the subprograms discussed below.

Metro Reliability

This cost category addresses the installation or upgrade of LVD electric assets in Consumers' Metro service territories. Consumers projected $4.67 million in capital expenditures for the bridge period and $4.0 million in the test year. 4 Tr 1955; Exhibit A-122.

The Attorney General calculated that Consumers' projected average per-unit costs are $424,273 for the bridge period and $571,429 for the test year. 4 Tr 2951-2953. The Attorney General calculated an average per-unit cost for the three-year period of 2020-2022 of $209,028, and argued that the projected costs are excessive. Based on using this three-year average adjusted for inflation, the Attorney General proposed disallowances of $2.3 million for the bridge period and $2.4 million for the test year. *Id*. Consumers countered that it is not reasonable to apply the unit cost approach to this cost category because there are a relatively small number of units each year, and each project has highly variable costs.

The ALJ recommended that the proposed disallowance be rejected, finding that:

> looking at individual costs and units shown in lines 50-52 of [Exhibit A-139] (i.e., costs for obsolete or needed civil and electric assets and dead fronting equipment) shows a substantial variation in unit costs year over year. For example, in 2021, Consumers invested $1,769,322 for one project in the Obsolete or Needed Civil Asset spend category, whereas the company invested a total of $712,306 for nine projects in the same category in 2022, with a unit cost of $79,145, an amount that is less than 1/20th of the unit cost for Obsolete or Needed Civil Assets in 2021. As such, the PFD finds that the Metro Reliability subprogram projection should be based on actual project costs and not on average unit costs updated for inflation.

PFD, p. 61.

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

Low Voltage Distribution Lines Rehabilitation

This cost category addresses the repair or replacement of LVD lines and equipment at risk of imminent failure. 4 Tr 1974-1981. Consumers projected capital expenditures of $26.2 million in the bridge period and $32.08 million in the test year.

Focusing on the Imminent Rehabilitation subprogram within this cost category, the Attorney General noted that Consumers projected spending of $11.3 million in the bridge period for 833 units and $29.1 million in the test year for 1,363 units. The Attorney General argued that data from the three-year period of 2020-2022 shows a declining number of units rehabilitated each year, with an average of 663 units per year. 4 Tr 2955; Exhibit A-139. On that basis, the Attorney General proposed a disallowance of $1.27 million for the bridge period. With respect to the test year, the Attorney General used Consumers' bridge period per-unit projected cost adjusted for inflation, and proposed a disallowance of $20.09 million for the test year. 4 Tr 2956. Consumers countered that the unit cost approach is not appropriate for this cost category because of the variability in the cost of work for each project.

The ALJ recommended that the Attorney General's proposed disallowances be adopted. PFD, p. 64. She found that:

> this is largely an emergent program and the number of lines to be rehabilitated are identified on an ongoing basis, making projection more difficult. And the number of units completed is significant, ranging from 500 to over 1,000 per year. As such, the use of a unit cost approach, as well as a projection of work units based on a multi-year average is appropriate, especially when the number of units rehabilitated is trending downward.

Id. (footnote omitted). The ALJ also found that Consumers had not adequately explained the almost 60% increase in unit costs between the bridge period and test year.

In exceptions, Consumers argues that this equipment has been assessed to be at risk of near-term failure and this work will reduce outage frequency. Consumers' exceptions, pp. 14-15.

Consumers contends that its projection is more accurate than the three-year average offered by the Attorney General, and notes that the company completed almost double the 663 annual unit number applied by the Attorney General in 2018 and 2019 (citing 4 Tr 2065-2066). The company insists that average unit cost does not provide a good basis for projection because of the wide variance in the work that is required, which ranges from $100 to $250,000 per project. Consumers contends that:

> [t]he disallowance that the PFD recommends would remove about 70% of the Company's proposed investment in the LVD Rehabilitation sub-program, Imminent Rehabilitation investment category, in the test year. 4 TR 2066. And the PFD's proposed expenditure of $11.781 million in the test year is nearly one-half of the minimum annual investment in the LVD Lines Rehabilitation sub-program over the last five years, which has ranged from $22.331 million in 2020 to $35.548 million in 2021. 4 TR 1982, 2066-2067. It is unreasonable to expect that the Company should spend less than half the amount in LVD Lines Rehabilitation in the test year than in any of the previous five years.

Consumers' exceptions, pp. 15-16. The company asserts that this would result in an historically low level of investment.

In reply, the Attorney General argues that Consumers provided evidence showing that no actual failure has occurred, that these projects are identified outside of normal inspection cycles, and that there is no immediate need for repair. Attorney General's replies to exceptions, p. 22 (citing 4 Tr 1976). She notes that the annual average number of projects in 2020-2022 was 633, and yet the company forecasts 833 for the bridge period (14 months) and 1,363 for the test year. The Attorney General also notes the increase in per-project costs (the unit) from $13,539 for the bridge period to $21,344 for the test year. She argues that the unit cost used for her proposed adjustments, which is based on the bridge period unit cost adjusted for inflation, is more reasonable. *See*, 4 Tr 2955-2956.

The Commission agrees with the ALJ that neither the per-unit cost escalation nor the greatly increased number of projected projects have been adequately explained. *See*, 4 Tr 1974-1981, 2065-2067. The Commission adopts the findings and recommendations of the ALJ.

Metro Rehabilitation

This cost category addresses repair and replacement of LVD electric assets in Consumers' Metro service areas at risk of imminent failure, and allows Consumers to maintain a redundant system in certain downtown areas of cities. 4 Tr 1985-1989. Consumers projects capital spending of $6 million each, in both the bridge period and the test year.

The Attorney General recommended a disallowance of $1.1 million from the bridge period and $1.0 million from the test year amounts based on applying a three-year 2020-2022 average spend adjusted for inflation. 4 Tr 2957. Consumers countered that this program focuses on the components of the Metro systems that are most vulnerable to failure.

The ALJ recommended that the proposed disallowance be rejected, noting that Consumers' projection, "while somewhat higher than the historical average for this category of costs, is tied to specific Metro projects that are necessary for improved reliability and public safety." PFD p. 66.

In exceptions, the Attorney General argues that Consumers' historical spending in this category does not align with its projections. She notes that the company forecasts eight projects in the bridge period and five in the test year with a $6 million spend for each, but Consumers spent only $4.7 million in 2022 on 22 projects. Attorney General's exceptions, p. 15 (citing 4 Tr 2957). She contends that the Commission should adopt the disallowances that arise from the use of the three year average (which incorporates high and low project costs from these previous years). She further asserts that the company presented no evidence to support the argument that a disallowance could impact reliability.

In reply, Consumers argues that spending has increased because the company is addressing additional rehabilitation projects in the bridge and test year period. Consumers' replies to exceptions, pp. 18-19. Consumers states that these assets are at high risk of failure and the projects are identified and planned and provided the basis for the company's projections, which, the company argues, is superior to the simple average proposed by the Attorney General.

The Commission finds that Consumers provided adequate evidence in support of these projects and adopts the findings and recommendations of the ALJ.

iii. Low Voltage Distribution Lines Capacity

This cost category addresses potential overloads that could occur on the LVD system due to increased demand, load growth, or load shifting, including growth that may be expected from increased EV charging. 4 Tr 2010-2018. Consumers projected capital expenditures of $12.57 million in the bridge period and $14.9 million in the test year. *Id*.

The Attorney General supported two disallowances. First, she addressed the Agnew Substation Lake Circuit (Lake Circuit) project, and noted that, to reach the anticipated overload on the circuit, this project would have to enroll 168 EV customers by 2027, which is a 14-fold increase over the number enrolled in the three-year period of 2022-2024. 4 Tr 2959. On that basis, she recommended a $438,000 disallowance for the test year.

The ALJ agreed with the Attorney General and recommended adoption of the disallowance because "the company's own projection of EV growth demonstrates that the Agnew Substation Lake Circuit upgrade is premature and need not be undertaken in the test year." PFD, p. 68.

In exceptions, Consumers argues that the Lake Circuit will be overloaded when 12% of customers add EV charging by 2027, and the disallowance would "send a signal that EVs are not welcome in Consumers Energy's service territory." Consumers' exceptions, p. 26.

In reply, the Attorney General argues that the anticipated circuit overload in 2027 is unlikely to occur because it would require 168 EV customers to enroll by that time, which is a 14-fold increase over the historic rate of enrollment. Attorney General's replies to exceptions, p. 28. She contends that this is not a convincing showing that the overload will occur.

The Commission agrees with the Attorney General and the ALJ that the anticipated overload appears to be unlikely, at least in the proposed timeframe, and, based on the absence of supportive evidence demonstrating a forecasted overload on this specific circuit, adopts the findings and recommendations of the ALJ on the Lake Circuit project.

Second, the Attorney General addressed the Overload Equipment Upgrades cost category within this program. She noted that Consumers projects capital spending of $5.7 million to complete 21 overloaded equipment upgrade projects in the bridge period, and $11.2 million to complete 157 projects in the test year, but the three-year period of 2020-2022 reflects an average of 44 units annually at an average per-unit cost of $136,249. 4 Tr 2960. The Attorney General argued that the bridge period projection of $270,952 per-unit is excessive, and, applying the historical average adjusted for inflation, she recommended a $2.72 million disallowance for the bridge period. For the test year, the Attorney General noted the significant increase in the number of units and argued that, in discovery, Consumers provided little in the way of explanation for the increase. The Attorney General again applied the annual historical average of 44 units per year to the inflation adjusted per-unit average cost over that time, and recommended a disallowance of $4.86 million for the test year. 4 Tr 2961. Consumers countered that the unit cost approach is not appropriate for this cost category.

The ALJ found Consumers' bridge period projection to be reasonable, but recommended adoption of the proposed test year disallowance of $4.86 million. She found the number of test year units to be "significantly overstated and unsupported" in light of the historical average of 44 and the historical high of 59 units per year. PFD, p. 71.

In exceptions, Consumers argues that it has not over-planned for the test year and that delaying the replacement of this overloaded equipment may lead to unplanned outages. Consumers' exceptions, p. 27. Consumers contends that these projects address components of the LVD system "that have already experienced a load greater than their capacity." *Id*. (citing 4 Tr 2069).

In exceptions, the Attorney General argues that the bridge period is also overstated because the per-unit projected cost is nearly double the average unit cost and Consumers has not provided evidence supporting this escalation. Attorney General's exceptions, p. 17. She recommends removing $2.72 million from bridge period estimated expenditures.

In reply, Consumers argues that these identified and planned projects were evaluated by the company for costs and benefits and were used to form its projections, and the average unit cost basis applied by the Attorney General is an inferior method due to the wide variance in the work required which can range from $1,000 to $950,000. Consumers' replies to exceptions, p. 20 (citing 4 Tr 2020). Consumers notes that the Attorney General did not challenge the need for this work.

In reply to Consumers, the Attorney General argues that Consumers' annual average number of units completed during 2020-2022 is 44, making the completion of 157 units in the test year look unlikely. She contends that the company failed to adequately explain the large proposed increase and failed to address whether it is realistic. Attorney General's replies to exceptions, pp. 30-31.

As with the Lines Rehabilitation category, the Commission finds that Consumers failed to adequately support the greatly increased number of units proposed for the test year. The Commission adopts the findings and recommendations of the ALJ.

iv. Low Voltage Distribution Metering

This cost category addresses the installation of meters and related equipment for connecting new residential and C&I customers and the replacement of metering equipment for existing customers. 4 Tr 2038-2044. Focusing on two subprograms addressed by the Attorney General, Consumers projected capital spending for the LVD Metering New Business subprogram (New Business) of $16.6 million in the bridge period and $17.4 million in the test year; and for the LVD Metering Demand Failures subprogram (Demand Failures), Consumers projected capital spending of $39.5 million in the bridge period and $36.2 million in the test year. Consumers noted that a unit cost approach would not be appropriate for these subprograms due to the wide variance in cost among, for example, meters, metering sockets, and meter transformers. 4 Tr 2045-2046.

The Attorney General recommended disallowances of $5.64 million from the projected bridge period and $6.3 million from the projected test year capital investments for New Business, and $5.6 million and $4.9 million from the company’s projected bridge and test year capital expenditures, respectively, for Demand Failures. 4 Tr 2963-2967. For New Business, the Attorney General calculated an average unit cost of $373 per meter for the years 2019, 2020, and 2022 (omitting 2021 based on Consumers’ testimony that it represented an anomaly), and compared that to the bridge and test period average costs of $586 and $620, respectively. She also noted that meter costs are contractually fixed until 2032. Using the three-year average adjusted for inflation, the Attorney General recommended a disallowance of $5.6 million for the bridge period and $6.3 million for the test year. *Id*. For Demand Failures, the Attorney General used the same unit cost plus inflation approach to arrive at disallowances of $5.6 million in the bridge period and $4.9 million in the test year. *Id*. Consumers again countered that the unit cost approach is not reasonable for this work.

The ALJ found that Consumers failed to explain the significant cost increases in light of the fact that metering costs are fixed until 2032. Noting that the Attorney General excluded the lower costs from 2021, the ALJ recommended that the Commission adopt the Attorney General's proposed disallowances for both New Business and Demand Failures for both the bridge and test year periods. PFD, p. 75. The ALJ also observed that the net present value (NPV) for advanced metering infrastructure (AMI) (discussed below) indicates that more needs to be done to realize the benefits of AMI and control meter costs. *Id*.

In exceptions, Consumers argues that it provided evidence supporting the rise in unit costs. Consumers states that it obtained replacement meters at only $10 per meter in 2021 and 2022, and, if these units are excluded from the calculation, then 2021 had a unit cost of $439 and 2022 had a unit cost of $546. Consumers' exceptions, p. 28 (citing 4 Tr 2044). Consumers notes that the Attorney General failed to remove 2022 from her calculation and asserts that, applying un-skewed unit costs, the bridge period and test year unit costs are lower than the 2022 unit cost. Consumers maintains that there is no significant unit cost increase once the cheaper units purchased in 2021 and 2022 are removed.

Consumers further notes that the price of meters may be fixed until 2032, but metering costs consist of much more than just meters, including metering transformers, meter sockets, and costs associated with the variation in the mix of quantity and types of devices. Consumers notes that meters themselves range from $125 to $3,000 per meter. Consumers asserts that its projections are based on major known projects and historical use over the last three years and are reasonable.

Consumers' exceptions, p. 30 (citing 4 Tr 2045-2046). Finally, Consumers asserts that the AMI business case should "not be used to determine whether the Company should continue to purchase meters" because the company is required to supply meters as needed to connect new customers and to keep existing customers connected. Consumers' exceptions, p. 29.

In reply, the Attorney General argues that, with respect to meters for new customers, the projected bridge period and test year unit costs show a 57% and 66% increase, respectively, "over historical unit costs and 131% and 145% over 2022 actual unit costs in 2022." Attorney General's replies to exceptions, p. 31 (citing 4 Tr 2962-2963). With respect to meters for Demand Failures, the Attorney General notes that the projected bridge period and test year unit costs "represent a 21% and 23%, increase respectively over historical unit costs and 75% and 79% over 2022 actual unit costs in 2022." Attorney General's replies to exceptions, p. 33 (citing 4 Tr 2962-2963). The Attorney General argues that Consumers' chart purporting to show the difference between costs with and without the years 2021 and 2022 is accompanied by no supporting data explaining how the higher costs were determined. She contends that the ALJ correctly concluded that the cost increases were not explained.

The Commission finds that the Attorney General's proposed disallowances for both New Business and Demand Failures should be approved. The Commission notes that the $10/meter represents an actual cost, and even with that cost removed for 2021 (though not for 2022), the proposed increases for the bridge and test year periods over historical costs are significant and do not appear to be explained simply by the fact that there are more than meter purchases comprised in the total cost of this work. The Commission adopts the findings and recommendations of the ALJ.

c. Grid Modernization

This cost category involves investments in grid infrastructure improvements and the incorporation of new technologies in order to increase reliability, facilitate the penetration of distributed energy resources (DERs), and prepare for EV growth. 4 Tr 1562-1565.

i. Automation

This program includes several subprograms focused on the deployment of smart devices and technologies, one of which is the Distribution Supervisory Control and Data Acquisition subprogram (DSCADA) which addresses voltage optimization. Consumers projects capital spending of $7.8 million in the bridge period to install 14 DSCADA communication devices, and $7.13 million in the test year to install six DSCADA devices. 4 Tr 1562-1573.

The Attorney General proposed disallowances of $4.2 million from the bridge period and $2.99 million from the test year, based on a three-year (2020-2022) average cost adjusted for inflation for the number of projected devices. 4 Tr 2977-2978. Consumers countered that the unit cost approach is not appropriate for this category because each project has a different scope and calls for different types of equipment based on the specific needs to be addressed.

The ALJ recommended that the proposed disallowances be rejected, finding that:

> [a]s shown in Figure 3 at 4 Tr 1573, the company's investments in DSCADA to date have demonstrated benefits equal to 2.58 times the cost and, as [Consumers] testified, DSCADA supports other grid modernization efforts that also show benefits that well exceed the costs of the programs. Moreover, a review of Exhibit A-110, shows that while most of the DSCADA project costs are in line with [the Attorney General's] unit cost calculation, three projects (Calvin, Palmyra, and Birch Run) are significantly more expensive, thus increasing the total and per unit costs.

PFD, p. 78.

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

ii. Grid Advanced Technologies

This program contains several subprograms, including the Advanced Distribution Management System Enhancements subprogram (ADMS Enhancements) which addresses the need to provide work crews with real-time circuit maps and offers a distribution management platform. 4 Tr 1678-1680. Consumers stated that within the prior seven months, ADMS Enhancements has saved customers five SAIDI minutes, and the company projected a savings of ten minutes by the end of the initial year. 4 Tr 1678; Exhibit A-211. Consumers projected capital spending of $1.58 million for the test year for ADMS Enhancements.

First, the Attorney General proposed disallowances of $906,000 for the bridge period (an estimate) and $1.58 million for the test year, arguing that the ADMS was implemented in 2022 and the proposed "Enhancements" should have been included at that time. 4 Tr 2981-2982. The company countered that the enhancements allow Consumers to obtain the full benefit of ADMS, that a benefit cost analysis (BCA) was provided when the original ADMS project was approved, that the SAIDI benefit demonstrated in this case is based on actual restoration times, and that it is not requesting any funds for the bridge period. 4 Tr 1718-1719. Consumers noted that it was not able to build, test, and install all of the features of the ADMS product when the product was first launched. 4 Tr 1717.

The ALJ recommended rejection of the proposed disallowances based on the fact that ADMS Enhancements are producing reliability improvements, as demonstrated in Exhibit A-211. PFD, p. 81.

In exceptions, the Attorney General argues that the ADMS was implemented in June 2022 at a cost of $66.4 million and the cost of the enhancements should be denied. She contends that the company apparently installed a partially functional system and did not provide a BCA to justify these additional costs but instead claimed that the original BCA was sufficient. Attorney

General's exceptions, p. 18. The Attorney General argues that Consumers provided no evidence that the ten minute SAIDI reduction has been achieved, and that the company's existing goals are questionable and do not justify the proposed spending.

In reply, Consumers argues that the ADMS Enhancements, which provide field crews with real-time circuit maps and improve the system platform, have already saved customers five SAIDI minutes (at the time of filing rebuttal) and would save ten SAIDI minutes by the end of the year. Consumers' replies to exceptions, p. 21 (citing 4 Tr 1678-1680). Consumers notes that it included no expenditures for this cost category for the bridge period. Consumers notes that the Attorney General did not dispute the ALJ's finding with regard to the bridge period and argues that her findings should thus be adopted. Consumers contends that, although the Attorney General was not satisfied with the company's explanation for why the enhancements could not be initially included, "[u]pgrades are vital to the life cycle of any system and ensure the vendor is able to support it" and the ADMS was launched with room to grow in order to support a higher level of automation. Consumers' replies to exceptions, p. 22 (citing 4 Tr 1719). Consumers contends that Exhibit A-211 shows how the company relied on historical data to calculate the SAIDI reduction and these enhancements are economically justified (and were included and justified in the original BCA). Consumers' replies to exceptions, pp. 23-24.

The Commission agrees with the ALJ that the ADMS Enhancements are producing beneficial reliability results, and is not persuaded that the cost of the enhancements cannot be recovered simply because they were not incurred at the time of the initial implementation of the ADMS. The Commission adopts the findings and recommendations of the ALJ.

Second, addressing the entire cost category of Grid Advanced Technologies, the Attorney General objected to the fact that ten major new systems are projected to be implemented over several years but the total future capital costs were not provided on the record. She noted that a preliminary BCA was provided in Exhibit A-113 which reflects spending of $105 million over two years, but Consumers testified that the final BCA is still under development in Case No. U-20898. The Attorney General argued that the BCA in the instant record is inflated and unsubstantiated and cannot be relied upon to justify the projections for Grid Advanced Technologies. 4 Tr 2983-2985. The Attorney General recommended a disallowance of $6.8 million for the bridge period and $12.1 million for the test year for Grid Capabilities – Advanced Technologies because the company's testimony fails to identify or discuss the specific capital expenditures to be undertaken (adjusted to $5.85 million for the bridge period and $10.54 million for the test year if her proposed ADMS Enhancements disallowance is adopted). *Id*.

The Staff did not propose a disallowance, but testified that the BCA offered in support of this cost category has not been approved and contains a number of flaws, including the lack of a societal cost test. 5 Tr 4033-4034.

Consumers countered that it provided sufficient evidence to fully support these programs, and noted that the Staff did not propose a reduction.

The ALJ recommended that the proposed disallowances "be adopted for now." PFD, p. 83. The ALJ found that Exhibit A-113 does not lay out the future costs and benefits for the various investments, and thus:

> a full evaluation of the reasonableness and prudence of the total capital costs, compared to future benefits, is not possible. Second, Staff's and the Attorney General's additional observations about the limitations of the benefit cost analysis presented in Exhibit A-113 are well taken, but these concerns may be addressed in the future as part of Case No. U-20898. Lastly, it may be the case that cost savings associated with grid modernization will be identified as a result of the Commission's distribution system audit established by the October 5, 2022 order in Case No. U-21305. Consistent with the foregoing discussion, this PFD recommends disallowance of $6,775,000 in the bridge period and $10,539,000 [sic] in the test year for the remaining Advanced Grid Technologies programs.

PFD, p. 84. The Commission notes that the ALJ rejected the proposed ADMS Enhancements disallowance for both the bridge and test year periods; thus, the recommended disallowances are $6.8 million for the bridge period and $12.1 million for the test year.

In exceptions, Consumers describes all of the Advanced Technologies projects (other than ADMS Enhancements) and asserts that they are all necessary. Consumers' exceptions, pp. 18-24. Consumers notes that it acknowledged that the BCA framework continues to be under consideration in Case No. U-20898 but still argues that its BCA shows that the full Grid Modernization benefits outweigh the costs. *Id*., p. 22. The company also argues that BCA results should not be the sole determinant of whether these costs are prudent, but instead the Commission should consider the individual projects that are proposed and the benefits expected from each. Consumers contends that the ALJ's sweeping disallowance will "stifle the Company's modernization efforts and prevent customers from realizing valuable reliability and efficiency benefits" such as reduced costs and outage minutes, and improved safety and resiliency. *Id*. (citing 4 Tr 1626, 1634-1638, 1646, 1652, 1654-1655, and 1660-1662).

In reply, the Attorney General argues that the ALJ did not recommend a sweeping disallowance but rather she analyzed the record. The Attorney General argues that Consumers failed to provide future capital costs for the described projects, and the BCA is still undergoing review. Attorney General's replies to exceptions, p. 25.

The Commission agrees with the ALJ's observations regarding the shortcomings of Exhibit A-113 and the evidence supporting these numerous Advanced Technologies projects with the exception of the Distribution Asset Management (DistAM) project. Consumers seeks capital expenditures of $3.77 million for the bridge period and $3.67 million for the test year for this project. 4 Tr 1629. The DistAM project applies asset management principles to attempt to maximize the usefulness and value of electric distribution assets over their lifecycles, and was approved in Case No. U-20697 and re-approved for funding in the December 22 order, pp. 44-45. The Commission finds that Consumers provided sufficient evidence to support the continuation of this project and approves the requested DistAM funding for rate base treatment. *See*, 4 Tr 1619-1630. In particular, Consumers provided evidence showing the benefits of the DistAM project and how the project will support the objectives of Consumers' EDIIP. 4 Tr 1926-1928. However, the Commission notes that its original approval of the DistAM project in the December 22 order was based on the CAD from 2021 which projected total costs of $12 million through 2024, and that original projection has been reached. Thus, the Commission will require updated data, including total costs, for any future cost recovery requests associated with the DistAM project. Finally, while the Commission agrees with the company that BCA results are not the sole determinant of whether costs are reasonable and prudent, the Commission has considered the evidence presented for each of these individual projects and agrees with the ALJ's recommendation to disallow the remaining requested amounts for the bridge period and test year associated with the rest of the proposed Advanced Technologies projects.

Though no capital expenditures were projected for inclusion in rate base for the DER Gateways or the DER Management Systems (DERMS) subprograms, MEIBC/IEI/United made several recommendations regarding these subprograms which the ALJ addressed. MEIBC/IEI/United observed that Consumers' definition of DERMS is too narrow, and made several suggestions for issues that the company could explore prior to seeking cost recovery for DERMS. 5 Tr 3462-3479. In briefing, MEIBC/IEI/United requested that the Commission direct Consumers to engage interested persons in a process to address the stated concerns with the DERMS technology. MEIBC/IEI/United's initial brief, p. 17.

Additionally in this cost category, the Attorney General recommended that the Commission require Consumers to develop a DER participant fee for presentation in its next rate case. Consumers responded that it is still researching this issue.

The ALJ agreed with Consumers that the development of a DER user fee is premature at this time, but recommended that the Commission direct that the issue of how the fee can be used to achieve equitable cost allocation for DER-facilitating technologies be explored in a workgroup process addressing the DER Gateways and DERMS subprograms. PFD, pp. 87-88. The ALJ also agreed with MEIBC/IEI/United's suggestion and recommended that Consumers "be directed to engage with Staff and other interested parties to address concerns about the deployment of DERMS, before requesting cost recovery for this technology." PFD, p. 87.

In exceptions, Consumers argues that it already engages with outside interests regarding DERMS, and states that it would not object to the inclusion of the issue of equitable cost allocation for DER technologies in a dedicated session on this topic, if there is sufficient interest. Consumers' exceptions, pp. 23-24.

In exceptions, the Attorney General argues that the ALJ's recommendation is insufficient because it is not clear what is meant by equitable cost allocation. She contends that "[u]tility customers who do not participate in DER transactions should under no circumstances bear the cost of the DER transactions. The only equitable allocation is for DER participants to pay a fee for their participation." Attorney General's exceptions, p. 21. She urges the Commission to require the company to develop an allocation/fee proposal for presentation in its next rate case or in any case in which the company seeks recovery of DER-related costs.

In replies, Consumers argues that no hardware or software have been selected, additional learnings are needed, and this proposal for a fee is premature. Consumers' replies to exceptions, p. 25.

The Commission agrees with the ALJ that a requirement for a fee proposal (and thus a decision on the equitable allocation of the cost) in the next electric rate case would be premature, and that Consumers should continue to engage with the Staff and interested persons on these DER-related topics. The Commission notes that in the December 1 order, p. 322, the Commission directed the Staff to convene a workgroup to consider certain broader DER-related issues including: "(1) whether tying of retail and wholesale DR programs by the retail electric provider is appropriate; (2) whether a FIT [feed in tariff] or other tariff mechanism is needed or advantageous;" and any related issues that the Staff finds to be appropriate. While the Commission finds the topic of a DER user fee to be premature for rate case consideration at this time, this topic may be appropriate for future consideration by this workgroup.[4]

d. Undergrounding Pilot

This proposed pilot program will replace certain sections of overhead LVD lines with underground LVD lines. The pilot is intended to allow Consumers to study the actual improvements to reliability that are delivered by undergrounding, and how undergrounding compares to other approaches to improving reliability, including an analysis of cost. 4 Tr 373-377. Consumers projected capital expenditures of $400,000 per mile to perform 10.3 miles of undergrounding, for a total of $4.1 million in capital spending in the test year. *Id.* Consumers indicated that it may perform an additional 11.3 miles of undergrounding, and sought deferred

[4] *See,* https://www.michigan.gov/mpsc/commission/workgroups/demand-response-aggregation (accessed February 15, 2024).

accounting for additional amounts. Consumers explained its site selection process at 4 Tr 1999-2000.

The Staff supported the pilot but with a 10% reduction ($413,000) to expenditures, and does not support any additional undergrounding at this time. 5 Tr 3999. The Staff noted that Consumers' historical unit cost is based on the cost of overhead removal in rural areas, making the pilot a new activity for the company. As such, the Staff recommended a 10% reduction to protect customers from a potentially inflated unit cost assumption. *Id*. Consumers countered that its cost estimate is conservative because work in rural areas is less complex.

The ALJ recommended adoption of the Staff's proposed disallowance and limit on the miles of undergrounding, finding that "one of the goals of the pilot is to confirm the cost of undergrounding; thus, Staff's modest reduction protects customers in the event that per-mile undergrounding costs are less than Consumers projected." PFD, p. 90. She noted that reasonable and prudent costs may always be sought in a future rate case.

In exceptions, Consumers argues that the Staff did not offer evidence supporting its proposals; and that the Staff's rationale is simplistic, namely, that this is a new activity. The company reiterates that its projections are already conservative because they are based on rural service areas. Consumers' exceptions, p. 32. Consumers contends that the additional 11.3 miles would be consistent with the Commission's expressed intentions in Case No. U-20147.

The Commission finds the Staff's proposals to be reasonable and prudent and adopts the findings and recommendations of the ALJ. Learnings resulting from the first 10.3 miles of undergrounding should contribute to the efficiency of future miles. Further, as noted by the ALJ, the company can seek recovery of reasonable and prudent costs in a future rate case.

2. Streetlighting Capital Expenditures

Consumers owns and maintains approximately 173,000 streetlights that are either light emitting diode (LED) or high intensity discharge (HID) luminaires. HID luminaires include mercury vapor (MV), high pressure sodium (HPS), or metal halide (MH) technologies. 4 Tr 2262-2263. Consumers explained that MV technology is obsolete, and the use of MH and HPS technology is being phased out. In addition, HIDs are much less efficient and have a shorter lifespan than LEDs. For all of these reasons, the company began to reactively convert HIDs to LEDs in 2018, and about 53,000 HID fixtures remain. 4 Tr 2281-2283. This work is still done reactively, though Consumers now also proactively converts HID fixtures that are in close proximity to a failed HID luminaire. In the instant case, the company recommends some planned conversions of HIDs to LEDs. 4 Tr 2289-2291. Consumers explained the process that it uses to ensure the replacement LED provides equivalent lighting to the removed HID luminaire. 4 Tr 2276-2280.

Consumers projects capital expenditures of $13.7 million to address 15,396 streetlight failures during the bridge period and $12.0 million to address 13,197 streetlight failures during the test year, based on four-year historical average expenditures (2019-2022) adjusted for inflation. 4 Tr 2283-2284, 2303. Consumers also projects amounts associated with proactive conversions and new business, and thus seeks a total of $19.12 million for the bridge period and $16.7 million for the test year.

The Staff noted that in Case No. U-21224 Consumers projected spending of $19.5 million for 2022 and $19.9 million for 2023, but it had actual expenditures of $14.9 million in 2022 and now projects spending of $16.3 million in 2023. 5 Tr 3957-3958. On that basis the Staff recommended a 20% disallowance for the two-month bridge period ending February 29, 2024 ($556,400), and a 20% disallowance ($3.34 million) for the test year. 5 Tr 3957. Consumers did not dispute the underspending, but countered that its projection, which is based on a four-year average, is more reliable than the Staff's projection, which is based only on recent underspending. 4 Tr 2303-2305. The company also notes that its full projection was not approved in the January 19 order.

The ALJ concluded that Consumers' streetlighting projections are excessive. The ALJ recommended "reducing the amount for streetlighting capital expenditures by 20% based on the company's history of under spending, and that recommendation extends to new streetlighting installations for the same reason. Indeed, in Case No. U-21224, the Company projected spending $3.762 million on new streetlight installations, but spent $2.799 million." PFD, p. 95. Thus, the ALJ recommended that the Commission adopt a 20% reduction to the bridge and test year period projections.

In exceptions, Consumers argues that its projection method is reasonable. Consumers states that it uses four-year historical average expenditures as the basis for projecting streetlight failures and five-year historical average expenditures as the basis for projecting new business capital expenditures, adjusted for inflation. Consumers' exceptions, p. 24 (citing 4 Tr 2303). Consumers contends that it is misleading for the ALJ to say that it has a "history" of underspending, and that:

> Exhibit A-12 (DAS-1), Schedule B-5.10, page 1 shows that the Company's actual cost for Streetlight New Business has exceeded the Company's forecasted costs in three of the last five years and its actual costs for Streetlight Demand Failures has exceeded the Company's forecasted costs in two of the last four years. That is obviously consistent with the fact that the forecast was an average of those prior years.

Consumers' exceptions, pp. 24-25. Consumers argues that the Staff only considered a single year, and maintains that its forecasting method is more accurate because it considers multiple years. Consumers also contends that it usually sees a surge in orders late in the year (which would be missed by the Staff for 2023), and the ALJ's decision will lead to long-term underfunding for this work.

In replies to exceptions, MI-MAUI indicates its support of the ALJ's recommendations. MI-MAUI's replies to exceptions, p. 3.

Consumers does not dispute the historical actual amounts spent as presented by the Staff, and the Commission finds the Staff's evidence on this issue to be persuasive. The Commission agrees with the ALJ and adopts her recommendation of a 20% reduction to the bridge period and test year funding requests for streetlighting capital expenditures. The Commission also finds Consumers' claim that this result will lead to long-term underfunding of this work without merit. As noted above, Consumers can seek to recover reasonable and prudent capital costs in a future rate case. Moreover, it is Consumers' own underspending on this line item that casts doubt on its willingness and ability to spend the funds provided for in rates for this purpose.

Turning to the issue of streetlighting installation and removal, Consumers noted that LED luminaires are used for new installations, which are performed at the request of municipalities. Based on the five-year (2018-2022) historical average adjusted for inflation, Consumers projects capital spending of $4.5 million on 330 new units during the bridge period and $3.94 million on 283 new units during the test year. 4 Tr 2281. MI-MAUI recommended that the Commission disallow all projected capital expenditures for new business of $3.94 million for the test year and require customers to pay the full cost for new installations. MI-MAUI also expressed concerns about streetlight reliability and about Consumers' coordination with municipalities. MI-MAUI argued that, for new streetlights, customers are charged a contribution in aid of construction (CIAC) charge of only $100 per light and the remaining cost of the installation enters rate base, which results in older communities subsidizing newer communities. 4 Tr 3144-3148. MI-MAUI argued that this is an unjust result, as older communities often experience population loss and thus have fewer resources. *Id*. MI-MAUI recommended that the Commission require Consumers to charge new customers the full cost of the installation (disallowing the $3.94 million for new business for the test year) and mandate that the customer receive the return of and on the investment, which MI-MAUI calculated to be 9.4 years of tariff payments. 5 Tr 3148-3151. MI-MAUI recommended that this practice also be adopted for streetlight removal.

The Staff noted that new streetlighting customers pay the same base rates as existing streetlighting customers after their CIAC payment of $100, and those base rates include the costs related to the addition of new streetlights to the system. 5 Tr 3694-3700. Thus, the Staff argued that new streetlighting customers are not subsidized by existing customers. The Staff noted that both existing and new customers will have paid for their streetlights via base rates in 9.4 years. 5 Tr 3697. The Staff also opposed the concept of treating streetlighting removal the same as streetlight installation, because after removal the customer is no longer paying base rates and thus has no opportunity to pay the cost of removal via base rates.

Consumers also opposed MI-MAUI's proposals. Consumers noted that streetlighting contracts require the customer to pay the costs of removal, and the Commission rejected the same proposal from MI-MAUI regarding removal in Case No. U-20963. *See*, December 22 order, p. 362. Consumers also noted that the Commission approved the CIAC payment and rate base treatment for streetlight installation in 1991 in Case No. U-9346. 4 Tr 2295-2297.

The ALJ recommended that the Commission retain the current system for payment of streetlight installation and removal, finding that:

> no evidence was presented to substantiate [MI-]MAUI's claims that ratepayers who live in communities with declining populations are paying for significantly more streetlights, without benefit, than ratepayers in other communities. Moreover, because prior to 1991 there was no customer contribution for the cost of new streetlight installations and it is therefore reasonable to conclude that the communities with declining populations today, received the benefit of new streetlight installation without any cost in the past, this PFD accepts Consumers' conclusion that the $100-per-light charge is not inefficient or unfair. Likewise, this

> PFD rejects [MI-]MAUI's recommendation to require the company to discontinue charging the full cost of streetlight removal for reasons set forth in [the Staff's] testimony and Staff's brief.

PFD, p. 100 (footnote omitted).

In exceptions, MI-MAUI argues that the CIAC fee for installation is too low and the fee for removal is too high. MI-MAUI contends that the Commission should disallow $3.94 million in new business streetlighting spending because these costs should be covered by the community requesting the streetlight. MI-MAUI's exceptions, p. 2. MI-MAUI asserts that it presented sufficient evidence demonstrating that older communities are subsidizing newer communities via the current CIAC fee by covering all costs beyond $100. MI-MAUI argues that it showed that while the overall population of Michigan has increased by only 0.25% between 1990 and 2022, the population of the City of Flint decreased by 43.3%, thus demonstrating that older communities are subsidizing newer ones. *Id*., p. 3. MI-MAUI explains that the company earns more revenue if more poles are installed, and states that both Consumers and the Staff "admitted they had never actually calculated whether creating a more far-flung system to serve essentially the same population results in cost savings to older communities." *Id*. MI-MAUI adds that the full cost of streetlight removal should not be charged directly to the customer.

In reply, Consumers argues that the present policy was established in 1991 and is efficient and fair, noting that "the old customers' rates include a portion of the investments for the new customers' streetlights, but the new customers' rates also include the remaining portion of the investments for the old customers' streetlights." Consumers' replies to exceptions, p. 26. Consumers contends that the Staff correctly explained that new customers do not end up paying less than existing customers because costs are paid collectively by rate class and all customers benefit from the addition of new customers because new customers contribute to the revenue requirement responsibility. *Id*., pp. 26-28 (citing 5 Tr 3695-3698). Consumers notes that the Commission has considered and rejected MI-MAUI's streetlight removal proposal in the December 22 order, p. 362. Consumers again notes that the Staff explained the installation and removal should not be treated the same, because removal customers are leaving the system and thus will no longer be able to contribute to the removal cost through base rates.

As Consumers, the Staff, and the ALJ highlight, the present policy for funding the installation and removal of streetlights was approved in 1991 and the Commission is not persuaded that this system requires reform. The Staff provided convincing evidence that no subsidization is occurring, that additions to streetlighting are good for all members of the affected rate class, and that the present removal policy makes sense in light of the fact that the customer seeking removal will no longer be paying streetlighting related costs with respect to the removed streetlight. 5 Tr 3694-3700. Thus, the Commission adopts the findings and recommendations of the ALJ on this issue of streetlight installation and removal. However, in light of its 1991 adoption, the Commission directs Consumers in its next general electric rate case to provide a demonstration that the $100 CIAC fee remains the appropriate contribution in light of cost of service principles and the function of the fee.

Finally, in exceptions, MI-MAUI argues that the ALJ failed to address its request that the Commission require Consumers to involve local units of government in the distribution planning process and require the company to provide evidence of its efforts to do so as a condition for recovering distribution system costs. MI-MAUI's exceptions, p. 1. MI-MAUI notes that the Commission has actually already addressed this issue in the December 1 order, pp. 361, 375, where DTE Electric was required to improve coordination with local governments; and in the December 21, 2023 order in Case No. U-21388, pp. 7-8, where the Commission has initiated technical conferences covering similar topics regarding communication and coordination and has required Consumers and DTE Electric to meet with local governments.

In reply, Consumers contends that it already performs the necessary coordination and that MI-MAUI's request is impractical. Consumers' replies to exceptions, pp. 3-5. Consumers asserts that it already provides opportunities for feedback through technical conferences and community engagement meetings which take place prior to certain Metro projects, and notes that all new streetlight requests come from municipalities. Consumers also notes that the final order in Case No. U-21297 (the December 1 order) does not require the utility to consult with local governments in order to engage in distribution planning and recovery of distribution investments. Consumers points out that MI-MAUI's witness testified that "[i]n general, governments find Consumers does coordinate use of the right-of-way well and keeps governments apprised of planned work in their area." *Id*., p. 5 (quoting 4 Tr 3163). Consumers also contends that the Commission does not have clear statutory authority to impose such a requirement, and MI-MAUI presented no evidence showing how this would benefit ratepayers.

The Commission rejects MI-MAUI's proposal. As MI-MAUI notes, in the December 21, 2023 order in Case No. U-21388, pp. 8-9, the Commission stated the following:

> The Commission believes a first step in addressing communication and coordination requires clear frameworks and expectations for collaboration and coordination between utilities and local governments and to strengthen communication protocols between utilities and governments. As such, the Commission directs DTE Electric and Consumers to convene one or more meetings with a representative sample of local government officials and emergency response teams within their respective service territories not later than March 31, 2024, for the purpose of improving these communication protocols between utilities and local governments during outages and extreme weather events, and to report back to the Staff on the learnings and next steps stemming from these meetings not later than April 30, 2024. . . . Further, as part of the meetings with local leaders and emergency response teams, DTE Electric and Consumers shall provide an overview of their outage management systems and processes and provide an opportunity for other participants to pose questions on these systems and processes.

> In addition, the questions posed during the technical conference sessions related to data and mapping focused on three primary issues: (1) how can utilities better utilize available data to improve resilience performance, (2) how can the Commission do more with data to add transparency and accountability, and (3) how can utilities improve the appropriate sharing of data with third parties in order to enable additional resilience solutions. Much of the work in response to these questions is being undertaken in other dockets, including the ongoing review of utility reporting in Case No. U-21122 and an order in Case No. U-20959 relating to a range of customer data sharing issues as part of the MI Power Grid Customer Engagement workstream.

The Commission also indicated that a publicly available website would be ready in the first quarter of 2024, and invited further comment on these issues in July 2024. *Id*. The Commission finds that MI-MAUI's stated concerns may be addressed in the referenced dockets and encourages MI-MAUI to participate in that effort.

3. Generation Capital Expenditures

a. Overview

Consumers provided testimony in support of its overall generation capital expenditures, with a summary of company-owned generating plants and its generation asset strategy and projections. 4 Tr 820-845.

b. Fossil Generation and Ludington Pumped Storage

This cost category addresses fossil and hydraulic generation spending and spending related to the Ludington Pumped Storage Plant (Ludington). The Staff proposed a $4.7 million disallowance for the test year associated with 11 projects. 5 Tr 3869-3871. The Staff relied in part on the company's Enterprise Project Management Organization Cost Estimating Manual (Cost Estimating Manual), which describes Consumers' internal cost class estimate standards and classifies projects based upon the certainty of the estimated costs. The Staff found that the further into the future costs are estimated, the greater the uncertainty of the estimation. 5 Tr 3869-3870.

The Staff recommended adjustments to projects with a cost in excess of $1 million and which have a low level of cost certainty. The Staff used the lower limit of Consumers' expected accuracy range for each class estimate level, and recommended a disallowance of $4.7 million in capital expenditures from the projects listed in Exhibit A-12, Schedule B-5, for the test year. 5 Tr 3871. Consumers countered that there is almost zero probability that 100% of its projects will have an actual cost that is at the low end of the accuracy range. 4 Tr 950.

The ALJ recommended adoption of the Staff's proposed $4.7 million disallowance. PFD, pp. 104-105. The ALJ found that this would protect ratepayers "while at the same time allowing the company to recover actual costs expended for the completion of a project." *Id.*, p. 105.

In exceptions, Consumers states that:

> [d]epending on the level of development of the project on a scale from zero (least developed) to five (most developed), the Company's Cost Estimating Manual identifies an "expected accuracy range" for each cost estimate. See 5 TR 34 3870, Table 1. For every level of development on the scale except level 5, the accuracy range is expressed as some percent below the estimate to some percent above the estimate, with the range narrowing as the project develops based on an increasing level of the engineering completed. 5 TR 3870, Table 1. In reviewing the Company's cost estimates in this case, Staff assumed – without any engineering justification – that all the known projects over $1 million in the test year will result in actual costs below the Company's estimate and consistent with the lowest end of the accuracy range. 4 TR 949; 5 TR 3870-3871.

Consumers' exceptions, pp. 33-34. Consumers contends that the Staff's assumption is unrealistic and that actual project costs settle around the projected costs. Consumers asserts that there is a low-to-zero probability that every project would end up at the low end of the accuracy range. Consumers argues that the Cost Estimating Manual relies on actual statistical experience, making the Staff's assumption improbable and inconsistent with the concept of a projected test year. Consumers further asserts that the Staff's disallowance means that the company will not "recover any return for its reasonable and prudently incurred investments during the first year that investment is in service for customers." *Id*., p. 36. Consumers describes this as poor ratemaking policy.

In reply, the Staff argues that the proposed adjustment is not based simply on the bottom of the accuracy range, but is supported in other ways. The Staff notes that it adjusted only 11 (out of 17) of the projects with costs over $1 million in the test year (and nothing below that amount), and argues that the low end of the accuracy range is a reasonable basis for quantifying uncertainty for these costs which may be recovered in the future in any case. Staff's replies to exceptions, p. 2. The Staff argues that its proposed adjustment is a fair way to address the inherent uncertainty of the projects.

The Commission agrees with the Staff's analysis and adopts the findings and recommendations of the ALJ. As the Staff points out, the Staff did not assign the lowest level of development of the accuracy range to every project in this category but rather only 11 of the projects that exceed $1 million. Some proportion of the total projects is likely to land at the low end of the range, and the Commission finds the Staff's proposal to be reasonable and prudent.

Next, the ALJ addressed the Attorney General's recommendation of a disallowance of $1.824 million in bridge period and $3.619 million in test year capital spending for Ludington. *See*, Exhibit AG-1.16. Consumers countered that the Attorney General had confused Ludington projects with river hydro projects. Noting that the Attorney General failed to address this rebuttal evidence in her brief, the ALJ found that the proposed disallowance should be rejected. PFD, p. 105.

No exceptions were filed on this issue related to capital spending for Ludington and the Commission adopts the findings and recommendations of the ALJ.

c. ABATE's Generation Capital Expenditure Adjustments

ABATE recommended several generation capital disallowances which are discussed below.

i. Covert Plant Non-Long-Term Service Agreement Capital Expenditures

Normal maintenance at Consumers' Covert Plant is covered by its long-term service agreement (LTSA). However, Consumers projected capital spending associated with repair and replacement of various systems at the plant (not covered by the LTSA) of $3.94 million in the bridge period and $5.5 million in the test year. 4 Tr 879-880.

ABATE argued that Consumers failed to provide sufficient evidence showing how the expenditures were determined, making the projections speculative. ABATE recommended disallowance of the full amount for this cost category. 4 Tr 2821-2822. Consumers countered that it presented these non-LTSA capital costs in its 2021 integrated resource plan (IRP) in Case No. U-21090. 4 Tr 953.

Noting that the company may recover reasonable and prudent costs in a future rate case, the ALJ recommended that the Commission disallow the full amount sought for these Covert non-LTSA costs "because the company's request for cost recovery is speculative and not adequately supported on this record." PFD, p. 107.

In exceptions, Consumers argues that this maintenance is not speculative and the need for it was addressed in the testimony at 4 Tr 879 and 953. Because it is non-discretionary, Consumers asserts that failure to fund this work "will require the Company to move money from planned, but discretionary, work that the Commission has otherwise recognized as needed and appropriate" and that the need for this work was presented in the company's IRP, thus the Commission "understood the Company would incur these costs upon acquiring the plant and still considered the purchase of the plant reasonable." Consumers' exceptions, pp. 37-38.

In reply, ABATE argues that these costs are not related to any identified work and the company failed to adequately support them or explain how they were determined. ABATE notes that Consumers failed to provide any historical cost data for items the company claimed to be typically not covered by the LTSA. ABATE's replies to exceptions, p. 1 (citing 4 Tr 2821-2822, 953). ABATE contends that this is effectively contingency cost recovery.

The Commission agrees with ABATE and the ALJ that Consumers' evidentiary presentation on this issue was inadequate. The simple fact that a potential expenditure was included in an exhibit in a previous IRP proceeding is not sufficient to demonstrate the reasonableness and prudence of that expenditure in a rate case, and the support provided on the instant record is insufficient. Consumers presented no historical data in support of the request. The Commission recognizes that the asset has not been under Consumers' ownership for long, but finds it probable that the company had access to data that could have been used to support this funding request. The Commission adopts the findings and recommendations of the ALJ.

ii. Karn Unit 3 Cooling Tower Internal Structure Replacement

This cost category addresses a 14-month project to repair or replace various internal structural elements of the Karn Unit 3 cooling tower (which is slated for retirement in 2031). Consumers projects capital spending of $3.97 million in the bridge period and $5.0 million in the test year for this project. 4 Tr 881-884. On rebuttal, Consumers agreed to the Staff's proposed reduction of $697,000 for the bridge period. Exhibit A-189, line 9.

ABATE argued that the full amount should be disallowed. ABATE noted that the project's concept approval document (CAD) was rejected in 2021 and the numbers for the project were thereafter revised, but the project is at least two years behind schedule and there is no reasonable certainty that the project will occur in the bridge or test year periods. 4 Tr 2822-2823. Consumers countered that the delay was due to the unit's changed retirement date (from 2023 to 2031) as a result of the settlement agreement in Case No. U-21090 (Consumers' IRP case), and that it has already begun to spend money on this project. The company also noted that it has already accepted the Staff's adjustment to the bridge period. 4 Tr 955; Exhibit S-12.3, p. 1.

The ALJ recommended disallowance of the full amount "because the company's proposed expenditures are speculative and not adequately supported on this record." PFD, pp. 109-110.

In exceptions, Consumers argues that ABATE's only claim is that the company may not proceed with the project because the project has already been subject to delays. Consumers' exceptions, pp. 38-39. Consumers explains that the previous delays related to the fact that Karn Units 3 and 4 were being considered for retirement in the company's IRP case, and that issue was not resolved until the IRP case settled and it was determined that Karn Unit 3 would remain open until 2031. Consumers contends that it spent more than $1 million in 2023 and is projected to spend the requested amounts with no further delays citing 4 Tr 954-955. Consumers also asserts that any further delay would be risky because structural beams have collapsed under the weight of the water in the cooling tower. Consumers' exceptions, p. 40 (citing Exhibit AB-9, p. 28). The company states that no further engineering is needed and the project is progressing, and a total disallowance will jeopardize the timeline.

In reply, ABATE argues that this cost category lacks supporting documentation. ABATE contends that there were apparently no expenditures in 2022, and the claim of later expenditures of over $1 million in 2023 were unsupported by evidence. ABATE's replies to exceptions, p. 2. ABATE notes that "[a]ll capex [capital expenditure] amounts beyond May 2023 are projections based on a CAD that was rejected by Consumers' personnel during its internal budget approval process." *Id.*

The Commission agrees with the ALJ that these requests were not adequately supported. Consumers mentioned in testimony that it had more than $1 million in actual expenditures in 2023 but offered nothing on the record to support that assertion. As ABATE demonstrated, the CAD has been rejected and the project is more than two years behind schedule, which Consumers did not dispute. The Commission notes that this is an expensive proposition for a unit that sees very little use and directs the company, in its next rate case, to provide an alternatives analysis including information on the most cost efficient solution to this problem and alternatives to full replacement. Recognizing that Consumers already agreed to the Staff's adjustment for the bridge period, the Commission finds that $3.27 million in the bridge period and $5 million in the test year should be disallowed. The Commission notes that reasonable and prudent expenditures may be recovered in a future rate case.

iii. Karn Tank Farm Storage Tank Heating Line Replacement

This cost category addresses the need to replace piping at the Karn Tank Farm which has deteriorated over the years, resulting in significant leakage. Consumers projected capital spending of $1.25 million, originally in the bridge period, for this project. 4 Tr 882.

ABATE recommended disallowance of the full amount because the project has not yet been bid nor has a contractor been selected, the timing is unclear, and discovery responses showed no actual expenditures in the bridge or test year periods. 4 Tr 2823-2824. Consumers countered that the project was delayed due to the change in the retirement date for Karn Unit 3, and the delay caused the company to move the projected expenditures from the bridge period to the test year. Consumers noted that it already accepted the Staff's proposed disallowance for the bridge period and requested deferral of the $1.25 million to the test year.

The ALJ recommended adoption of the full disallowance because "the company did not adequately support the reasonableness of cost recovery under these circumstances where the company has shifted the scope of the project and the actual cost remains speculative as the company has yet to bid the construction labor." PFD, p. 112.

In exceptions, Consumers again argues that this equipment has been purchased, and the previous delays were caused by the uncertainty surrounding Karn Unit 3's retirement date. Consumers' exceptions, p. 41. Consumers notes that the scope of the project has changed because it now plans to construct a solar farm, but contends that the work is not speculative. Consumers contends that the $1.25 million should just be shifted from the bridge period to the test year.

In reply, ABATE argues that this project was not supported by the evidence, noting that, even on rebuttal, Consumers provided testimony that it had "yet to bid the construction labor to install the equipment and the additional pipe, electrical, etc." ABATE's replies to exceptions, p. 3 (quoting 4 Tr 956).

The Commission finds that this project is in the early stages and is not ready for rate base treatment. The Commission adopts the findings and recommendations of the ALJ.

iv. Sync Wire Replacement

This cost category addresses the need to replace copper communication cables between Karn Units 3 and 4 and the Hampton substation. Consumers projected capital spending of $175,275 in the bridge period and $1.27 million in the test year. 4 Tr 882.

ABATE recommended disallowance of the full amount because the project has not yet been bid nor has a contractor been selected, the timing is unclear, and discovery responses failed to show what the spending would support. 4 Tr 2825. Consumers countered that a contractor will be selected in June 2024 and the project will be complete in November 2024. Consumers noted that it already agreed to the Staff's bridge period disallowance of $196,000, and argued that $1.27 million should be moved to the test year. 4 Tr 957; Consumers' initial brief, p. 100.

The ALJ recommended that the Commission approve $175,275 for the bridge period but disallow the remaining request of $1.27 million for the test year because this projection remains uncertain, and noted that reasonable and prudent costs may be recovered in a future rate case. PFD, p. 114.

In exceptions, ABATE argues that the same uncertainty applies to the bridge period amount, and thus the $175,275 should also be disallowed. ABATE's exceptions, pp. 3-4.

In exceptions, Consumers argues that this project was also affected by the uncertainty regarding the future of Karn Unit 3, and the company's "plans for the project have simply shifted in time for a valid reason, which the Company has explained and which the Commission is aware of by virtue of its role in approving the Company's IRP." Consumers' exceptions, p. 42.

In reply to Consumers, ABATE argues that the company acknowledged that it would not be awarding a purchase order to a contractor until June 2024, and it is unclear what the expenditures are supposed to support. ABATE's replies to exceptions, p. 4.

In reply to ABATE, Consumers argues that this project was delayed due to the uncertainty regarding the retirement date in the IRP proceeding and it would be appropriate to move these costs to the test year with full approval. Consumers notes that Exhibit AB-9, p. 67, shows the company had actual spending through May of 2023 of $114,200. Consumers' replies to exceptions, p. 31.

The Commission finds that the full costs for this project are also not ready for rate base treatment and, on that basis, agrees with ABATE that the bridge period amount should also be disallowed. The Commission approves disallowance of the $175,275 sought for the bridge period and the $1.27 million originally sought for the test year.

v. Heat Recovery Steam Generator Burner Element Isolation Valves Addition

This cost category involves the replacement of burner components that are at the end of their life and the addition of solenoids, associated with the heat recovery steam generator (HRSG) units. Consumers projected capital spending of $2.02 million in the bridge period for this project. 4 Tr 887-893.

ABATE recommended disallowance of the full amount because the project has not yet been bid nor has a contractor been selected, the timing is unclear, and discovery responses failed to show what the spending would support since there is, as yet, no contract bid or contractor. 4 Tr 2825-2826. Consumers countered that it awarded a contract in August 2023 and the project would be complete in October 2023. Thus, Consumers requested approval of the $2.02 million for the bridge period less the Staff's disallowance of $65,000, to which the company agreed. 4 Tr 958-959.

The ALJ found that this project was adequately supported on the record and recommended that the Commission approve the $2.02 million for the bridge period less $65,000. PFD, p. 115.

In exceptions, ABATE argues that "[t]here is no reason to approve a projection here when the actual amount of reasonable cost recovery can be reviewed in the Company's next rate case." ABATE's exceptions, p. 4.

In exceptions, Consumers contends that the PFD is mistaken because the Staff did not propose a $65,000 disallowance but rather a $65,000 increase which was mistakenly referred to by Consumers' witness (Mr. Blumenstock) as a disallowance. Consumers' exceptions, p. 43 (citing

Exhibit S-12.3, p. 1). Consumers argues that the Commission should agree with the ALJ and adopt the $2.02 million *plus* $65,000 as recommended by the Staff.

In reply to Consumers, ABATE argues that the project should be disallowed. ABATE's replies to exceptions, p. 4.

In reply to ABATE, Consumers argues that a contract was awarded on August 16, 2023, the planned outage was scheduled for September 2023, and the project would be complete in October 2023 according to the testimony. Consumers' replies to exceptions, p. 32 (citing 4 Tr 958). The company also states that it has agreed with the Staff's proposed increase of $65,000. Consumers notes that ABATE simply objects to the fact that the amount is a projection, and argues that the company is entitled to use a fully projected test year under MCL 460.6a(1). Consumers contends that being required to show only actual costs leads to harmful regulatory lag, and the company will never be reimbursed for the first year of any costs that must be delayed for recovery until they have been spent.

The Commission agrees with the ALJ that this project was adequately supported on the record and approves the requested funding along with the additional $65,000 recommended by the Staff in Exhibit S-12.3, p. 1, line 11.

vi. Heat Recovery Steam Generator Casing Replacement

This cost category involves the replacement of HRSG casing at the Zeeland plant necessitated by corrosion. Consumers projected capital spending of $2.8 million for this project, but was not clear on the exact time period. 4 Tr 885-887.

ABATE recommended disallowance of the full amount because the project has not yet been bid nor has a contractor been selected, the timing is unclear, and discovery responses failed to show what the spending in 2023 would support since there is, as yet, no contract bid or contractor.

Alternatively, ABATE recommended a partial disallowance of $1.493 million because Consumers provided evidence that $1.31 million was expended in the first five month of 2023. 4 Tr 2827-2828.

Consumers countered that it received materials related to this project in August 2023 and the work will begin in the spring of 2024 (rather than the fall of 2023). 4 Tr 959. Consumers noted that it already agreed to the Staff's bridge period disallowance of $1.493 million, but a $2.58 million investment will be required in 2024 to complete the project. Consumers requested that the Staff's disallowance of $1.493 million be moved to the test year so that the company can complete the project. 4 Tr 959-960.

The ALJ found that Consumers provided adequate support for cost recovery and recommended that the Commission adopt Consumers' proposal to shift the disallowance to the test year in order to allow the company to complete the project, thus approving $2.58 million minus the $1.493 million disallowance for rate base treatment.

In exceptions, ABATE argues that these costs lack specificity and are subject to delay and uncertainty. ABATE's exceptions, p. 4 (citing 4 Tr 959).

In reply, Consumers argues that there is extensive corrosion in the outer casing of the Zeeland plant HRSG, and the remedial work will begin in the spring of 2024. Consumers requests that "the Commission move the portion of the Company's original cost estimate that was taken out of the bridge year (i.e. the $1.493 million) to the test year. 4 TR 960. As a result, the amount that has been requested in this rate case is already known to be below the actual cost that will be necessary to complete this work." Consumers' replies to exceptions, p. 35.

The Commission agrees with the ALJ that the need for this work was adequately supported on the record, and adopts her findings and recommendations.

vii. Zeeland Non-Long-Term Service Agreement Capital Expenditures

This cost category addresses work that is not covered as normal maintenance in Consumers' Zeeland plant LTSA. Consumers projected capital spending of $2.9 million for this project for the bridge period. 4 Tr 887.

ABATE recommended disallowance of the full amount because the company failed to explain how the expenditures were determined and failed to provide historical cost data. 4 Tr 2828. Consumers countered that this project involves known work associated with replacing generator rotating field exchanges on two turbines which will begin in November 2023, and the company will actually spend $3.4 million in the bridge period. 4 Tr 960-961.

The ALJ found that Consumers adequately supported cost recovery for this project and recommended that the Commission approve the $2.9 million request. PFD, p. 120.

In exceptions, ABATE argues that these costs are speculative and no historical cost data was provided by the company. ABATE's exceptions, p. 5.

In reply, Consumers argues that this is known work and is not speculative, and the Staff has recognized the increased cost, and the company agreed with the Staff's adjustment. Consumers' replies to exceptions, pp. 36-37 (citing 4 Tr 960-961).

The Commission agrees with the ALJ that this work is not speculative and adopts her findings and recommendations.

d. Hydroelectric Capital Expenditures

Consumers' 13 hydroelectric dams, which must be operated in compliance with Federal Energy Regulatory Commission (FERC) regulations, are referred to on the record as the river hydro units. Consumers projected capital spending of $36.66 million in the bridge period and $48.89 million in the test year for its river hydro units. 4 Tr 895, 2192.

i. The Hardy Dam

The Hardy dam is of particular interest in the coming years, as it will involve investments of over $350 million through 2027 to meet FERC's dam safety requirements. 4 Tr 2173. While the vast majority of those planned investments are not at issue in this case, a few specific projects at the Hardy dam are in dispute. In the instant case, Consumers projected capital spending related to the replacement of the Hardy auxiliary spillway ($3.45 million in the bridge period and $304,710 in the test year), the replacement of the Hardy splash wall ($625,482 in the bridge period and $3.13 million in the test year), and crest compaction and road replacement ($199,263 in the bridge period and $898,339 in the test year). 4 Tr 2173-2174. Consumers explained that the Hardy auxiliary spillway no longer meets FERC requirements for handling the probable maximum flood and thus requires replacement. Consumers indicated that FERC has reviewed the company's replacement plan but the plan has been delayed by a year, and construction is set to begin in 2025. 4 Tr 2183-2186. Consumers opined that failure to replace the spillway would result in revocation of the project license or decommissioning of the dam, which would have a devastating effect on the economy of the local community.

Regarding the Hardy dam splash wall replacement, Consumers explained that this replacement plan was approved by FERC in 2018, but the work has been delayed in order to coordinate it with the spillway work. 4 Tr 2187-2188. The crest compaction and roadway replacement will take place as part of the project, since the spillway and splash wall work requires the removal of the Hardy dam roadway. Consumers projected that it would receive final approval of the crest compaction and roadway replacement plan from FERC in June 2025. 4 Tr 2189.

The Attorney General argued that, because the future of all of the dams is uncertain and the company is exploring whether to decommission them, the Commission should disallow $18.4

million for total capital spending representing all projects that are not expected to be operational by the end of the test year (which includes the Hardy dam projects). 4 Tr 3122; Exhibit AG-2.2. ABATE also recommended disallowance of all projected capital spending associated with the Hardy dam projects because their completion dates are well beyond the end of the test year. 4 Tr 2830-2831. Consumers countered that the dams are licensed through 2034 and many projects are required in order to remain in compliance with FERC's licensing requirements and to ensure public safety. 4 Tr 2208-2209. Consumers also argued that disallowance of all of the Hardy dam expenditures would be contrary to the terms of the settlement agreement in Case No. U-21224.

The Staff proposed a $1.96 million disallowance for the test year for the Hardy dam projects. The Staff noted that the settlement agreement in Case No. U-21224 limited recoverable capital expenditures related to the Hardy dam projects to costs associated with engineering and the proposed disallowance relates to amounts that do not comport with that requirement. 5 Tr 3822-3827; *see*, January 19 order, Exhibit A, p. 4. The Staff also provided the associated reduction to the allowance for funds used during construction (AFUDC). 5 Tr 3848. Consumers agreed to this disallowance because it would align the projection with the updated cost estimates for completing the engineering work. 4 Tr 2210.

The ALJ recommended approval of the Hardy dam engineering costs for the spillway, splash wall, and crest compaction and roadway work, finding that these costs are in accordance with the terms of the settlement agreement in Case No. U-21224, with the Staff's partial disallowance of $1.96 million (to which the company agreed). PFD, p. 130.

No exceptions were filed and the Commission adopts the findings and recommendations of the ALJ. However, while approving the modest engineering-related costs at issue here for the Hardy dam, the Commission notes that the total estimated costs are significant, and this is an asset that may not be providing generation in the not-so-distant future. The Commission directs Consumers, in its next rate case, to provide a full evaluation of all alternative options, including relicensing and continued operation of the facility, sale of the facility to a third party with and without power generation, and decommissioning of the facility, as well as pricing for the work that the company contends must be done in order to remain in compliance with FERC standards for the Hardy dam, if Consumers seeks any cost recovery in that proceeding related to the Hardy dam work.[5]

ii. The Alcona and Rogers Dams

In addition to the Hardy dam, Consumers planned safety, repair, and replacement projects at the other 12 dams, and stated that 12 bridge period and 13 test year projects have a cost greater than $1 million. 4 Tr 2192-2203. These projects include the replacement of the core wall of the Alcona dam, and the modification or replacement of the spillway at the Rogers dam (also to accommodate the probable maximum flood).

ABATE objected to the Alcona core wall remediation project because it has been delayed, has no project bid or contractor associated with it, and it was unclear on the record whether any amounts would be spent in 2024. ABATE recommended a full disallowance or, in the alternative, a disallowance of $6.57 million, which would leave the company with approval of $4.3 million which is consistent with the CAD. 4 Tr 2829-2831. The Attorney General recommended a disallowance of $5.2 million for the Rogers dam project because it would not be used and useful within the test year. 4 Tr 3106, 3134. Consumers countered that, for projects that are not completed by the end of the test year, the revenue requirement is offset by AFUDC, and these projects are necessary for safety and licensing purposes. 4 Tr 2212-2217. Consumers also argued

[5] The Commission notes that Consumers has already committed to similar reporting requirements in the settlement agreement approved in the January 19 order, Exhibit A, pp. 4-5.

that the CAD is merely a snapshot in time, and noted that the company already accepted the Staff's proposed adjustments to the bridge period and test year. Regarding the Rogers dam project, Consumers also argued that it is necessary for safety purposes, that bridge and test year period funds will be offset by AFUDC, and that the company already accepted the Staff's adjustments.

Starting with the Alcona project, the ALJ found that:

> the project appears to be delayed and the company has not issued a project bid or selected a contractor for the project; thus, it is questionable whether the amount requested will be expended within the bridge period or test year. . . . While engineering costs may be reasonable and prudent to prepare for such a project, funding for the actual project of the replacement itself has not been shown to be reasonable and prudent when the future of the dam is in question. If the company ultimately opts to decommission the dam, it may be more reasonable and prudent to begin the decommissioning process rather than commencing extensive repairs. Accordingly, this PFD recommends a disallowance of the funds associated with the Alcona core wall replacement project, i.e., $9,056,667, to the extent that such funds are for actual construction rather than design and engineering.

PFD, p. 130 (footnotes omitted). Turning to the Rogers dam project, the ALJ similarly opined that the expenditures would not be reasonable and prudent if they were for construction activities rather than engineering and design. She found that Consumers showed that the projected amounts are for design and engineering and recommended that the Commission reject the Attorney General's proposed disallowance for the Rogers project. PFD, p. 131.

In exceptions regarding Alcona, ABATE notes that the ALJ recommended a disallowance of the test year amount to the extent that the funds are for actual construction. ABATE argues that the remaining $1.81 million for the bridge period should also be disallowed. ABATE's exceptions, p. 5. ABATE notes that "Consumers incurred less than $1,000 in the first five months of 2023 and is projected to incur only $21,000 this year, despite the CAD indicating $4.000 million in 2023. (Exhibits AB-16 and AB-17.)" *Id*. ABATE contends that these costs may not materialize. *Id*. (citing 4 Tr 2212-2214).

In exceptions regarding Alcona, Consumers states that its projections for the Alcona core wall remediation are $1.8 million for the bridge period and $9.06 million for the test year. Consumers' exceptions, pp. 43-44 (citing 4 Tr 2192-2198, 2214). Consumers contends that this dam is licensed through 2034 and needs maintenance, and the company expects to receive the FERC's approval of the design in time to start construction in 2024. *Id*. Consumers did not file exceptions addressing the Rogers dam.

In exceptions regarding Rogers, the Attorney General argues that the full amount of $5.17 million (for both time periods) should be disallowed due to the uncertainty about the future of the Rogers dam, in light of Consumers' ongoing evaluation of the company's long-term hydro strategy. Attorney General's exceptions, p. 22. She notes that Consumers "is considering four options for each of its dams: (a) relicensing and continuing to generate electricity, (b) selling the dam to a third party, (c) removing the dam, and ([d]) replacing the dam with an alternative structure that maintains some level of reservoir." *Id*., p. 23 (footnote omitted). Under these conditions, the Attorney General asserts that even investigational spending may be premature.

In reply regarding Alcona, ABATE repeats its argument that Consumers failed to provide a reasonable basis for cost recovery, noting again that "Consumers incurred less than $1,000 in the first five months of 2023 and was projected to incur only $21,000 that year, despite the CAD indicating $4.000 million in 2023." ABATE's replies to exceptions, p. 5 (citing Exhibits AB-16, AB-17).

In reply regarding Alcona, Consumers argues that the CADs are simply a snapshot in time and not representative of actual spending. Consumers' replies to exceptions, p. 37.

In reply regarding Rogers, Consumers argues that it "will perform an evaluation on the new PMF [probable maximum flood] and explore ways to achieve FERC approval of either an Inflow

Design Flood less than the current PMF for the current spillway, an improved spillway, or a replacement spillway in Phase 1. 4 TR 2199." Consumers' replies to exceptions, p. 38. Consumers cites its responsibilities as a dam owner to remain in compliance with FERC requirements and maintain safe operation of its dams as long as they are licensed.

The Commission agrees with ABATE and the Attorney General that the full bridge and test year period amounts should be disallowed for both the Alcona dam and Rogers dam projects. Recognizing that Consumers agreed on rebuttal to certain adjustments proposed by the Staff, the Commission finds that, for the Alcona core wall remediation project, the Commission disallows $1.58 million for the bridge period and $7.053 million for the test year; and for the Rogers probable maximum flood project, the Commission disallows $995,000 for the bridge period and $2.29 million for the test year. While the proposed work does appear to be focused on engineering and design, the Commission is not persuaded on this record that the proposed work is the best option for these river hydro assets given the serious questions about how long the dams will continue to operate. Additionally, the Commission finds that (while completion during the test year is not dispositive of this issue) Consumers did not show that these two projects are far enough along to warrant rate base treatment. *See*, 4 Tr 2192-2199, 2214-2217. Moreover, unlike its presentation on the Hardy dam work, Consumers failed to provide projected total costs for the Alcona and Rogers dam projects. The Commission reminds Consumers that, for future cost recovery requests, the Commission needs a better understanding of the full scope of the work in order to assess individual cost recovery requests against the total expected cost of the project.

e. Solar Generation

The ALJ noted that, in response to the Staff's proposals, Consumers agreed to remove its requested capital expenditures for the Mustang Mile, Washtenaw, and Muskegon Solar projects.

The ALJ further found that, "while additional approvals associated with Washtenaw and Mustang Mile are unnecessary, the company's request for a finding that the Muskegon project costs are reasonable and prudent in the instant case, is rejected. Consumers may present the project for Commission review once a signed agreement has been executed." PFD, p. 132.

In exceptions, Consumers argues that it is not requesting any finding on this project. Consumers' exceptions, p. 44.

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

f. Battery Energy Storage Systems

Consumers proposed capital spending of $1.53 million in the bridge period and $6.02 million in the test year on the Armstrong Battery Energy Storage System (BESS) pilot project. This BESS would be a 2.5 megawatt (MW)/11.5 megawatt-hour (MWh) battery on the distribution system in the City of Battle Creek. The BESS can be islanded, and the company emphasized that the Armstrong BESS will allow Consumers to "explore how to use an islanded battery to quickly restore power to unfaulted sections of the distribution system while faulted zones upstream are being restored." 4 Tr 1158. Consumers indicated that battery procurement activities would take place in 2024 and the BESS would be commissioned in the second quarter of 2025. 4 Tr 1159-1162; Exhibit A-71. The Armstrong BESS project involves testing on just one large commercial customer, and the company estimates that this customer will see an annual reduction of 286 minutes of outage time as a result of the installation of the BESS, which will constitute a 90% improvement in outage time. 4 Tr 1159-1160. Consumers has entered into a contract with the customer and has obtained a 30-year easement from the City of Battle Creek. Consumers argued that the project will enable the company to learn how to safely and effectively deploy battery storage to reduce outages.

The Attorney General proposed a full disallowance of the projected amounts because the record shows that the project is still in the pre-engineering phase, making rate base treatment premature. 4 Tr 2978-2979.

The Staff also recommended a full disallowance due to the limited benefits that the pilot would provide relative to its costs. The Staff noted that the project will require an additional $1.56 million beyond the test year to bring it to completion. The Staff reported that the location of the project is based on the availability of a large behind-the-meter network with solar generation at the site, and a customer with an interest in installing a microgrid. 5 Tr 3829-3831. The Staff stated that this BESS project is not being pursued as a non-wires solution but rather to maintain service to this customer's premises, and outage mitigation will only be available to this single customer. *Id*. The Staff stated that the customer will not be paying for these services and Consumers provided no analysis of the economics of the project. The Staff noted that the primary benefits that appeared to be associated with the project arise from capacity accreditation and energy arbitrage, and neither of these was quantified by Consumers. Thus, the Staff argued that the disallowance is appropriate because of the pilot's limited benefits and the lack of quantitative analysis by Consumers. The Staff indicated its support of deploying battery storage but recommended proposing a pilot that would have the potential to show a reliability benefit for a larger number of customers.

Consumers countered that the pilot has value because the majority of the quantifiable benefits that come out of the pilot will be available to all customers and will come from "the capacity market value associated with 2.5 MW[] of battery energy storage and the energy arbitrage opportunities provided by the 10 MWh of storage." 4 Tr 1168. Consumers argued that this project presents a unique opportunity to test a microgrid on one volunteering customer, and the company, in any case, has no experience with how to charge such a customer for this service. Consumers noted that it included this project as part of a grant application to the U.S. Department of Energy (DOE). On rebuttal, Consumers updated its projected spending to $1.625 million in the bridge period and $4.95 million in the test year, and indicated that commissioning is planned for the fourth quarter of 2025. 4 Tr 1169-1172.

The ALJ recommended that the Commission adopt the Staff's proposed full disallowance. The ALJ noted that the value streams which appear to arise from the pilot (capacity accreditation and energy arbitrage) are unlikely to make up for the cost of the pilot, making the pilot unreasonable for rate base treatment. PFD, p. 145. The ALJ agreed with the Staff that, while there is some value to the potential learnings, the value is not supported by the cost. The ALJ found that "[t]he company has not provided a benefit cost analysis for the pilot and has not quantified the value the Armstrong BESS provide[s] for ratepayers aside from the commercial customer directly receiving the benefits of such." *Id*. Accordingly, the ALJ recommended a full disallowance.

In exceptions, Consumers states that the company:

> considers the experience of developing the necessary expertise to effectively plan and deploy battery-supported microgrids as a significant benefit to all customers. With this project, the Company will develop the skillset needed to extend the islanding use case to sections of the distribution system, where multiple customers can be served from an islanded battery during upstream line or substation outages. 4 TR 1160.

Consumers' exceptions, pp. 45-46. Acknowledging that the project will benefit a single large commercial customer, Consumers argues that the resulting learnings will benefit all customers, as will "the capacity market value associated with 2.5 MW[] of battery energy storage and the energy arbitrage opportunities provided by the 10 MWh of storage. 4 TR 1168." *Id*., p. 46. Consumers notes that the Commission has previously recognized the value of this project, then known as the Fort Custer project, in the December 17, 2020 order in Case No. U-20697, p. 39.

In reply, the Attorney General argues that anytime Consumers "is putting a value on a project to obtain recovery in rates, it should be required to justify how those dollars directly benefit ratepayers, otherwise it is unreasonable to require ratepayers to pay the costs." Attorney General's replies to exceptions, p. 40.

Despite involving just one commercial customer, the Commission agrees with Consumers that the learnings will be of benefit to all customers and the Commission continues to support this project (which used to be known as Fort Custer) under its new name. *See*, December 17, 2020 order in Case No. U-20697, pp. 37-40. The Commission reiterates that while full implementation of a pilot at scale is strengthened by showing a positive BCA and a benefit to all ratepayers, implementation of the pilot itself does not need to be accompanied by the same showing; and the Commission recognizes that the proffered BCA was performed prior to finalization of the criteria adopted in Case No. U-20898. The Commission reminds the company of the cautions laid out in the December 22 order, pp. 59-60, and notes that it will continue to rely on the criteria developed in Case Nos. U-20645 and U-20898. But the Commission finds merit in this proposal. In particular, the Commission finds that Consumers provided sufficient evidence on this record of the potential benefits that could accrue from the Armstrong BESS including how to use an islanded battery to restore power. 4 Tr 1158-1162. The Commission agrees with Consumers that, for the company "to learn how to safely and effectively deploy battery storage to reduce avoidable outage minutes for the customers, it is imperative to begin the deployment and testing of this storage application[] now." 4 Tr 1160. The Commission notes that the company has entered into a contract and obtained the required easement, and has made other necessary investments. 4 Tr 1159. The Commission approves the requested bridge period and test year funding for the Armstrong BESS for rate base treatment, and encourages Consumers to continue to seek federal funding for these types of efforts as described in the February 23, 2023 order in Case No. U-21227.

4. Facilities Capital Expenditures

This cost category is included within Electric Operations Support and contains several projects. 4 Tr 1434; Exhibit A-12, Schedule B5.5; Exhibit A-96. The ALJ addressed disputed projects, as discussed below.

a. Service Center Projects

Consumers projected capital spending of $5.55 million in the bridge period and $12.73 million in the test year for new construction to the Lansing and Hastings Service Centers, and for renovations to the Kalamazoo Service Center. 4 Tr 1447-1464, 1471-1477.

The Attorney General proposed disallowances for all three service center projects, noting that all have experienced significant delays and labor/material shortages. Beginning with the Lansing Service Center, the Attorney General noted that the project was approved in the December 22 order, but has since been reconfigured and the projected cost has been reduced. In the instant case, Consumers projected capital spending of $3.7 million in the bridge period and $6.4 million in the test year. 4 Tr 3122-3124. The Attorney General noted that although the Commission approved expenditures of $13.6 million for 2022 in the December 22 order, p. 162, Consumers actually spent $311,000 in 2022 on the Lansing Service Center. *Id*. The Attorney General argued that this project is still in the early stages and the timing remains uncertain, and the full amount should be disallowed.

Turning to the Hastings Service Center, the Attorney General again notes that the project was approved in Case No. U-20963, has been delayed and reconfigured since that time, and the total cost has been reduced. In the instant case, Consumers projected capital spending of $580,000 in the bridge period and $815,000 in the test year. 4 Tr 3125-3126. The Attorney General noted that although $5.7 million was approved for rate base treatment for this project in 2022, the company actually spent $2,880. *Id*. The Attorney General argued that this project is still in the early stages and the timing remains uncertain, and the full amount should be disallowed.

The Attorney General made identical arguments with respect to the Kalamazoo Service Center, noting that Consumers projected capital spending of $1.3 million in the bridge period and $5.5 million in the test year. 4 Tr 3127-3128. The Attorney General recommended a full disallowance because the project is still in the design phase. The Attorney General's adjustments for the three service centers totaled $5.55 million in the bridge period and $12.73 million in the test year. 4 Tr 1494.

Consumers countered that these projects have been delayed but are now progressing and the company provided updates at 4 Tr 1494-1495. Consumers reduced the projected 2023 capital spend for Hastings to $189,000. 4 Tr 1497. Consumers also noted that the Staff does not oppose the projects.

The ALJ found that:

> [a]s an initial matter, the reasonableness and prudence of the service centers is not in dispute. In Case No. U-20963, the Commission agreed with the ALJ that the replacement of the three service centers was reasonable and prudent, and it approved costs of $3.83 million in 2021 and approximately $35 million in 2022. Despite the company's compelling presentation in that case, most of the funds were not spent, and the service centers are still pending initiation if not completion.

PFD, p. 150 (footnote omitted). The ALJ recommended that the Attorney General's proposed disallowances be approved (noting the reduction to the Hastings bridge period amount). The ALJ found that:

> [t]he company's timetable over the past several years has continued to slip; the scope of work has changed, and while it was appropriate to remove the costs for the Hastings Service Center, the PFD finds that, based on the current status of these projects, the ever evolving timeline, and the changes in plans and expenditures since 2020, Consumers should request cost recovery for these projects in a future rate case when the service centers are closer to completion.

PFD, pp. 150-151. The ALJ recommended a full disallowance of $5.55 million for the bridge period and $12.73 million for the test year for all three service centers.

In exceptions, Consumers argues that it continues to execute this service center work pursuant to the Commission's approval in Case No. U-20963, and the work should be funded. Consumers' exceptions, pp. 59-61. Consumers asserts that the work at the three service centers will result in lowered operational costs, better response times for customers, and improved operations. Consumers reiterates that the company has agreed to reduce the proposed capital expenditures for the bridge period from $543,000 to $189,000. Consumers notes that no other party recommended a disallowance, and contends that a total disallowance is not warranted.

In reply, the Attorney General argues that these projects are not past the development and design stage, and the costs and timelines for the projects have changed since their approval. Attorney General's replies to exceptions, p. 51.

The Commission adopts the findings and recommendations of the ALJ. As the Attorney General and the ALJ point out, previously approved amounts were not spent, and meanwhile the costs, timeframes, and scope of work have changed for all of these projects. While the Commission is not rejecting Consumers' long-term plans for the service center rebuilds, the projects presented on this record do not appear to be ready for rate base treatment.

b. Electric Vehicle Infrastructure Project

The ALJ indicated that this issue is discussed below in Fleet Services Capital Expenditures. PFD, p. 151.

5. Fleet Services Capital Expenditures

Consumers presented its fleet electrification plan, which involves replacing 30% of its internal combustion engine (ICE) vehicles with EVs by 2030. 4 Tr 1076-1084. Consumers proposes to purchase 19 Chevrolet Silverado EVs for the test year and install sufficient chargers at various locations. 4 Tr 1086-1098. Because the EVs are approximately $43,000 higher in price per truck than ICE trucks, the company projects capital spending of $0.822 million on vehicles and $1.2 million on charging infrastructure. *Id*. Consumers stated that the plan will result in lower fuel and maintenance costs and reduced carbon emissions.

The Attorney General recommended a full disallowance, arguing that Consumers' current ICE trucks are still reliable and EVs will likely become cheaper in the future. 4 Tr 3128-3129. MNSC did not recommend a disallowance, but argued that the company likely overstated the long-term cost of electrification. MNSC argued that the Commission should ensure that future rates deliver savings to customers associated with fleet electrification. 4 Tr 2660-2662. Consumers countered that EV availability is tight, making delay risky. The Staff countered MNSC's proposal, saying that it sounded like a tracking mechanism, which the Staff opposes.

The ALJ found that Consumers failed to justify the EV purchases, which would replace "currently reliable ICE vehicles. This PFD agrees that the replacement of these vehicles would have minimal decarbonization benefits and ratepayers would benefit if such purchases were delayed to a time when EVs are closer in price to ICE vehicles." PFD, p. 154. The ALJ recommended a full disallowance for both the EV purchases and the charging infrastructure of $0.8 million and $1.2 million, and agreed with the Staff that a tracker is not advisable. *Id*.

In exceptions, Consumers argues that the PFD is mistaken, because the company revised its infrastructure cost projection to $250,000 for the 12 months ending December 31, 2023. Consumers' exceptions, pp. 61-62 (citing 4 Tr 1497-1498). Consumers requests approval of the revised amount. Consumers also argues that the ALJ's recommendation regarding the EV purchases fails to consider the company's purchasing strategy. Consumers contends that it is "replacing units that have reached their end of life. 4 TR 1084." Consumers' exceptions, p. 62. Consumers points out that it used the same replacement process that is used for all vehicles, and that, when a unit is considered for replacement, the unit is also considered for replacement with an EV. Consumers asserts that its purchase plan will lower the company's reliance on fossil fuels, lower its fuel and maintenance costs, and lower its overall greenhouse gas emissions. Consumers also notes that no party presented evidence as to when the alleged future EV cost reductions would occur, and points out that these Silverado EVs are the only units available to Consumers in 2023.

In reply, the Attorney General argues that despite the lowered infrastructure cost request, the Commission should adopt the ALJ's recommendations. She further contends that simply because a unit has reached the end of life for depreciation purposes does not mean that the unit is no longer useful. Attorney General's replies to exceptions, p. 53. She argues that these purchases will have little decarbonization benefit and EV costs will trend lower in the future.

The Commission disagrees with the ALJ and finds that the EV purchases for the company's fleet should be funded along with the $250,000 request for EV charging infrastructure for 2023. The Commission finds that Consumers adequately supported its contention that its fleet electrification plan will result in lower fuel and maintenance costs. While issues involving a tracking mechanism were raised by the Staff, the Commission finds that these concerns are misplaced, that no tracking mechanism was proposed, that savings attributable to the fleet transition can be accounted for in the same way as savings from any other company investment, and that no exceptions were filed on this issue. Furthermore, even putting aside the asserted benefits of lower carbon emissions, the projected savings on fuel and maintenance are sufficient to support this investment, and the Commission therefore approves the proposed $822,000 for vehicle purchases and $250,000 for infrastructure expenditures. The Commission again encourages Consumers to monitor federal funding and tax credit opportunities that support these types of investments.

6. Information Technology Expenditure

In support of its IT capital expenses, Consumers testified that its current challenges center around supporting and securing aging IT systems; building new technology capabilities to further the company's IRP, EDIIP, and customer plans; and maintaining affordable rates. 4 Tr 2481. In 2022, Consumers' actual electric allocation of capital expenditures was $36,699,000. The company projected $41,351,000 in the 14-month bridge period and $38,495,000 in the test year. 4 Tr 2507-2508; Exhibit A-12, Schedule B-5.11. The following make up the contested IT issues.

a. Customer Self-Service Mobile Application

Citing the popularity, efficacy, and customer benefits of the company's self-service mobile application (mobile app), Consumers further developed the mobile app in response to customer feedback by implementing additional usability and reliability and enhancing the customer experience. Thus, Consumers requested $37,816 in 2022 capital expenditures for development and implementation of the mobile app. The Staff recommended a full disallowance for 2022 for the mobile app, equating to a $21,000 reduction to rate base, arguing that a disallowance is consistent with Commission precedent and is appropriate given that the mobile app offers technology that is duplicative of technology already available on the company website. 5 Tr 3919-3920; Staff's initial brief, pp. 43-44. The company disagreed with the Staff's proposed disallowance. Consumers' initial brief, pp. 157-161.

The ALJ agreed with the Staff's disallowance reasoning that the company's testimony demonstrated that the mobile app's functions are duplicative of the functions of the company's website and that Consumers did not present any evidence regarding how often the company website is down or the other avenues customers may use during such an outage. PFD, pp. 164-165. The ALJ was also convinced by the Commission's previous disallowances of Consumers' expenditures for the mobile app that were pointed out by the Staff. Finding that the company failed to demonstrate the reasonableness and prudence of the mobile app expenditures, the ALJ accordingly recommended that the capital in the amount of $37,816 for 2022 should be disallowed, as well as the requested costs for 2022 within the Enhancements-CX&O-Capital project, totaling $1,773,050. *Id*. Additionally, the ALJ recommended that the costs that were included for the mobile app within the Product Family Enhancements-Customer Capital Projects of $254,360.33 for the two months ending February 29, 2024, and $1,526,162 for the test year should be disallowed. The ALJ also recommended a disallowance of the $49,044 in projected IT operation O&M expense for the mobile app. While noted here, this O&M expense is discussed below.

Consumers takes exception and argues that the ALJ failed to acknowledge that the company's evidence supporting the customer mobile app is more robust than evidence in previous cases. Consumers repeats its previous testimony regarding the growth of customer usage of the mobile app and then argues that the ALJ's recommended disallowance based on her finding that the mobile app is duplicative of the website is without merit. Pointing to testimony on the record, Consumers states that it acknowledged that the functions of the mobile app and the website are similar but argues that this is by design and allows customers to choose communication means based on their needs. The company further contends that it currently has multiple transaction and communication channels (i.e., its interactive voice response system, website, mobile app, call centers, and direct payment offices) that exist simultaneously to meet different customer preferences. The company then reiterates the streamlining and efficiency qualities of the mobile app that distinguish it from the website to conclude that the ALJ's reasoning is not valid and that the Commission should allow full recovery of the company's expenditures for the mobile app. Consumers' exceptions, pp. 47-50.

The Commission respectfully declines to adopt the PFD and finds that recovery of Consumers' capital expenditures for the customer self-service mobile app is appropriate in this case. As noted by the ALJ, the Commission has previously disallowed these expenditures in Case Nos. U-20963 and U-20697. However, in the December 22 order, the Commission agreed with the ALJ in that case that a disallowance was appropriate because the project's cost data had first been presented in rebuttal testimony and therefore, the whole project was not justified in the company's direct case. December 22 order, pp. 139-140, 142. Similarly, in the December 17, 2020 order in Case No. U-20697 (December 17 order), the Commission agreed with the ALJ that the mobile app was presented too late in the proceeding for the parties to fully evaluate it and, thus, found a disallowance to be appropriate. December 17 order, p. 132. Further, Consumers' most recent general electric rate case, Case No. U-21224, was resolved by a settlement agreement meaning that the Commission did not make a decision on the merits of the mobile app. *See*, January 19 order, p. 6 (approving the settlement agreement).

Therefore, the Commission's previous disallowances have been for reasons other than the merits of the mobile app. As stated by the ALJ, in Case No. U-20963, the company was given the opportunity to demonstrate the reasonableness and prudence of these expenditures in a future rate case. The Commission finds that the company has demonstrated the reasonableness and prudence of the mobile app expenditures in the instant case by presenting convincing evidence that the mobile app's usage is growing, from 504,000 downloads in May 2023, to 726,920 downloads in September 2023, and that the mobile app is now the second most popular means of communication with a significant number of transactions completed on the mobile app since its inception. 4 Tr 1518, 1543-1544. The Commission agrees with the company's arguments that, while there may be some redundancy in the functions of the app and the website, there is value in offering varying communication channels to meet customer needs. As pointed out by Consumers in its exceptions, it could be argued that there is redundancy between the functions of call centers and the company's website as both are avenues to receive customer payment. As technologies and customer preferences evolve, the Commission finds that duly supported, reasonable, and prudent expenditures to meet those preferences are appropriate for recovery.

Thus, the Commission finds reasonable the recovery of $37,816 in the historical year, as well as the associated IT expenses of $1,773,050 for the Enhancements-CX&O-Capital Project; $254,360 for the two months ending February 29, 2024, in the bridge year, and $1,526,162 in the test year for the Product Family Enhancements-Customer Capital Projects; and $340,425 in Flexible and Advance Payment Options in bridge year.[6] Consistent with this decision, the

[6] The $349,425 associated with the Flexible and Advance Payment Options was omitted from the ALJ's recommendation but should be included with the IT costs associated with the mobile app.

Commission finds that the $49,044 in associated O&M expenses should be recovered, as discussed below. As with any other expenditure, however, continued recovery in future rate cases is dependent upon a satisfactory demonstration that the project is reasonable and prudent.

b. Bill Design and Delivery Transformation Project

Consumers explained that billing is the largest interaction point for the company and its customers and that the current in-house billing system is "outdated and limited" resulting in operational inefficiencies, billing defects, and customer dissatisfaction. 4 Tr 1529. According to the company, the Bill Design and Delivery Transformation (BDDT) project will alleviate these issues by:

> 1) outsourcing the flexible print and delivery pieces of bill processing, thus reducing overall risk and cost while providing a more efficient means to modify and target messages within outbound printed materials, 2) replacement of existing software for print correspondence management with a more efficient and cost-effective vendor-hosted solution; and 3) a bill redesign for the most common Company rates and rate/program combinations.

4 Tr 1530. Anticipating that the project will begin in January 2024 with new bills delivered in June 2025, Consumers requested $2,966,361 in capital expenditures in the test year for the BDDT project along with an associated $521,625 in O&M expense that is addressed below.

The Attorney General recommended an approximate $2.9 million disallowance for the test year citing the company's estimated -0.482 benefit-cost ratio. 4 Tr 3130 (referencing Exhibit A-181, p. 44). The Staff recommend a total disallowance of $296,636 of capital expenditures in the bridge period, and $2,373,088 of capital expenditures in the test year, explaining that the Staff has recommended a full disallowance in Consumers' last two electric and gas rate cases and, apart from settlement agreements that resolved three of those cases, the Commission agreed with the Staff's disallowance in the December 22, 2021 order in Case No. U-20963. Noting that it already removed 20% of the original project capital costs and O&M costs, the Staff's disallowance came to a total of $2,669,726.06 in capital expenditures and $417,300 in O&M. 5 Tr 3922-3923; Exhibit S-18.2. Consumers disagreed with the Attorney General's and the Staff's proposed disallowances. 4 Tr 1550-1551.

The ALJ agreed with the Staff's disallowance, finding it to be supported by the Attorney General's position as well. The ALJ stated that while the company made a reasonable case that the purpose of the project is to reduce cost, that reduction was not reflected in the company's evidentiary presentation. The ALJ elaborated as follows:

> Reviewing Revised Exhibit A-181, p. 44, the total cost of the BDDT project is $15.510 million, with the majority of the costs incurred in 2025. This compares to an estimated benefit of $13.102 million. Although the company points to alleged unquantifiable benefits, "such as avoided costs, safety, quality, and the reduction of outage duration of these projects" some of these benefits, such as avoided costs, could in fact be quantified (if they apply). The company also states that "[Attorney General witness] [Dr.] Dismukes's recommendation ignores the evidence in this case showing that the main alternative to this project would be to incur $16 million annually in O&M costs that would be required if the Company continued trying to accomplish this billing work through the use of its currently outdated system" referencing Revised Exhibit A-181, p 44. A significant annual savings in O&M costs would appear to provide ample justification for the BDDT project, but this amount is not reflected in the cited exhibit, which shows O&M savings of approximately $2.5 million per year from 2025-2028.

PFD, pp. 170-171 (footnote omitted). Thus, the ALJ recommended a disallowance of $296,636 of capital expenditures in the bridge period, and $2,373,088.93 of capital expenditures in the test year. *Id*., p. 171. The ALJ addressed the associated O&M costs in the Net Operating Income section on page 417 of the PFD.

Consumers excepts and disagrees with the ALJ's finding that the reduction in costs was not reflected in the company's presentation and states that the ALJ explicitly discussed those cost reductions. The company notes that the ALJ seems to have accepted the company's $500,000 in annual savings but rejected the $16 million in annual O&M savings that Consumers would incur if it continued billing work on its outdated system. The company disagrees with the ALJ that the

$16 million was not reflected on page 44 of Exhibit A-181, stating: "[a]lthough it was not included in calculating the benefit-cost ratio at the bottom of that document, it was clearly shown as the cost of keeping the Company's existing bill delivery process the same (i.e. the cost of continuing with the status quo) under the [']Alternatives['] heading in the [']Work Objectives['] portion of the exhibit." Consumers' exceptions, p. 51. Therefore, the company insists that it did quantify these savings. Lastly, the company reiterates the improved billing experience that will result from the BDDT project before asking the Commission to approve the company's capital expenditures for this project. *Id*., p. 52.

In her reply to exceptions, the Attorney General repeats that the BDDT project has a -0.482 benefit-cost ratio, that the company's exhibits show only $2.5 million in O&M savings, and that the project is in preliminary stages and thus, premature for inclusion in rates. Attorney General's replies to exceptions, p. 43.

Finding the ALJ's recommendation to be well-reasoned and supported by the record, the Commission adopts the PFD. The Commission agrees with the ALJ that the savings demonstrated by the company show a $2.5 million annual O&M savings in the years 2025 through 2028. The company's exceptions again assert that the savings amount is $16 million but do not explain why its Exhibit A-181 shows the savings to be $2.5 million annually for those years. Therefore, the Commission is not persuaded that recovery is appropriate given the benefit-cost ratio demonstrated on this record and the inconsistency of the company's claimed savings. *See*, 4 Tr 3130; Exhibit A-181, p. 44.

c. Other Information Technology Adjustments

The Attorney General recommended the following disallowances in other areas of Consumers' IT capital expenditures: (1) $1,912,811 disallowance for the Catastrophic Crewing Database

Replacement project; (2) $2,127,841 disallowance for the Core Applications Always On for Business; (3) $687,031 disallowance for HVD Operations Digital Work Management project; (4) $340,759 disallowance for the Customer Order Service Tracker project; (5) $183,786 disallowance for the Customer Work Request Web Portal; (6) $588,169 disallowance for the Digital Data and Analytics in the Cloud project; and (7) a $1.7 million disallowance and $2.6 million disallowance in the bridge and test years, respectively, for the Asset Refresh Program-Workstation Management project (ARP-WAM). 4 Tr 3107; PFD, pp. 171-172.[7]

The ALJ adopted some of the Attorney General's recommended disallowances and recommended recovery on others as described below.

i. Catastrophic Crewing Database Replacement Project

Beginning with the Catastrophic Crewing Database Replacement project, the ALJ adopted the Attorney General's disallowance and reasoned that Consumers provided only one example of a significant storm in August 2023 where it brought in 650 crews that challenged the company's existing IT system for scheduling lodging. The existing system and the fact that the cost of the company's proposed system exceeds the benefits led the ALJ to conclude that a disallowance is reasonable. PFD, pp. 172-173. Therefore, the ALJ recommended a $1,912,811 disallowance for the project.

[7] As noted in footnote 662 of the PFD, these proposed disallowance amounts listed in the Attorney General's testimony did not reflect the 20% rough order of magnitude (ROM) adjustment that was included in the company's revenue requirement. Consumers explains that it "uses the term 'ROM' to characterize an initial estimate that includes research, analysis, and a business case[,]" and the company included "a 20% reduction for those projects whose projections are based on a ROM." 4 Tr 2516-2517. As the ALJ did on pages 171-172 of the PFD, this order lists the recommended disallowance amounts inclusive of the ROM reductions.

Consumers excepts to the ALJ's recommended disallowance for the catastrophic crewing database replacement stating that, "[n]ow, more than ever, the Company needs to be able to effectively manage the many, many crews called upon to restore power quickly when severe weather strikes." Consumers' exceptions, p. 52. Relying on its testimony, Consumers first notes that its projected expenditures included a 20% reduction and while it appreciates the ALJ taking that into account, her disallowance was unfounded. Further disputing the ALJ's reasoning, Consumers contends that its current IT system has not kept pace with the company's efforts to onboard and deploy more off-system electric crews that require lodging. Consumers then argues that the -1.000 benefit-cost ratio does not account for avoided service restoration or saved SAIDI minutes, which the company testified would be approximately $4.7 million in avoided service restoration costs and save 44 SAIDI minutes. *Id.*, pp. 53-54. Lastly, Consumers contends that the alternatives to the Catastrophic Crewing Database Replacement project either perpetuate inefficiencies or are impractical, and therefore, asks that the Commission approve this expenditure. *Id.*, pp. 54-55.

In her replies to exceptions, the Attorney General repeats her previously stated arguments in support of a disallowance and asks the Commission to adopt the PFD. Attorney General's replies to exceptions, p. 45.

The Commission respectfully declines to adopt the ALJ's recommendation and instead finds that Consumers has demonstrated that its proposed capital expenditures on the Catastrophic Crewing Database Replacement project are reasonable and prudent in this instance. While the Attorney General focused on the negative benefit-cost ratio for this project, the company presented evidence that additional benefits result in the form of the 44 SAIDI minutes saved and $4.7 million in avoided service restoration costs. *See*, 4 Tr 1711-1712. Given the importance of service restoration, which the Commission has emphasized in recent dockets[8] and in its rule changes to the Service Quality and Reliability Standards, Mich Admin Code, R 460.722, and the increasing frequency of severe storms that necessitate larger than normal restoration crews, the Commission finds that expenditures in this instance to improve the company's restoration efforts are reasonable. However, the Commission encourages the company to include all quantifiable benefits in its benefit-cost ratio such that evaluation of a project includes the weighing of all costs and all benefits.

ii. Core Application Always On For Business Project

As to the Core Application Always On For Business project, the ALJ recommended approval of the $2,127,841 in capital expenditures citing the fact that this project impacts other key company operations like the ADMS that operates continuously. PFD, p. 174.

The Attorney General excepts to the ALJ's recommended approval for this program and argues that the ALJ's decision did not focus on the economic analysis which proved the program is not reasonable or prudent. The Attorney General pointed to the -1 benefit-cost ratio to argue that the Commission should remove the $2.7 million in capital expenditures. Attorney General's exceptions, pp. 23-24.

In its replies to exceptions, Consumers asserts that the Attorney General's exceptions focus only on the economic analysis while the ALJ properly considered other benefits, notably that the

[8] Several Commission dockets have recently addressed or are currently dedicated to grid reliability and resiliency. Some of these dockets include Case No. U-21305 (opened to address utilities' response to August 2022 severe weather events), Case No. U-21388 (opened to address utilities' response to February 2023 severe weather events), Case No. U-20147 (addressing utilities' distribution plans), and Case No. U-21400 (opened to consider proposals for penalties or incentives to utilities related to service outage metrics).

project will: "(1) increase availability of the website; (2) reduce planned interruptions to critical business operations; (3) reduce planned downtime for customer contact centers; and (4) increase business partner productivity and eliminate workarounds." Consumers' replies to exceptions, p. 39 (citing 4 Tr 2586). The company also notes that it already agreed to a reduction in the project's costs meaning that the amount recommended for approval is likely less than the actual amount needed. Therefore, the company asks the Commission to adopt the PFD. Consumers' replies to exceptions, pp. 39-40.

Finding the ALJ's recommendation to be well-reasoned and supported by the record in this case, the Commission adopts the PFD. The Commission agrees that the company has demonstrated the reasonableness and prudence of the $2,127,841 in test year expenditures and that the impacts on other areas of operations justify recovery in this case. *See*, 4 Tr 2517, 2585-2586, 2600-2603.

iii. High Voltage Distribution Operations Digital Work Management

The ALJ recommended that the Commission adopt the Attorney General's proposed disallowance of $687,031 for the HVD Operations Digital Work Management project explaining that the company's evidentiary presentation of the project was vague and lacked sufficient detail to demonstrate the intent of the project or whether it is essential at this time. PFD, pp. 174-175.

Consumers excepts to the disallowance for the project arguing that the company provided sufficient evidence that the project will increase efficiency and accuracy. The company repeats that when considered against other alternatives, including doing nothing, the HVD Operations Digital Work Management project is necessary to improve Consumers' work management process. Consumers' exceptions, p. 55.

The Attorney General responds to the company's exceptions arguing that Consumers' repetition of vague descriptions of the project is unpersuasive and that the "jargon filled descriptions lacks [sic] detail about the true nature of the project and its necessity." Attorney General's replies to exceptions, p. 46. Thus, the Attorney General asks the Commission to adopt the PFD. *Id*., p. 47.

Finding the ALJ's recommendation to be well-reasoned and supported by the record, the Commission adopts the PFD on this issue. If the company seeks to recover capital expenditures for HVD Operations Digital Work Management in the future, it must provide sufficient detail to justify the expenditures and demonstrate the reasonableness and prudence of the project. The Commission agrees with the ALJ and Attorney General that in this case the company's evidentiary presentation was vague and lacking in detail.

iv. Customer Order Service Tracker and Customer Request Web Portal

Addressing the Customer Order Service Tracker and the Customer Request Web Portal together, the ALJ recommended that the $340,759 for the Customer Order Service Tracker Project and the $183,786 for the Customer Work Request Web Portal be included in rate base. The ALJ noted that the Attorney General did not address the company's rebuttal regarding the reductions in calls resulting from the implementation of a similar program for C&I customers. However, the ALJ added that the Commission should caution Consumers that reductions in call center costs due to reduced call volume should be reflected in future rate cases. PFD, pp. 175-176.

The Attorney General excepts to the ALJ's recommendation and her comment that the Attorney General did not respond to the company's rebuttal on this issue. The Attorney General argues that Consumers' rebuttal on the issue was not persuasive. Per the Attorney General, "[p]resumably the Company quantified the expected reduction in calls for the proposed projects and included it in its cost [sic] cost-benefit analysis (at least it should have)." Attorney General's exceptions, p. 26. The Attorney General concludes that the negative BCAs for the projects speak for themselves and that the Commission should disallow the $0.43 million in capital expenditures for the service order status tracker and $0.23 million in capital expenditures for the portal that allows customers to originate and view the status of new business service and alteration requests. *Id*., pp. 24-26.

In its replies to exceptions, Consumers states that the Attorney General's proposed disallowance focused solely on the economic analyses while the ALJ gave credit to the company's testimony regarding the reduction in calls to the call centers and improved customer experience. Consumers repeats its testimony regarding the benefits of the programs, asserts that the ALJ properly recognized these benefits with her recommendation, and notes that the Commission's decisions often involve policy choices, meaning the Commission should also recognize these benefits that Consumers has supported on the record. Further the company notes that it agreed to the ROM reduction for this cost so the actual costs of the projects may be less than the amount approved. Consumers' replies to exceptions, pp. 41-42.

Finding the ALJ's recommendation to be well-reasoned and supported by the record in this case, the Commission adopts the PFD. The Commission notes its agreement with the ALJ that any reductions in call volume and, in turn, call center costs, attributable to this project should be reflected in future rate cases.

v. Digital-Data and Analytics in the Cloud Project

Turning to the Digital-Data and Analytics in the Cloud project, the ALJ recommended approval of the company's expenditures of $588,169, stating that although the company did not show a net benefit for the program, the alternative of increasing the functionality of the in-house program at a higher cost was persuasive that the digital-data and analytics in the cloud project was reasonable. PFD, p. 177.

The Attorney General excepts to the ALJ's recommended expenditures approval arguing that Consumers should not be permitted to recover a return and depreciation expense for this project because it is premature and produced a negative BCA ratio. Attorney General's exceptions, pp. 26-27.

Responding to the Attorney General's exceptions, Consumers states that the Attorney General repeats arguments from her testimony and briefing but does not address the ALJ's reasoning. Consumers repeats its description of the project and its benefits and states that the ALJ correctly found that the alternative of procuring these capabilities on-site for just one use case would be costlier. Citing the Attorney General's failure to respond to the ALJ's reasoning, Consumers asks the Commission to adopt the PFD. Consumers replies to exceptions, pp. 42-44.

Finding the ALJ's recommendation to be well-reasoned and supported by the record in this case, the Commission adopts the PFD on this issue. Given the higher cost alternative and the company's demonstration that its proposed project is reasonable and prudent to support the company's data analysis needs, recovery of the $588,169 in test year capital expenditures is appropriate. *See*, 4 Tr 2586-2587, 2602.

vi. Asset Refresh Program-Workstation Asset Management

Lastly, the ALJ recommended adoption of the Attorney General's proposed disallowance of $1.7 million disallowance and $2.6 million disallowance in the bridge and test years, respectively, for the ARP-WAM project, reasoning that:

> based on Consumers' incident data, there was a fairly even number of incidents in 2022 based on the age of the equipment, with the largest number of incidents occurring with two-year-old equipment with fewer incidents occurring with four-year-old equipment compared to three-year-old equipment, as shown in

> Ms. Weller's graph at 4 Tr 2550. This [ALJ] also finds it puzzling that in an organization the size of Consumers, a reserve of computers is not maintained for employee use in the event that a unit requires repair. In that case, productivity losses could be minimized while machines are repaired.

PFD, p. 179.

As to the ARP-WAM project, Consumers takes exception to the ALJ's recommended reduction and states that the ALJ misunderstood the information presented in Consumers' graph provided in testimony, which showed the hardware incidents for personal computers or field devices in 2022. Consumers clarifies the data provided in the graph and accompanying testimony as follows:

> However, [Consumers witness] Ms. Weller's testimony immediately before this graph stated that the Company only has 725 devices that are four years old or more out of a total population of 12,399 devices. 4 TR 2549. That means that the Company's devices four years old or more are only 5.8% of all devices but they experience 23.4% of all of the Company's incidents. Ms. Weller also explained that almost 38% of the devices four years old or more had incidents that needed to be resolved. 4 TR 2549. Using the data discussed above, it is possible to calculate that 11,674 of the Company's devices are less than four years old (12,399 total devices – 725 devices four years old or more). Even if it is assumed that each incident reported in the graph above affected a different device, i.e. there was no individual device that experienced two or more incidents (which is a very conservative assumption), the data from the chart would indicate that only 25% of devices less than four years old experienced an incident. However, it is much more likely that, when there is a defective device less than four years old, that individual device probably experiences multiple incidents before it is entirely replaced, which would reduce the percentage of newer devices experiencing an incident even further. Either way, the percent of incidents in devices less than four years old is significantly less than the percent of incidents in devices four years old or more.

Consumers' exceptions, pp. 56-57. Consumers claims that the proper interpretation of the information in the graph supports a four-year replacement cycle. As to the ALJ's comment questioning why a reserve of computers is not maintained in the event a repair is needed, Consumers argues that the record makes no such suggestion, and that Consumers does have computers on hand for temporary use but that such a reserve does not solve the productivity problem related to computer failure described in the company's testimony. Thus, the company argues that the expenditures for this project are reasonable and should be recovered in full. *Id*., pp. 57-59.

In her replies to exceptions, the Attorney General argues that the PFD does not support the company's assertion in its exceptions that the ALJ misunderstood the company's evidence and testimony. The Attorney General states that the ALJ merely noted the number incidents per age of equipment as the company's graph indicates and that there is no indication that the ALJ assumed anything about the number of devices involved. The Attorney General adds that the company speculates that it is more likely when there is a defective device less than four years old, that device will experience multiple incidents. Such speculation, according to the Attorney General, demonstrates a lack of analysis by Consumers to support its four-year refresh cycle. Thus, the Attorney General recommends adoption of the PFD. Attorney General's replies to exceptions, pp. 48-49.

The Commission respectfully declines to adopt the ALJ's recommendation. The Commission finds that in this instance Consumers has provided sufficient evidence to support its four-year replacement cycle with specific information regarding the number of incidents occurring in the different age brackets of its equipment. Specifically, the Commission is persuaded by the company's evidence regarding the number of failures; devices four years old or more are only 5.8% of all devices but make up 23.4% of all the company's incidents. Consumers also explained that almost 38% of the devices four years old or more had incidents that needed to be resolved. *See*, 4 Tr 2549. The company also demonstrated that it adequately considered alternatives to extend the replacement cycle and found such alternatives to be unreasonable given the negative impacts that include the increased risk of hardware failure and equipment outages, poor function of applications, increase to the replacement cycle in future years, and a potential inability to apply security patches. *See*, 4 Tr 2548-2553. Therefore, the Commission approves the company's full cost recovery of its capital expenditures and the $94,575 in O&M, which is discussed below.

7. Security Capital Expenditures

The Staff recommended a 20% adjustment to Consumers' proposed security capital expenditures resulting in capital expenditures in the amount of $115,464 for 2023, $28,788 for the 2-months ending February 29, 2024, and $172,728 for the projected test year based on the Staff's opinion that project cost projections based on ROM estimates are not sufficiently precise to warrant full recovery at this time. Consumers' initial brief, p. 185 (citing 5 Tr 3909-3910). The company did not oppose the Staff's reduction. Consumers' initial brief, p. 185. Considering the company's concession, the ALJ recommended that the Staff's position be adopted. PFD, p. 179.

Having no exceptions filed on this issue and finding the ALJ's recommendation to be well-reasoned and supported by the record, the Commission adopts the PFD. Therefore, the Commission adopts the 20% adjustment to Consumers' proposed security capital expenditures resulting in capital expenditures in the amount of $115,464 for 2023, $28,788 for the 2-months ending February 29, 2024, and $172,728 for the projected test year.

8. Demand Response Capital Expenditures and Recommendations

Consumers requested recovery of capital expenditures in the amount of $7.1 million for the company's DR programs for the projected test year. Consumers' initial brief, pp. 185-186; Exhibit A-12, Schedule B-5.8. The company's residential DR programs consist of Device Cycling, Dynamic Peak Pricing, which includes Critical Peak Pricing and Peak Time Rewards, and Residential Smart Thermostat. Consumers' business DR programs include the Smart Thermostat for small-medium business and the Small Business Generator pilots, C&I Contractual DR, which includes the GI and GI2 rate provisions, Rate EIP, and Long-Term Industrial Load Retention Rate, all of which are described in the company's testimony. *See*, 4 Tr 2088-2107. Consumers also projected O&M costs for the test year to be $41.3 million, which includes O&M expenses of $17,325,000 for the C&I DR program, $4,875,000 for the SMB DR program, and $19,050,000 for the residential DR program. Consumers' initial brief, p. 392.

The Staff did not make any adjustments to Consumers' projected capital or O&M expenditures but recommended that the Commission direct Consumers to file an updated calculation of its DR credits in its next general rate case that includes the latest estimate of cost of new entry (CONE) and updated values of expected per-customer load reduction for credits that are administered monthly (e.g., the residential air conditioning recycling program), and to include actuals rather than expected values whenever possible. 5 Tr 3671; Staff's initial brief, pp. 179-180; *see also*, PFD, pp. 181-182. The Staff also recommended that the company review DR credit calculations for all rates and perform an update in its next rate case, if necessary, to which the company agreed. 3 Tr 218.

Noting that no other party addressed the company's capital or O&M expenditures for DR and that "no party took issue with the proposed operation of the DR programs, the company's proposed modifications, or the discontinuation of some pilots[,]" the ALJ recommended that the Commission approve Consumers' projected DR capital and O&M expenditures, as well as the company's modifications to its DR programs and pilots. PFD, p. 182.

Having no exceptions filed on this issue and finding the ALJ's recommendation to be well-reasoned and supported by the record, the Commission adopts the ALJ's recommendation to approve the $7.1 million in DR capital expenditures for the projected test year, as well as the $41.3 million in O&M, which are discussed in below. Like the ALJ, the Commission also adopts the Staff's recommendation and directs the company to file an updated calculation of its DR credits in its next general rate case that includes the latest estimate of CONE and updated values of expected per-customer load reduction for credits that are administered monthly (e.g., the residential air conditioning recycling program), and to include actuals rather than expected values whenever possible, as described on pages 179-180 of the Staff's initial brief.

9. Customer Experience Capital Expenditures

Consumers projected a CX&O of $310,000 in the bridge period. 4 TR 1502-1504; Exhibit A-12, Schedule B-5.6.

While noting that there was some dispute regarding certain CX&O IT project costs, no party objected to the instant CX&O capital expenditure. Therefore, the ALJ recommended that the company's request should be approved. PFD, p. 182.

Having no exceptions filed on this issue and finding the ALJ's recommendation to be well-reasoned and supported by the record, the Commission adopts the PFD on this issue. As to the dispute of some CX&O IT projects referred to by the ALJ, the Commission references its decision discussed *supra* to approve the company's proposed cost recovery for the mobile app and the associated IT expenses of $1,773,050 for the Enhancements-CX&O-Capital Project.

10. Corporate Services Capital Expenditures

Consumers projected capital expenditures of $653,000 in the bridge period and $572,000 in the test year for Corporate Services explaining that these expenditures include Governmental, Regulatory/Public Affairs, Legal, Risk Management, Chief Financial Officer, General Activities, and Administration among other costs that are shared between the company's electric and gas sides. 4 Tr 1353-1355; Exhibit A-12, Schedule B-5.4.

Finding that no party objected to the company's capital expense projection, the ALJ recommended that these expenditures be approved. PFD, p. 183.

Having no exceptions filed on this issue and finding the ALJ's recommendation to be well-reasoned and supported by the record, the Commission adopts the PFD.

11. Electric Vehicles Capital Expenditures and Program Recommendations

a. PowerMIDrive and PowerMIFleet

Consumers projected $5.511 million and $3.064 million in capital expenditures in the bridge and test year, respectively, along with deferred O&M costs of $41.780 million from 2020 until the end of the test year. Exhibit A-12, Schedule B-5.9. Projecting approximately 500,000 EVs in its service territory by 2030, the company proposed to continue its transportation electrification (TE) program[9] with modifications and no rate increases to support off-peak charging and system upgrades by tailoring annual TE program budgets to align with the rate of EV adoption. The company proposes to continue regulatory asset treatment of the TE program budget. 4 Tr 2229-2230.

For PowerMIDrive (PMD), Consumers proposed to shift the pilot's focus from fast charging infrastructure to strategic off-peak Level 2 locations and Level 1 long-duration locations. The program would offer up to a $7,500 rebate per 100 amps of at least two plugs providing Level 2 charging on a TOU rate at overnight destinations (i.e., hotels, resorts) and a $7,500 rebate per 100 amps of at least five plugs providing Level 1 charging on a TOU rate at long-term parking

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[9] In the presentation of its case, Consumers uses "TEP" for the term transportation electrification program, while the Commission uses "TEP" for the term transportation electrification plan. *See*, *e.g.*, December 21, 2023 order in Case No. U-21538 (December 21 order). To draw a distinction between these two terms, transportation electrification plans refer to utility-wide plans to electrify the transportation system, namely with a focus on EV adoption and grid adaptation. Transportation electrification program, as used by Consumers represents individual programs that are components of the company's overall transportation electrification plan. For the purposes of this order, TEP will refer to a transportation electrification plan.

locations (i.e., airports, train stations). The program also includes community charger centers with a $7,500 rebate per 100 amps of various Level 1, Level 2, or National Electrical Manufacturers Association 14-50 plug charging configurations on a TOU rate if they reserved overnight parking for EVs and were located within two blocks of a multi-dwelling unit or an underserved community. 4 Tr 2222, 2226, 2230, 2232-2234.

For the PowerMIFleet (PMF) program, Consumers proposed to adjust the focus of the program to sectors of the economy requiring the greatest assistance, namely, schools, public transit, non-profits, local governments, and small- to medium-sized businesses. PMF will focus on off-peak Level 2 and longer-duration direct current fleet charging opportunities, in addition to off-peak Level 2 workplace charging. 4 Tr 2235. Rebates ranging from $7,500 up to, if certain conditions are met, $10,000 would be offered under the program for various charging scenarios. 4 Tr 2235-2236.

The Staff supported Consumers' proposals for the PMD and PMF programs as well as the company's plan for biannual meetings with interested persons and reporting. 5 Tr 4117. The Attorney General argued that the TEP costs are excessive and benefit only a small number of customers and questions the accuracy of the $254 million NPV projected by the company. With these concerns the Attorney General recommended that the Commission remove all test year capital expenditures in the amount of $3,064,000 for the TEP as well as the $13,786,000 in deferred O&M. The Attorney General also objected to the company's third-party fleet electrification assessments and asked the Commission to ensure that these costs are borne by EV fleet customers only. 4 Tr 2988-2991.

METC supported making the PMD and PMF programs permanent but recommended that Consumers be required to engage with METC to discuss ways that EV adoption will affect the transmission system. 4 Tr 3348, 3350. MNSC and MEIBC/IEI/United supported the company's proposed TEP programs but argued that its proposed intention to prioritize and waitlist rebates if rebates exceeded the company's TEP budget was unnecessary due to the deferral of EV charging expenditures. 4 Tr 2659; 5 Tr 3452-3453. MEIBC/IEI/United also recommended that rebate amounts be revisited in general rates cases and that rebates for direct current fast chargers (DCFC) under the PMD program should be extended and increased, or in the alternative, that Consumers develop a make-ready infrastructure program to support charging stations. MEIBC/IEI/United further suggested that Consumers be required to prepare and provide available on-line load capacity maps for DCFC developers. 5 Tr 3456-3459. Walmart asked that the Commission require Consumers to include C&I customers in its PMD public charging program and in its PMF program. 5 Tr 3580. The CEOs recommended that Consumers establish an inclusive utility investment program that expands upon that of DTE Electric's eFleet Battery Support program, and that Consumers commit to finance at least five batteries in their service territory. 5 Tr 3341-3342.

The ALJ recommended approving Consumers' proposed spending and modifications to the PMD and PMF programs as well as its proposal for biannual meetings to receive input from interested persons on the programs. Acknowledging that the Attorney General's concerns had some merit, the ALJ nevertheless reasoned that the TEP is relatively new and the regulatory landscape around EVs is rapidly evolving. Thus, the ALJ recommended that the Commission and interested parties continue to scrutinize the TEP's assumptions, costs, and benefits in future rate cases. However, the ALJ did agree with the Attorney General that fleet assessment costs should be borne by the potential fleet customer, not by all customers. PFD, p. 203. The ALJ also noted her agreement with Consumers' approach to setting a budget for the rebate programs and prioritizing or waitlisting applicants if demand exceeds supply, explaining that the company's budget can be readjusted in the future. *Id*., p. 201.

Turning to the intervenors' recommendations, the ALJ declined to adopt MEIBC/IEI/United's recommendations for Consumers' pilots to be networked and that the EV programs should be reoriented toward DCFCs or make-ready rebate programs. The ALJ explained that the networking requirement would increase the costs of chargers when other solutions are available and that the company's purpose in implementing its EV programs is to develop a skeleton network to overcome range anxiety; therefore, the company's focus on Levels 1 and 2 chargers is reasonable. The ALJ noted that Consumers stated that it may reconsider its focus on DCFCs. *Id*., p. 202. However, the ALJ agreed with MEIBC/IEI/United's suggestion that rebate levels should be revisited in each rate case, although she noted she agreed more with the Staff's reasoning than MEIBC/IEI/United's reasoning. Noting that the Commission has already required the same of DTE Electric, the ALJ also agreed with MEIBC/IEI/United that Consumers should be required to prepare and make available on-line load capacity maps to assist third-party developers in determining suitable locations for DCFC hubs. *Id*., p. 202 (citing the November 18 order, p. 338 (requiring DTE Electric to provide third parties with hosting capacity maps)).

While declining to recommend a new forum for discussions and agreeing with Consumers that regular plan filings and proceedings like the IRP exist to formally assess such matters, the ALJ encouraged Consumers to engage with METC as needed to discuss EV adoption on the transmission system. PFD, p. 203. As to Walmart's recommendation, the ALJ declined to recommend that large C&I customers be included in the PMD or PMF public charging programs. As the company explained, such customers are not necessarily excluded and may be eligible for PMD rebates under some circumstances and the company's decision to direct these programs towards the sectors most in need is reasonable since larger customers are likely already better positioned to handle the EV transition. *Id*. Lastly, the ALJ declined to adopt the CEOs' recommendation to require Consumers to develop an inclusive utility investment program for transit bus batteries similar to DTE Electric's eFleet battery support pilot. She reasoned that such a decision rests with utility management and that, while it would be welcomed, the company's expressed preference is to avoid financing EV components and instead encourage EV bus adoption through other means such as rebates. *Id*., pp. 203-204.

MEIBC/IEI/United except to the ALJ's recommendation that the PMD and PMF budgets should be limited and that applicants to the programs should be waitlisted if demand exceeds supply, calling the recommendation unreasonable. MEIBC/IEI/United's exceptions, pp. 2-3. Adding to its previous arguments, MEIBC/IEI/United argue that the plan to readjust rebates periodically in the future may result in a series of "fits and starts" where customers race to claim rebates to avoid being waitlisted. *Id*., p. 2. MEIBC/IEI/United contend that any negative impact from oversubscription is unlikely or is less severe than the negative impacts on EV-charging customers will be if a waitlist is implemented. Therefore, MEIBC/IEI/United ask the Commission to reject the PFD. *Id*., p. 3.

Turning to the ALJ's comment that she agreed more with the Staff's reasoning than MEIBC/IEI/United's reasoning regarding adjusting rebates in the future, MEIBC/IEI/United except, arguing that it is unlikely that rebates will support EV adoption if they are reduced. MEIBC/IEI/United recall its testimony that rebates must keep pace with the increasing costs of charging infrastructure. Further, as the company projects significant net revenue from EV adoption, MEIBC/IEI/United ask the Commission not to endorse a trajectory for rebates that puts the projected resulting benefits at risk. *Id*., pp. 3-4. Next, MEIBC/IEI/United take exception to the ALJ's finding that the company's shifted focus to Levels 1 and 2 chargers is reasonable. MEIBC/IEI/United repeat previous testimony that the managed charging benefits are greater from focusing rebates on Level 2 chargers and DCFCs, that these benefits outweigh the benefits from Level 1 charging, and that it makes little sense to focus rebates on Level 1 chargers. MEIBC/IEI/United contend that the Commission should direct Consumers to extend the DCFC rebate funding. *Id*., pp. 4-5. Lastly, MEIBC/IEI/United argue that the ALJ's recommendation against requiring Level 2 chargers and DCFCs is contrary to the evidence MEIBC/IEI/United presented in this case and that the ALJ did not provide a reasoned basis for rejecting MIEU's rebuttal to Consumers' arguments. MEIBC/IEI/United state that, in violation of Sections 81(2) and 85 of the Michigan Administrative Procedures Act, MCL 24.201 *et seq*., the ALJ also failed to provide a reasoned basis for her finding that EV telematics would operate comparably. MEIBC/IEI/United argue that in presenting a sufficiently reasoned opinion supported by the record, the Commission can only conclude that networked chargers are more versatile, dependable, and economical. MEIBC/IEI/United's exceptions, pp. 5-7.

The CEOs take exception to the ALJ's rejection of the CEOs' proposal for Consumers to adopt an inclusive utility investment for EV bus batteries. Repeating the position that they set out on the record and briefing, the CEOs ask the Commission to encourage Consumers to adopt a program similar to that adopted by DTE Electric to defray higher upfront costs of EV batteries and to spur electrification of the transportation sector. CEOs' exceptions, p. 6.

The Attorney General excepts to the ALJ's recommended approval of the company's programs and spending arguing that the ALJ "is putting the cart before the horse" by endorsing increased spending for programs that benefit few customers on the hope that enough EVs will be purchased to support the company's math. Attorney General's exceptions, p. 29. Repeating her position on the issue, the Attorney General also contends that the record produced no credible evidence that nearly a third of Consumers' customers will own EVs by 2030 and, therefore, the Attorney General's suggested disallowances should be adopted by the Commission. *Id*., pp. 29-30.

Although generally agreeing with the ALJ's recommendations, Consumers takes exception to a few aspects of the ALJ's reasoning and recommendations for PMD and PMF. First, Consumers repeats its position that rebate levels should be revisited every three years rather than the annual basis recommended by the Staff and MEIBC/IEI/United and adopted by the ALJ. Consumers' exceptions, pp. 65-66. Next, Consumers disagrees with the ALJ's statement that the fleet assessment costs should be borne by fleet customers and argues that the benefits from the fleet assessment will pass to many customers, not just fleet customers. Therefore, Consumers asks to maintain its current assessment structure for the time being. *Id*., p. 67. Lastly, while not excepting to the ALJ's recommendation, the company asks for clarification from the Commission as to the level of detail sought in the hosting capacity maps. *Id*.

In response to MEIBC/IEI/United's exceptions regarding setting limits on rebate budgets, the Staff argues that it fully addressed this issue in briefing and that the ALJ considered the whole record on this issue. The Staff contends that MEIBC/IEI/United's disagreement with the ALJ does not amount to an error and therefore, the Commission should adopt the PFD. Further, the Staff addresses MEIBC/IEI/United's assertion in exceptions that reduced rebates will not support EV adoption and supports the ALJ's decision. The Staff states that this does not support increasing rebates because: (1) the impetus for EV infrastructure does not rest solely on the utility or its customers and (2) programs should be designed to maximize ratepayer benefits. Staff's replies to exceptions, pp. 17-18. Lastly, the Staff repeats its arguments that the company's shift in focus to

Level 1 and Level 2 charging is reasonable and contends that the Commission should reject MEIBC/IEI/United's argument to focus rebates on fast charging. *Id*., p. 18.

MEIBC/IEI/United respond to the Attorney General's assertions regarding the benefits of EV to all customers and the NPV of EVs per customer, contending that the Attorney General's benefit-cost calculation does not compare apples to apples and artificially inflates per-customer costs. MEIBC/IEI/United illustrate the Attorney General's flaw as follows:

> The language used gives this away, in that the [Attorney General]'s Exceptions refer to the net present value ("NPV") calculation as calculated on a "per vehicle/customer" basis while its cost calculation is calculated on a "per customer" basis. It appears that the [Attorney General] actually means "per rebate recipient" when using the terms "per customer" and "each EV customer," given that the ~$6,700 figure results from dividing the $53,658,000 of overall program costs by the 7,990 rebates the [Attorney General] projects will be distributed by the end of the test year. By contrast, the [Attorney General] divides the projected NPV from EV charging revenue ($254[million]) by the average number of all EVs the Company projects to be charging on its system from 2023 to 2030 (207,897), resulting in a per-vehicle NPV of $1,220. By dividing the NPV and costs by two different values (i.e., NPV by the average number of charging vehicles and costs by the number of rebates), the [Attorney General] has created an apples-to-oranges comparison, which artificially and inappropriately increases the estimated costs and makes them appear much larger than the projected benefits.

MEIBC/IEI/United's replies to exceptions, pp. 2-3 (footnote omitted). MEIBC/IEI/United add that the rebate benefits extend beyond rebate recipients, pointing to public locations like grocery stores or multi-family dwellings as examples, and that the Attorney General acknowledged the broad value for expenditures in EV program education, thus recognizing that benefits extend beyond rebate recipients. *Id*., pp. 3-4. Lastly, MEIBC/IEI/United refute the Attorney General's allegation that the ALJ is "putting the cart before the horse" and states that, while rate cases are based on projections, there is substantial and reliable evidence on this record to support the company's NPV, budget, and growth for its EV programs. *Id*., pp. 4-5.

MEIBC/IEI/United also respond to Consumers' implication in exceptions that the Commission has no authority to direct Consumers to impose certain conditions or requirements on its rebate programs. MEIBC/IEI/United clarify that while the Commission cannot make management decisions for the company, the Commission has rate-making authority and therefore, the Commission should not be persuaded by the company's management arguments when considering MEIBC/IEI/United's recommendations for chargers to be networked or for rebates to focus on fast chargers. *Id*., pp. 5-6.

In her replies to exceptions, the Attorney General responds to Consumers' assertion that the fleet assessment should not be paid by fleet customers because the benefits will flow to all customers. The Attorney General argues that the company failed to present any evidence in support of its benefits claims and contends that Consumers did not show that the $25,000 fleet assessment cost is prohibitive to potential fleet customers. The Attorney General therefore asks the Commission to adopt the PFD. Attorney General's replies to exceptions, p. 54.

In its replies to exceptions, Consumers addresses the Attorney General's exceptions and argues that the Attorney General's disallowance remains unfounded. Consumers recounts its testimony regarding federal and state goals for EV adoption and the EV growth rate in Consumers' territory and contends that the Attorney General did not respond to this evidence. While not disputing its current EV count, Consumers argues that the current number does not speak to the growth rate, which is a low-growth scenario recognized by other parties to this case. Consumers also defends its NPV with its previous testimony and argues that the Attorney General's comparison of the NPV per vehicle being less than the amount Consumers is spending on each EV customer is not a sound comparison. Consumers states that, "[t]he NPV already accounts for the costs of EV charging. To analyze costs and benefits on a per-vehicle basis, the appropriate comparison is between the amount to be recovered from customers and the Company's cost." Consumers' replies to exceptions, p. 47. Nevertheless, Consumers asserts that despite the cost of the programs proposed in this case, 90% of the value projected in Consumers' last rate case, Case No. U-21224, will remain. *Id*.

Turning to MEIBC/IEI/United's exceptions opposing the company's proposal to set a budget for the PMD and PMF program and prioritizing or waitlisting customers as demand requires, Consumers dismisses MEIBC/IEI/United's concern that doing so would result in a series of fits and starts. Consumers states that this would only be a concern if the company did not budget enough to meet the current demand for rebates, which it has based on a low-growth EV scenario. Next, addressing MEIBC/IEI/United's recommendations for Level 1 rebates to be reduced, Consumers repeats its reasoning provided in testimony for the focus on Level 1 chargers and states that it may revisit DCFCs in the future. *Id*., pp. 47-49. As to MEIBC/IEI/United's recommendation for networking Level 2 and DCFCs, the company repeats that it does not anticipate stress on the grid from EV charging to be a problem in the next three years and that EV supply equipment as a solution is expensive and may pose reliability challenges. Defending the ALJ's recommendation, Consumers states that the Level 2 network issue was not a question that had to be answered in this case, the ALJ dedicated several pages of the PFD to testimony and arguments on the networking issue, the ALJ cited to the company's testimony and argument in support, and the ALJ cited to a similar rejection of networking chargers in another Commission order. Consumers' replies to exceptions, p. 50 (citing PFD, pp. 188, 191, 194, 196-197, 201-202, footnote 788). Consumers maintains that the Commission should, therefore, adopt the PFD. *Id*., p. 51.

Next in its replies to exceptions, Consumers responds to the CEOs' exceptions regarding an inclusive utility investment program modeled after DTE Electric's eFleet battery support program. Consumers argues that this is a decision that rests with the company's management. Consumers contends that the CEOs did not dispute the ALJ's findings but continue to ask for the Commission to encourage implementation of such a program. Consumers maintains that such a decision rests with the company. *Id.*, p. 52.

The Commission agrees with the ALJ's recommendations for the approval of the PMD and PMF programs, Consumers' proposal to utilize a waitlist and application of a limited budget based on Consumers' projected EV growth, the capacity map to be provided by Consumers, the rejection of Walmart's proposal to include large C&I customers in the public charging programs within PMD and PMF, and rejection of the CEOs' proposal for an inclusive utility investment program. The Commission finds these recommendations to be well-reasoned and supported by the record in this case and therefore, adopts the PFD on these issues. Further, the Commission adopts the ALJ's recommendation for approval of Consumers' projected capital expenditures in the test year and continued regulatory asset treatment. *See*, Exhibit A-12, Schedule B-5.9.

However, the Commission takes this opportunity to comment further on certain aspects of the adopted recommendations. First, while it is appropriate to address cost recovery, accounting treatment, and rebates for the PMD and PMF programs in general rate cases, the Commission finds that filing the company's TEP and any associated reports including those pertaining to its TE program, discussed further below, in a separate docket is preferable given the large volume and tight time constraints of general rate cases. Therefore, the Commission directs Consumers to file its TEP and associated reports in Case No. U-21538[10] to allow for more holistic consideration of

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[10] Case No. U-21538 was a docket opened on the Commission's own motion for the receipt of certain regulated utilities' TEPs. In the December 21order opening the docket, the Commission directed only DTE Electric to file its TEP but noted that the docket would remain "open for the potential filing of TEPs from other regulated electric utilities at a future date." December 21 order, p. 2.

the details of these programs not necessarily related to dollar amount recovery. Consumers' TEP should be filed no later than July 1, 2024. Consumers shall serve a copy of its TEP filed in Case No. U-21538 on the parties to the instant rate case proceeding. Additionally, the Commission finds that the development of a TEP is well-served with input from interested persons. Therefore, the Commission directs Consumers to build upon its collaborative efforts and to hold at least two public meetings with interested persons to allow for input on the TEP prior to the filing of the TEP.

With respect to the company's proposal to prioritize rebates or utilize a waitlist for demand that exceeds the limited budget for the PMD and PMF programs, the Commission finds persuasive Consumers' testimony and arguments on this issue. Consumers has based its budget for the program on conservative estimates of EV growth, which the Commission finds reasonable given that EV adoption is an evolving field. As such, the Commission also agrees that these programs' expenditures and rebate amounts should be continually evaluated in future rate cases to account for these changes. In addition to evaluating rebate amounts, Consumers shall follow up on its commitment expressed in this record to evaluate penetration levels for DCFCs. Additionally, the Commission directs the company to conduct a load shape study for DCFCs as well as Level 2 chargers and to evaluate whether it is appropriate for these chargers to have separate tariffs. The company shall include its findings in its next general electric rate case.

As to the waitlists, the Commission cautions the company that waitlists should be avoided if possible and, in order to keep abreast of changes in EV adoption growth patterns, the Commission directs Consumers to include in its TEP filing in Case No. U-21538 an update on the company's projections and actuals of EV adoption as well as any resulting impacts to the TEP.

In its exceptions, Consumers asked for clarification regarding the additional details to be included in capacity maps that will assist third parties in determining the best EV charging locations. The Commission points Consumers to the November 18 order in DTE Electric's previous rate case, where the Commission similarly adopted a recommendation to provide capacity maps; the September 8, 2022 order in Case No. U-20147; and the Commission's Distribution System Data Access workgroup where the Commission has discussed the details for such capacity maps. Additionally, as the company noted in its exceptions, the recent Grid Integration Study was filed in Case No. U-21251 (the docket related to the Distribution System Data Access workgroup) on June 30, 2023 (June 30 Grid Integration Study) and contained details on capabilities that could be integrated into these maps. While the company currently provides capacity maps online, discussion around improvements to the data and capabilities of these maps has progressed in the dockets mentioned above and in the June 30 Grid Integration Study. Such improvements include displaying more granular data and enabling bi-directional hosting capacity maps. Therefore, the Commission refers Consumers to pages 43 through 54 of the June 30 Grid Integration Study, with attention to the following recommendations regarding specific elements that could improve Consumers' existing capacity maps:

> • Include color grading for developers to identify circuits with higher capacity. This can be in two parts – one for generation, the other for load.
>
> • Include DERs in-progress with markers of appropriate sizes. These markers would be helpful in showcasing which areas are getting more interconnection requests.
>
> • Address voltage levels in the circuit topology landing page. Voltage levels provide an additional parameter for developers to gauge the circuit's capacity (lower voltage levels such as 4.8 kV circuits usually have more grid-constrained scenarios for future looking DER interconnections, compared to higher voltage levels such as 13.2 kV).
>
> • Use downloading features for highlighted data/circuit segments.

June 30 Grid Integration Study, pp. 48-49.

Turning to the fleet assessment costs, the Commission respectfully declines to adopt the ALJ's recommendation that these costs should be borne by fleet customers exclusively. Rather, the Commission is persuaded that the company's position to maintain its current fleet electrification assessment structure more appropriately aligns with the approved treatment of other study costs and the relative early stages of the PMF program. The Commission is also persuaded that the benefits of fleet electrification extend beyond the potential fleet customer, which further lends support to maintaining Consumers' current structure. However, the Commission expects Consumers to evaluate continually the benefits of fleet electrification and whether the current assessment structure remains appropriate. The company should fully support its rationale in future rate cases.

b. Rate GP and Demand Charge Holiday

The Staff testified that Consumers' Rate GP is a general service primary rate with no demand charge that is open only to DCFC charging stations for new customers whereas the company's Rates GPD and GPTU are general service primary rates with demand charges. The Staff explained that Consumers offers a demand charge holiday for EV charging that currently does not have an end date. Thus, the Staff proposed that the demand charge holiday extend until June 1, 2026, and that any DCFC energized after June 1, 2024, can remain on Rate GP for two years. At the end of the demand charge holiday, the DCFCs would be moved to their choice of Rate GPD or Rate GPTU. 5 Tr 4094, 4097-4099.

Consumers conceded that the Staff raised some interesting points but contended that the demand charge holiday should merely be revisited in 2026 rather than discontinued in 2026. Consumers' initial brief, pp. 209-210. Arguing that ending the demand charge holiday could unreasonably raise costs for typical high load factor customers taking service under those rates, ABATE proposed that the Commission and Consumers should investigate whether it is appropriate for DCFCs to have a separate tariff rate, to which the Staff agreed. 4 Tr 2791-2792; Staff's reply brief, p. 36.

The ALJ agreed with the Staff's proposal to extend the demand charge holiday until June 1, 2026, and allow any DCFC energized after June 1, 2024 to remain on Rate GP for two years. The ALJ also agreed with ABATE, however, that instead of compelling DCFCs to eventually take service under Rate GPD or GPTU, the DCFC could have a distinct load profile that justifies a separate tariff. Therefore, the ALJ recommended that the Commission direct Consumers to investigate and study whether a separate tariff for DCFCs is appropriate and present the results of such study in its next rate case. The ALJ further noted that the Commission addressed a similar issue in DTE Electric's most recent rate case, Case No. U-21297, and that the Commission opted to extend the demand charge holiday and direct a study to determine whether a separate rate for fast chargers was appropriate. PFD, pp. 206-207 (referencing the December 1 order, pp. 341-342).

Consumers excepts to the ALJ's agreement with the Staff regarding the rolling demand charge holiday. Consumers repeats its recommendation that the demand charge holiday should be revisited in 2026 to determine whether it should continue or not because it is premature to set a sunset date two years from now. Consumers' exceptions, pp. 66-67.

In its replies to exceptions, the Staff supports the ALJ's decision and notes that the ALJ explained that her decision was based on the Staff's analysis. Thus, the Staff asks the Commission to adopt the PFD. Staff's replies to exceptions, pp. 16-17.

MEIBC/IEI/United address the demand charge holiday in its replies to exceptions, supporting the company's recommendation in its exceptions that the demand charge holiday should be revisited in 2026. MEIBC/IEI/United agree with Consumers' position, citing the rapidly evolving nature of fast charging and asks the Commission to modify the Staff's proposal to align with the company's recommendation. MEIBC/IEI/United's replies to exceptions, pp. 6-7.

Finding the ALJ's recommendation to be well-reasoned and supported by the record, the Commission adopts the PFD. As noted in the previous section, the Commission is supportive of the recommendation for Consumers to evaluate the merits of a separate tariff for DCFCs, as well as for Level 2 chargers. Consumers shall file the results of its study on this matter in its next general electric rate case. The Commission expects that consideration of the merits of a separate tariff for DCFCs will likely involve consideration of the ongoing need for a demand charge holiday beyond June 1, 2026. If the study of a DCFC tariff supports extending this deadline, Consumers may file for approval of such an extension in a future rate case.

c. Electric Vehicle Contribution in Aid of Construction Waiver

Consumers sought a waiver from Mich Admin Code, R 460.511, part of the Commission's Underground Electric Line rules, which states that a customer must make a CIAC payment to the utility in an amount equal to the estimated difference in cost between overhead and underground facilities. The company explained that it sought this waiver for its PMD and PMF programs because the programs facilitate EV adoption and provide benefits to the electric grid. 4 Tr 2240-2241. The Staff opposed the waiver because Consumers did not quantify the cost that would be borne by other customers in subsidizing undergrounding for chargers. 5 Tr 4036. Stating that it was unclear whether the company sought a permanent or temporary waiver, the Attorney General recommended approval of only a temporary waiver if deemed necessary. 4 Tr 2991-2992.

Noting that Consumers clarified in rebuttal that it seeks only a temporary waiver that would only apply until make-ready funds previously approved by the Commission for TEP pilots are expended, the ALJ found the issue to be resolved. PFD, p. 209 (referencing 4 Tr 2252, 2247;

Consumers' initial brief, p. 209). Thus, the ALJ recommended approving the temporary waiver since the Staff and the Attorney General do not oppose it.

Having no exceptions filed on this issue and finding the ALJ's recommendation to be well-reasoned and supported by the record, the Commission adopts the PFD. The Commission agrees with the ALJ that Consumers' clarification regarding its intent for a temporary waiver rendered the Staff's and the Attorney General's concerns moot, thus resolving the issue.

d. Electric Vehicle Circuit Hosting Studies

After a study of four of its LVD circuits to determine the effect of a potential increase in EV charging, Consumers found that three of its four circuits would not need upgrades to serve EVs through 2027 with the success of off-peak charging programs. However, the fourth circuit would need upgrades even with the primarily off-peak load growth. 4 Tr 2013-2015. The Staff recommended that Consumers conduct a similar study on a broader scale stating that it would be useful in determining the upgrades that may be needed and the costs of such upgrades can be incorporated into the company's BCA for EV programs. 5 Tr 4034. Consumers responded that it is developing a methodology to do an expanded, but still limited, set of studies that could be generalized to the rest of Consumers' LVD system. 4 Tr 2056-2057.

The ALJ agreed with the Staff and recommended that the Commission encourage the company to continue to develop and perform an expanded study of the LVD system that could be representative of the whole LVD system. PFD, p. 210.

Consumers did not take exception to the ALJ's recommendation but states that it will continue to work on an expanded study that could be generalized to the rest of its LVD system. Consumers' exceptions, pp. 67-68.

Noting that Consumers and no other party takes exception to the ALJ's recommendation and finding the PFD to be well-reasoned and supported by the record, the Commission adopts the PFD. The Commission encourages Consumers to continue its work on the expanded study as it has indicated in this case. The Commission further encourages Consumers to investigate whether managed charging programs may be suitable as cost-effective non-wires alternatives to LVD upgrades in specific areas to manage near-term load growth and propose managed charging programs that could be offered to customers willing to participate.

12. Accumulated Provision for Depreciation

The ALJ explained that the differing amounts presented by Consumers, the Attorney General and the Staff for the accumulated provision for depreciation arise from each party's different position in net plant projections. Based on her recommendations discussed above and represented in Attachment B to the PFD, the ALJ arrived at an accumulated provision for depreciation of $5,838,846,000. The ALJ noted that this balance should be made consistent with the Commission's final decisions in this matter. PFD, p. 210.

Consistent with the Commission's decisions described above, the Commission finds appropriate an accumulated provision for depreciation of $5,824,483,000.

B. Working Capital

Consumers initially projected a working capital amount of $3,044,903,000, which it modified to $3,023,600,000 on rebuttal, conceding to two adjustments recommended by the Staff and the Attorney General. However, while adopting the Staff's and the Attorney General's adjustments, the company also recommended a $58,800,000 increase to working capital based on the full impact of the historical balance updates related to accrued taxes, to which the Staff and the Attorney General agreed. Staff's initial brief, p. 8; Attorney General's initial brief, pp. 101-102.

Accounting for all adjustments, Consumers' proposed working capital amount is $3,004,692,000. Consumers' initial brief, pp. 219-220; revised Exhibit A-187, line 8, column (g).

Within working capital, Consumers proposed a cash balance amount of $53.7 million. Consumers used a 13-month average period ending March 31, 2022, to estimate its cash balance. The company explained that it did not use the 13-month period ending December 2022, which would have aligned with the historical year in this case. The company explained that doing so would include a period with a natural gas price spike that resulted in an unusually low average cash balance and that its proposed 13-month period reflected normal cash balance levels. 4 Tr 736-737.

The Attorney General recommended another adjustment to the company's cash balance portion of projected working capital in response to Consumers' arguments that a higher balance was warranted due to a natural gas price spike in 2022. The Attorney General recommended that the Commission adopt a $30.4 million average cash balance for the six months ended June 2023, which represents a $23.3 million reduction from Consumers' proposed amount of $53.7 million, and results in a total working capital amount of $2,916,000,000. 4 Tr 3049-3051; Exhibit AG-1.33; Attorney General's initial brief, pp. 96-97.

The ALJ rejected the Attorney General's proposed adjustment pointing to the company's rebuttal testimony where it demonstrated that the use of only six months of cash balances for projecting the test year working capital requirement for cash on hand is inappropriate considering the seasonal variation in revenues. The ALJ further noted that Consumers demonstrated that using a 13-month period other than the historical year has been uncontested in cases where there were significant disruptions during the historical period. Lastly, the ALJ agreed with Consumers that the use of 1% of revenues as a benchmark for working capital cash is not arbitrary. PFD, pp. 215-216.

The Attorney General takes exception. First, the Attorney General states that the ALJ addressed only the Attorney General's cash balance adjustment. Next, the Attorney General insists that she demonstrated that using the six-month period ending June 2023 to project cash balance needs is reasonable because:

> Monthly cash balances from January 2021 through June 2023 shows that after December 2022, cash balances remained relatively low, averaging to $30.4 million for the six-month period ending June 2023 and $22.2 million for the 13 months ended June 2023 for the portion allocated to the electric business. The average balance for the six months ended June 2023 is somewhat higher than the 2022 historical average balance of $20.1 million, but significantly lower than the average balance of $53.7 million for the 13-months proposed by Mr. Bleckman. The first six-months of 2023 includes most of the period (spring and summer) in which the Company claims to hold more cash, so the Attorney General's proposal is consistent with the Company's needs without the extra $1.8 million burden for ratepayers.

Attorney General's exceptions, p. 32. Next, the Attorney General contends that the use of a 13-month period in the past does not justify its use here. The Attorney General repeats her arguments that the company's cash spikes in April, July, and August of 2021 and January 2022 seem to be related to financing transactions from long-term debt issuances and equity cash injections and are not representative of ongoing cash needs. *Id*., p. 33. Lastly, the Attorney General again disputes Consumers' use of a ratio of 1% of revenue to gauge sufficient cash balances and states that the company did not demonstrate a correlation between 1% of its revenue and the items impacting its cash needs. Thus, the Attorney General asks the Commission to reduce Consumers' working capital balance by $23.3 million for the projected test year. *Id*., pp. 33-34.

Consumers responds to the Attorney General's exceptions by contending that the ALJ's reasoning was well-founded and consistent with the Commission's policy for the appropriate amount of cash needed to maintain the company's liquidity and protect against capital market risks. Consumers repeats the support it provided on the record in favor of its proposed cash balance and contended that the Attorney General did not provide support for her claim that the lower amount is a more representative average cash balance for the projected test year. Consumers' replies to exceptions, pp. 53-54. As to the Attorney General's claim that a six-month average of Consumers' cash balance is appropriate as opposed to the ALJ's recommended 13-month average cash balance, Consumers states that this is incorrect; the company holds more cash in the spring and summer months and relies on short-term borrowing in the fall and winter months. *Id*., p. 54.

Consumers continues that the Attorney General's reduced cash balance ignores Consumers' testimony that in Spring 2023, the company had not yet restored its normal level of cash balances from the lower balance caused by natural gas price spikes in 2022. As to the Attorney General's argument in exceptions that prior use of a 13-month average does not justify the use of one in this case, Consumers argues that the Attorney General did not contest the Commission's long-standing policy with new evidence or a change in circumstances. *Id*., p. 56 (relying on *Pennwalt Corp v Pub Serv Com'n*, 166 Mich App 1, 9; 420 NW2d 156 (1988)). Lastly, addressing the Attorney General's opposition to the 1% of revenue benchmark, the company argues that the ALJ's finding that such a method was a reasonable means of determining an appropriate cash balance was consistent with the Commission's past decision and the Attorney General's position in a previous case where the Attorney General advocated for a 1% of revenue benchmark. Consumers' replies to exceptions, p. 57 (citing the September 26, 2019 order in Case No. U-20322, p. 52).[11]

[11] In its replies to exceptions, Consumers cites to Case No. U-20332; however, the correct case number is Case No. U-20322.

Finding the ALJ's recommendation to be well-reasoned and supported by the record, the Commission adopts the PFD. The Commission agrees that Consumers' 13-month average method is consistent with past approvals of methods to determine cash balances and is reasonable given the abnormal disruption in the company's typical cash balance. *See*, 4 Tr 627-628, 795-800. However, the Commission notes that while it finds that the circumstances described by Consumers in this case constitute an abnormal disruption, the Commission will continue to evaluate the facts and circumstances of each rate case to determine whether deviation from the historical period is appropriate.

C. Total Rate Base

Based on her recommendations regarding the items comprising rate base in this case, the ALJ recommended that the Commission adopt a total rate base amount of $13,686,085,000. PFD, p. 216; Attachment B to the PFD.

Consistent with the decisions described *supra*, the Commission recommends a total jurisdictional rate base of $13,669,075,000.

V. CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure

Consumers proposed an equity ratio of 51.5%. 4 Tr 694; *see also*, Exhibit A-14, Schedule D-1. The Staff, however, recommended the adoption of a common equity ratio of 50.02%. 5 Tr 3623; Exhibit S-4, Schedule D-1. The Attorney General set forth a 50/50 debt to equity structure citing, in part, the Commission's preference for a balanced capital structure. 4 Tr 3000-3001; Exhibit AG-1.17.

The ALJ thoroughly reviewed the positions of the parties at pages 217 through 250 of the PFD, which will not be repeated here. After her review, the ALJ held that:

> Consumers has not established that its request for a capital structure with an equity ratio of 51.5% is reasonable and consistent with prior Commission orders; the company has not shown that a continuing deviation from a balanced 50/50 capital structure is appropriate, and has not established that a reduced equity ratio of 50% will jeopardize Consumers' credit or its ability to attract capital.

PFD, p. 250. More specifically, the ALJ quoted the Commission's February 28, 2017 order in Case No. U-17990 (February 28 order) and the July 31, 2017 order in Case No. U-18124 (July 31 order) to reiterate the importance of maintaining a capital structure that is reasonably balanced between debt and equity. The ALJ further agreed that increasing the equity ratio above the last Commission authorized equity ratio as proposed by the company was a move in the wrong direction. PFD, p. 252.

The ALJ also reiterated that the Commission has previously concluded that the federal Tax Cuts and Jobs Act of 2017 has not affected the appropriateness of a balanced capital structure. PFD, p. 252 (citing September 26, 2019 order in Case No. U-20322 (September 26 order), pp. 55, 62, and December 17, 2020 order in Case No. U-20697, pp. 153-154, 156). In response to the company's arguments surrounding its credit rating, the ALJ concluded that "a review of the recent credit reports indicates that Consumers has a good credit rating which should not change with a reasonable lowering of the equity ratio and ROE." PFD, p. 254. The ALJ also noted that the Commission has previously acknowledged that Consumers' prior credit rating was overstated and remained healthy even after a downgrade. PFD, pp. 254-255 (citing December 22 order, p. 220).

The ALJ also found that:

> [t]he factors that the Commission considers in assessing a reasonable equity ratio and the factors that the Commission considers in assessing a reasonable ROE are not the same. In addition, the Commission has not agreed to the linkage between equity balance and ROE that Consumers proposes. Indeed, the only apparent linkage between equity balance and ROE seems to be that these are both inputs, included among other inputs, in determining a company's FFO [funds from operations]/debt ratio by the credit rating agencies.

> Moreover, Consumers' assertion that the linkage between equity ratio and ROE requires a balance between equity ratio and ROE is fundamentally at odds with the calculation of the FFO/debt ratio and the purpose for which the ratio is considered. Consumers' purported linkage of equity ratio and ROE serves to elevate the importance of these two inputs over other inputs to the calculation, such as debt. Certainly, as recognized by the other parties and the credit rating agencies, if Consumers' debt balance was to change, its FFO/Debt ratio could also change with or without a material change to either Consumers' equity ratio and/or its ROE. Similarly, Consumers' proposed linkage also tends to elevate the significance of the FFO/debt credit metric over other credit metrics. Thus, [this ALJ] concludes that, while important, the FFO/debt ratio is not necessarily a driver of the rating agencies' overall credit rating for a utility, such that any reduction in Consumers' FFO/debt ratio will not necessarily adversely affect Consumers' credit rating.

PFD, pp. 256-257.

The ALJ rejected Consumers' argument that items such as securitization debt, short-term borrowings, and leases should be considered when determining the company's authorized capital structure as pertaining to Consumers' credit rating. She noted that similar arguments have previously been rejected by the Commission. PFD, p. 258 (citing December 22 order. p. 204). The ALJ also concluded that Consumers abandoned its own argument that the equity ratios of proxy groups are significantly higher than the equity ratio it seeks in the instant case because the company "proposes a common equity balance well below the peer company's equity ratio averages that it references." PFD, p. 259.

In finding that Consumers failed to establish the reasonableness of its proposed equity ratio of 51.50%, the ALJ concluded that the 50% equity ratio recommended by the Staff, the Attorney General, and ABATE is reasonable, supported by the record evidence, and consistent with prior Commission orders. *Id*. The ALJ further held that "a proposed reduction to the equity balance without a corresponding increase to the projected long-term debt balance inappropriately and unreasonably lowers Consumers' total capitalization." *Id*., p. 260. Therefore, the ALJ recommended the adoption of the Attorney General's long-term debt balance. *Id*., pp. 259-260 (citing 4 Tr 3000; Exhibit AG-1.17). Noting agreement between Consumers, the Staff, and the Attorney General regarding short-term debt, deferred federal income taxes (FIT), and the federal Job Development Investment Tax Credit (JDITC), the ALJ recommended adoption of Consumers' balances. PFD, p. 260 (citing Exhibit A-24, Schedule D-1 and D-1a; Exhibit S-4, Schedule D-1; Exhibit AG-1.17; and Consumers' initial brief, pp. 227-228).

Consumers takes exception to the ALJ's recommendations. Specifically, Consumers argues that the recommendation to utilize a 50% equity ratio "will contribute to further deterioration of the Company's credit metrics, rather than maintaining the Company's credit, which is one of the proper constitutional goals that should be driving the decision." Consumers' exceptions, pp. 72-73. Consumers further avers that the ALJ selectively applied prior Commission orders when determining the appropriate capital structure. While acknowledging the Commission's "recent policy preference that the Company maintain a capital structure balanced approximately evenly between debt and equity," the company states that the Commission has also reiterated that some flexibility is necessary. *Id*., pp. 73-74 (citing December 22 order, p. 200, and September 26 order, p. 61). Consumers further emphasizes that "[p]revious Commission orders do not constitute binding precedent and do not have the preclusive effect of the legal doctrines of *res judicata* or collateral estoppel" and that the appropriate equity ratio should be based upon the facts and evidence in the instant record. Consumers' exceptions, p. 74. To that end, Consumers avers that it has demonstrated its proposed equity ratio is supported on this record, that "[u]nquestioned and unyielding adherence to the trajectory set by three different Commissioners seven years ago without regard to the change in circumstances is not sound policy anymore" and that even those orders included language "that made it clear that the course could correct and adapt if circumstances changed, and that commitment has been reaffirmed in subsequent Commission decisions as well." *Id.*, p. 76.

Consumers reiterates its record testimony regarding credit metrics and alleges that the ALJ improperly dismissed the company's "testimony regarding the importance and the prudence of managing the Company's finances with a reasonable cushion above downgrade thresholds." *Id.*, p. 77 (citing PFD, p. 253). The company further contends that the ALJ selectively quoted a recent Standard and Poor's (S&P) credit report and failed to acknowledge the cautionary statements in the same credit report. Consumers' exceptions, pp. 77-78. Similarly, the company points to the ALJ's reference to a 2023 credit opinion from Moody's Investors Service (Moody's) which she contrasted with a 2021 Moody's report which specifically identified the pandemic, increased gas prices, and the banking crisis as risks to argue that "those specific risks were emergent and unprecedented risks in 2021, but they are no longer so in 2023." *Id.*, p. 78. Overall, the company argues that the rejection of its concerns regarding a degradation in credit metrics is not supported by the record.

Consumers further argues that the ALJ inappropriately minimized the concerns regarding potential credit metrics downgrades and incorrectly adopted the Staff's and the Attorney General's assertions that the Moody's downgrade was appropriate given it was "out of line" with other credit rating agencies. The company avers from precedent that "a constitutionally sufficient rate of return require[s] the regulator to pursue a path to 'maintain' the utility's credit, not deteriorate it" and as such, its concerns regarding a potential downgrade should be considered. *Id.*, p. 80. The company again claims the ALJ's reliance upon credit reports was selective and failed to acknowledge the warnings "that the Company's credit health is heading in the wrong direction." *Id.*

Consumers further points to its actual equity ratio versus the company's authorized equity ratio, noting that "it is clear that the Company has maintained a significantly higher equity ratio in practice than has been recognized in rates." *Id*., p. 81. Consumers states that it has "made the choice to absorb further dilution in earnings, all else being equal, in order to protect the Company's credit quality in the face of prior Commission orders that failed to do so," but notes that it "may not be able to continue that practice indefinitely, and it is fundamentally unjust to ask the Company to do so." *Id*. The company, therefore, argues that some language in credit reports noting stable credit health do not assume a further reduction in company's authorized equity ratio and ROE.

Reiterating its record testimony and evidence, the company argues that the ALJ's finding that the link between the equity ratio and ROE is at odds with the FFO/debt ratio is not supported on the record. *Id*., pp. 82-84. Consumers clarifies its position stating that:

> [i]t is not that ROE and equity ratio are "elevated" in importance compared to debt in the equation. It is that the Commission has to recognize the effect of reducing ROE and equity ratio on the equation. If the combination of ROE and equity ratio decline, without a corresponding reduction in debt, the ratio will become more and more unfavorable from the viewpoint of the credit analysts and the Company's credit rating will suffer. So, it is clear that debt is equally important to that equation. The problem is that no one in this case is proposing to reduce the Company's debt in order to keep the FFO-to-Debt ratio healthy. As a matter of fact, the [ALJ's] proposal is to simultaneously increase the amount of debt in the capital structure, which only further skews the FFO-to-Debt ratio into unfavorable territory.

Consumers' exceptions, pp. 84-85 (citing PFD, p. 260).

Consumers acknowledges that the ALJ properly recognized that the company's equity balance cannot be artificially reduced but claims that the ALJ "and the opposing parties in this case want to arbitrarily start in the middle of the appropriate decision process and ignore the information needed to do it right because they all seek to minimize the equity ratio at all costs." Consumers' exceptions, p. 85. The company continues, arguing that the FFO/debt ratio is not the only factor but that it is a factor upon which agencies place greater emphasis. Therefore, Consumers avers that the Commission should reject the ALJ's claims because they minimize the importance of the FFO/debt ratio. The company states that adoption of the ALJ's proposed equity ratio and ROE "will have a negative impact on the Company's credit metrics, which have already been weakened as a result of external economic conditions and several cycles of reductions to the Company's ratemaking equity ratio and ROE, and it will increase the risk of a credit downgrade." *Id*., p. 86.

The company also takes exception to the rejection of its adjusted equity ratio analysis. Consumers avers that the ALJ misapplied the Commission's rejection of its adjusted equity ratio analysis in Case No. U-20963. The company notes that it is proposing a lower equity ratio in this case as compared to Case No. U-20963 and that its credit metrics have deteriorated further since the final order was issued in that case. Citing the Staff's testimony from Case No. U-21090, Consumers argues that it was improper and imprecise to reject information that was accurate and relevant. Therefore, the Company states that the Commission should consider its adjusted equity ratio analysis. Consumers' exceptions, pp. 86-87.

Finally, Consumers disputes the ALJ's finding that the company abandoned the argument that the equity ratios of proxy groups are significantly higher than the equity ratio requested in this case. To the contrary, Consumers asserts that it provided evidence demonstrating that "an equity ratio set too low in this case would be out of line with that of comparable utilities and that the market is currently supporting equity ratios meaningfully higher than 50%." *Id*., p. 91. Give the above, Consumers argues that "[t]he Commission should reject the [ALJ's] recommendation and adopt Consumers Energy's recommended equity balance and the resulting equity ratio of 51.50%, which was developed using an analysis of the actual equity infusions and retained earnings the Company plans to incorporate through the test year in this case." *Id*., p. 93.

The Staff replies that the ALJ properly recommended the adoption of a 50% equity-based capital structure in line with the Staff's, the Attorney General's, and ABATE's position. The Staff states that the company's arguments regarding the ALJ's application of prior Commission orders is unpersuasive. The Staff further contends that "the current Commission asserts that a capital structure equally balanced between debt and equity is most preferrable" and in the "current challenging economic environment, customer affordability is paramount and a capital structure equally balanced between debt and equity will go a long way in ensuring fairness to the Company and its ratepayers." Staff's replies to exceptions, p. 6. The Staff avers that despite Consumers' claims, a balanced capital structure will not lead to a credit downgrade and does not represent a degradation to the credit metrics. Further, the Staff states that "[t]he ALJ's in-depth and substantial analysis took into account the copious evidence presented by each party with respect to either supporting the elevated ratemaking equity layer recommend by the Company or reducing the level to equilibrium, which comports with the Commission's stated objective." *Id*., p. 7.

Regarding the FFO/debt ratio, the Staff posits that it and other intervenors calculated and forecasted the ratio for the upcoming years and found it was well above the downgrade threshold with a balanced structure. *Id*., p. 8 (citing 5 Tr 3620-3621; 4 Tr 3007-3011). The Staff reiterates that the Commission has previously rejected Consumers' adjusted equity analysis and that the Commission orders "have been steady in their desire for the Company to rebalance its capital structure to 50/50." Staff's replies to exceptions, p. 8. The Staff also replies that it "performed an analysis of its proxy group's authorized equity ratios, not a peer utility equity ratio comparison that the Company performed, which included several companies not in the Company's proxy group and excluded several companies in the Company's proxy group." *Id*. Therefore, the Staff contends the ALJ properly rejected the company's argument.

In reply, the Attorney General disputes the company's claim that the ALJ improperly and selectively applied prior Commission decisions. Specifically, she states that it was inappropriate for the company's equity ratio to become so unbalanced and that the "Commission has been slowly and methodically adjusting the Company's equity ratio in the direction of a balanced debt-equity ratio." Attorney General's replies to exceptions, p. 62. The Attorney General further states that the PFD contains extensive analysis and Consumers' claim that the ALJ improperly dismissed its arguments is inaccurate. The Attorney General specifically points to the FFO/debt analysis and states that the ALJ's analysis of the company's claims was not a mere dismissal.

The Attorney General continues, arguing that Consumers has not demonstrated that it requires an equity ratio of 51.50% to maintain its credit metrics and that "[t]he ratings agencies report that the Company's performance in recent years have been above their respective thresholds for downgrades." *Id*., p. 63 (citing Exhibit AG-1.26). On the other hand, the Attorney General avers that the record evidence, including credit agency reports, supports a reasonable equity ratio of 50% as set forth by the Attorney General. The Attorney General also contends that the ALJ properly disregarded the company's adjusted equity ratio analysis, which has previously been rejected by the Commission. Overall, the Attorney General states that the Commission should not be swayed away from moving towards a balanced capital structure. Attorney General's replies to exceptions, p. 65.

ABATE replies to Consumers' exceptions, arguing that the Commission should adopt the ALJ's recommendation on the appropriate equity ratio because the company failed to support its request for a higher equity ratio. ABATE's replies to exceptions, p. 7. ABATE continues, noting that the company has favorable credit ratings with a stable outlook and the "claimed need for a higher equity ratio is therefore inadequately supported and should be rejected." *Id*., p. 8. ABATE argues that the ALJ properly rejected the company's adjusted equity ratio analysis and that Consumers' claims regarding average equity ratios of proxy utilities are misplaced. *Id*., pp. 8-9.

The Commission finds that the record supports the adoption of a balanced capital structure. The Commission is unpersuaded by the company's arguments that the adoption of a balanced capital structure will degrade Consumers' credit metrics. The adoption of a balanced capital structure results in a modest reduction in the authorized equity layer, given Consumers' agreement to a 50.75% equity layer in Case No. U-21224. *See*, January 19 order, Exhibit A, p. 4. The Commission also finds that the ALJ did not ignore or improperly reject the company's evidence as claimed by Consumers in exceptions. Rather, the ALJ set forth a detailed and well-reasoned evaluation of the parties' positions. *See*, PFD, pp. 217-261.

Notwithstanding the above, the Commission finds that the most reasonable and prudent approach to achieving this goal was set forth by the Staff. Therefore, the Commission finds that a common equity layer of $10.880 billion should be adopted, which equates to a 50.02% equity ratio in the permanent capital structure. *See*, 5 Tr 3623; Exhibit S-4, Schedule D-1, line 3. This equity balance is a slight reduction to the 50.75% equity layer agreed to by the parties in Case No. U-21224, which is consistent with prior Commission directives to gradually achieve a balanced capital structure. *See*, 5 Tr 3616, 3624–3626; *see also*, January 19 order, February 28 order, July 31 order, and December 22 order).

B. Cost Rates

1. Return on Common Equity

The criteria for establishing a fair ROE for public utilities is rooted in the language of the landmark United States Supreme Court cases *Bluefield Waterworks & Improvement Co v Pub Serv Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923) (*Bluefield*) and *Fed Power Comm v Hope Natural Gas Co,* 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944) (*Hope*). The Supreme Court has made clear that, in establishing a fair ROE, consideration should be given to both a utility's investors and its customers. 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." *Meridian Twp 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 ROE for Consumers.

Consumers, the Staff, the Attorney General, ABATE, and MNSC offered analyses of the appropriate ROE. The ALJ provided a detailed summary of the parties' analyses, arguments, and briefing in the PFD. *See*, PFD, pp. 263-331.

Consumers requested an ROE of 10.25% relying upon: (1) the Capital Asset Pricing Model (CAPM) and an empirical approximation to the CAPM (ECAPM), (2) a Projected Risk Premium analysis, (3) a Discounted Cash Flow (DCF) analysis, and (4) a Comparable Earnings analysis. 4 Tr 2358-2359, 2363-2364. The company averred that its proposal represents a reasonable ROE that will not place an undue burden on ratepayers. *See*, 4 Tr 2360-2362.

The Staff recommended the adoption of a 9.8% ROE as the midpoint of its range (9.30% - 10.30%) based upon the DCF, CAPM, Risk Premium and Bond Rate model, and further examination of ROE authorizations from regulatory commissions across the nation. 5 Tr 3616.

The Staff further contended that its ROE recommendation is at the higher end of a fair return and should be adopted as reasonable. 5 Tr 3619.

The Attorney General utilized the DCF, CAPM, and utility risk premium approaches to recommend an ROE of 9.8%. 4 Tr 3022. The Attorney General started with 37 electric utilities in the proxy group and narrowed down the group to 13 utilities which she contended are comparable to Consumers. 4 Tr 3023. The Attorney General noted that the use of a short time period to calculate the market risk premium was inappropriate because it "does not take into consideration the stock market returns and utility bond yields during both expansion and contractions in the economy." 4 Tr 3033. Citing Exhibit AG-1.22, the Attorney General compared approved ROEs for several utilities, and noted that the currently approved 9.9% ROE for Consumers is higher than others authorized around the country. 4 Tr 3038-3039; Exhibit AG-1.22. The Attorney General also averred that a reduction in ROE would be unlikely to affect the company's ability to access the capital markets as Consumers contends. *See*, 4 Tr 3043.

ABATE recommended adoption of an ROE no greater than 9.5%, the midpoint of its range of 9.05% to 9.95%, whereas MNSC concluded that an authorized ROE of 9.33% was just and reasonable. *See*, 4 Tr 2854, 2677-2682. While other intervenors did not set forth specific ROE analyses, Walmart asserted that both Consumers' recommended ROE and its Commission-authorized ROE were excessive. 5 Tr 3555-3556. UCC argued that any increases to Consumers' ROE should be limited until Consumers' performance improves, and the CEOs claimed that the Commission should approve a reduced ROE and at a minimum, not approve an increase of ROE. 5 Tr 3411; 4 Tr 3256.

As noted above, the ALJ carefully reviewed and further analyzed the positions of the parties at pages 263 through 372 of the PFD, which will not be reviewed extensively here. The ALJ concluded that the ROE recommendations of the Staff, the Attorney General, ABATE, and MNSC were reasonable and supported on this record. She further found "that all of the ROEs recommended by Staff and the intervenors each are more than sufficient for Consumers to maintain its credit and attract capital, and that Consumers' recommended ROE and current ROE are unnecessary to do so." PFD, p. 373. Therefore, the ALJ recommended that the Commission approve an ROE of 9.80% in this case.

In reaching her conclusion, the ALJ agreed with intervenors that Consumers' "market risk premium input is not appropriate" and "serves to unfairly inflate [its] CAPM result" and that the company's 12.89% result "is well outside of the range of the other parties' CAPM results (9.01% - 10.54%)." PFD, p. 335. The ALJ found the Staff's and the Attorney General's use of data covering "long time periods, as opposed to Consumers' use of short time periods which coincide with economic expansion" to be more reasonable. *Id*., p. 336. The ALJ also noted that Consumers did not justify its use of the ECAP model, which is considered an obscure variant of the CAPM model. *Id*., pp. 337-338. In rejecting the company's comparable earnings model, the ALJ found that FERC's and the parties' reasonings were persuasive. *Id*., p. 341.

With respect to the DCF methodology, the ALJ noted the dispute regarding the growth rate input before finding that "Consumers' short-term 3-year growth rate is misleading as a short-term rate cannot exceed the anticipated growth rate for the economy as asserted." *Id*., pp. 342-344. Notwithstanding this, the ALJ stated that:

> rather than reject Consumers' DCF model results, this [ALJ] shall consider an adjusted Consumers' DCF analysis result using [Consumers witness] Mr. Wehner's DCF formula and inputs while weighting Mr. Wehner's analysts' dividends per share growth rate at 80% and while applying a 4.30% long-term growth rate – the long-term growth rate proposed by [ABATE witness] Mr. Walters, which is close to the long-term rate of 4.20% proposed by [MNSC witness] Mr. Bandyk – with a 20% weighting. This adjusted DCF analysis results in a 9.37% ROE estimate.

PFD, p. 345.

Similar to the company's CAPM model, the ALJ found "that Consumers' use of the short time period represents an unnecessary adjustment which unreasonably inflates the model[']s results." *Id*., p. 348. The ALJ further found that the company's justification for the use of a short period was not persuasive. *Id*., p. 350. She noted that the Commission has previously stated that a reasonable ROE is not an exact mathematic calculation and thus "differences regarding the appropriate use of other models and inputs need not be resolved in this case." PFD, p. 353.

In sum, the ALJ concluded that:

> the ROE recommended by ABATE (9.5%) matches the middle of the range supported by the averages of the accepted models employed by the parties and the average of recent state authorized ROEs, and that the recommended ROEs of Consumers' (10.25%), Staff (9.80%), the Attorney General (9.80%), and MNSC (9.93%) as well as Consumers' currently authorized ROE (9.90%) are well above such middle range and averages.

Id., p. 354. In addition, the ALJ found "that consideration of recently authorized ROEs, including those in the [S&P Global] RRA [Regulatory Research Associates] database, is appropriate" noting that "the average of recently authorized (2022-2023) ROEs from other states is 9.56%, with a range of 8.57% - 10.00%." *Id*., p. 357.

The ALJ stated "that regulated utilities are much less risky than other businesses" and that to reconcile the imbalance while adhering to precedent, "the ROE should be set closer to the lower end of the range of comparable, recently authorized ROEs from other states." *Id*., pp. 358-359. The ALJ also noted that the record demonstrates that Consumers has strong credit ratings and the company provided statements that the FFO/debt ratios are projected to remain above downgrade thresholds. *Id*., p. 363. The ALJ found that recent credit reports had not mentioned the "Covid-19 pandemic, increasing inflation, increasing interest rates, market volatility, or geopolitical disputes as potentially affecting Consumers' credit rating or projected financial performance" and, as such, found Consumers' assertions regarding unforeseen events to be unsupported. PFD, pp. 366-367.

In conclusion, the ALJ held that:

> the ROEs recommended by Staff, the Attorney General, ABATE, and MNSC each are reasonable, supported by the accepted evidence and commensurate with returns on investments having corresponding risks, albeit at rates above the returns currently garnered by companies in the general market, while the ROE recommended by Consumers are not. This [ALJ] also finds that the ROE recommended by ABATE (9.5%) best matches the middle of the range supported by the averages of the accepted models employed by the parties and the average of recent state authorized ROEs, and that the recommended ROE of Consumers' (10.25%) and Consumers' currently authorized ROE (9.90%) are well above such middle range and averages. This [ALJ] further finds that all of the ROEs recommended by Staff and the intervenors each are more than sufficient for Consumers to maintain its credit and attract capital, and that Consumers' recommended ROE and current ROE are unnecessary to do so. Accordingly, this [ALJ] recommends the Commission authorize an ROE of 9.80% for Consumers.

PFD, pp. 372-373.

In exceptions, Consumers avers that the ALJ's recommended ROE is inconsistent with regulatory precedent and would not amount to just and reasonable rates as required by law. *See*, Consumers' exceptions pp. 93-94. Consumers alleges that the ALJ misapplied the standards when considering MNSC's claims regarding average ratemaking ROEs for regulated electric and gas utilities being above average nationally. The company continues, arguing that the entire market over the past 30 years is not relevant to setting an appropriate ROE for Consumers. Thus, Consumers contends that the Commission should reject the premise that its ROE should be set lower than the average returns in the market as a whole. *Id*., p. 95 (citing PFD, p. 358).

Consumers also states that the ALJ inappropriately claims that the company, as a regulated utility, lacks risk. Consumers' exceptions, p. 97. The company reiterates that the ALJ utilized selective pieces of credit reports and ignored cautionary language in the same reports. Consumers also argues that the ALJ did not appropriately consider its testimony regarding unforeseen market events that are more than speculative. *Id*., pp. 98-100. The company alleges that the ALJ dismissed annual savings based upon a "faulty reading of the Company's exhibit" and that the evidence should not be dismissed. *Id*., p. 101.

Reviewing its record evidence and methodologies, the company claims that it is appropriate to review multiple methodologies along with professional judgment and that the ALJ's "analysis of the quantitative model results should be rejected because it fails to do that . . . ." *Id*., p. 102; *see also*, *id*., pp. 102-118. Consumers contends that the Commission should reject the ALJ's criticism of the company's use of data from limited time periods, because an "analyst should not use data from time periods that were unlike current conditions," and the ALJ's criticism that Consumers' results were outside the range of other parties' results. *Id*., pp. 103, 110. With respect to the latter, the company contends that the ALJ's analysis improperly applies the preponderance of the evidence standard. *Id*., p. 104. The company further alleges that its added methodologies should at least be considered as additional data points for consideration. *Id*., p. 106. In sum, the company avers that:

> [n]one of the models for estimating ROE, standing alone, are sufficient. They all have assumptions that may or may not be consistent with current conditions. They all have strengths and analytically sound underlying theories that other models may be missing. They also all have weaknesses that may render the results from a single model less reliable under certain conditions.

Id., p. 114.

With respect to the company's DCF model, Consumers contends that the Commission should not consider the ALJ's attempt to use a multi-stage DCF in recalculating the company's analysis "and instead rely on the Company's calculation in deciding the appropriate ROE in this case." *Id*., p. 117. The company takes exception to the ALJ's weighting of its comparable earnings model, noting that the Commission has previously recognized the use of this model. *Id*. With respect to national ROE trends, Consumers contends that minimal weight should be given to such data and that the Commission has previously declined to place significant weight on ROE determinations not based on the instant record. *Id*., pp. 119-122. Overall, Consumers argues that the PFD contains "numerous errors and is not consistent with the criteria for a constitutionally minimally sufficient ROE" and that the Commission should approve the company's proposed ROE and capital structure without modification. *Id*., pp. 122-123.

The Attorney General also takes exception on this issue. While the Attorney General does not dispute the ALJ's recommendation for an authorized ROE of 9.8%, she disputes the weight provided to the record evidence. Specifically, the Attorney General argues that no weight should be given to the comparable earnings analysis as it is contrary to the record in this case. Attorney General's exceptions, pp. 35-36. With respect to the risk premium methodologies, the Attorney General avers that there are different types of risk premium methodologies. Specifically, she contends that the utility risk premium method submitted by the Attorney General:

> is based on market returns of utility stocks and bonds by (1) projecting the cost of debt for the peer group and adding to this cost (2) the average return differential of utility common stocks over utility bonds. This is and should be an acceptable approach because it is based on investor decisions reflected in the equity and bond markets. As shown in this rate case in Exhibit AG-1.21, the Utility Risk Premium results in a reasonable cost of equity of 9.83%, which is in the middle of the range of the cost of equity derived from the other two methods, DCF and CAPM (see Exhibit AG-1.18).

Attorney General's exceptions, p. 37.

UCC also excepts, noting agreement with the ALJ's rejection of the company's proposed ROE but asserts that the ALJ's "reasoning provides support for the Commission to approve an ROE lower than the [ALJ's] ultimate recommendation of 9.8%." UCC's exceptions, p. 2.

Consumers replies to the Attorney General's exceptions stating that the company partially agrees with the Attorney General that:

> the difference between FERC's Risk Premium approach and the Risk Premium approach used by the Attorney General is a valid and meaningful distinction. However, it is important for the Commission to recognize that Consumers Energy's Risk Premium approach is also based on investor decisions reflected in the equity and bond markets. The Company's approach and the Attorney General's approach are like one another in that important respect. Therefore, neither the Attorney General's Risk Premium Model nor the Company's Risk Premium Model in this case suffer from the circularity problem of FERC's Risk Premium Model.

Consumers' replies to exceptions, pp. 58-59. Consumers continues, arguing that the company's Risk Premium Model differs from the Attorney General's in that Consumers "has used market data that reflects current economic conditions to calculate its risk premium factor, whereas the Attorney General used all available historical market data to calculate her risk premium factor without regard to whether that data was taken from historical periods that do not reflect current market conditions." *Id*., p. 59.

Consumers also responds to the Attorney General's claims regarding the company's comparable earnings methodology, arguing that there is no basis to disregard this methodology that has been given weight and considered by the Commission in prior cases. *Id*., pp. 59-60 (citing 4 Tr 2448-2449). Moreover, the company alleges that considering multiple models is appropriate and the comparable earnings methodology provides an additional data point for the Commission to consider and upon which it can place the appropriate weight. Consumers' replies to exceptions, p. 60.

Responding to UCC, Consumers argues that the ALJ "failed to understand the assumptions built into the quantitative models used to estimate ROE and inappropriately rejected all of the Company's adjustments to the model inputs that correct for model assumptions that do not match current market conditions." *Id*., p. 61 (citing Consumers' exceptions, pp. 101-108). The company disputes UCC's recommendation to look at the national trends over the last three years because it is "backward-looking and tells the Commission nothing about what ROEs for a comparable company might be expected to be in the test year of this case." Consumers' replies to exceptions, p. 61. In conclusion, Consumers argues that UCC failed to provide a quantitative analysis and only indicates its desire for the Commission to set the lowest ROE possible. *Id*., p. 62.

In reply, the Staff notes that the company's exceptions are unpersuasive and should be rejected. The Staff asserts that it was reasonable for the ALJ to rely on the Staff's and the intervenors' ROE results and apply more scrutiny to Consumers' analysis because it was an outlier by comparison. *See*, Staff's replies to exceptions, pp. 11-12. The Staff further disputes Consumers' claims regarding the focus on the overall rate of return noting that it "is simply a mathematical combination of all the inputs used that make up the ratemaking capital structure." *Id*., p. 12.

The Attorney General also replies that the low risk profile of a utility does not justify the high ROE sought by Consumers. Specifically, the Attorney General states that "utilities face a smaller degree of risk compared to most of other businesses due to the regulatory scheme which provides for rate increases if reasonable and prudent and authorized rates of return. Therefore, a utility's return should be lower than other riskier businesses." Attorney General's replies to exceptions, p. 67. The Attorney General continues, arguing that the company does not need a 10.25% ROE because of the possibility of unforeseen circumstances and the impacts of COVID-19 have already been considered by investors. *Id*., p. 68. In addition, the Attorney General contends that the stock market has been historically volatile and should not be a concern in setting a fair ROE in this case. Moreover, the Attorney General avers that risk and volatility are not the same thing and should not be confused and that "utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market." *Id*., pp. 68-69 (citing Attorney General's initial brief, p. 134). In sum, the Attorney General cites to her briefs and concludes that Consumers "should not receive a ROE greater than 9.8%." Attorney General's replies to exceptions, p. 70.

ABATE replies that the company's requested ROE is excessive and that the company's objections to the PFD are flawed. Responding to Consumers' claims regarding unforeseeable events, ABATE states that "[t]he bounds of the hypothetical is not a basis upon which the Commission can issue a decision which must be authorized by law and supported by competent, material, and substantial evidence on the whole record, particularly in the context of deviating from ROE trends evidenced across the country." ABATE's replies to exceptions, pp. 9-10. ABATE continues, noting that the company's objections to the ALJ's treatment of the quantitative analyses include misstatements and should be given no weight. *Id*., pp. 10-11. ABATE reiterates that Consumers' proposed ROE "is excessive and does not reflect Consumers' risk or cost of capital." *Id*., p. 11. Therefore, ABATE concludes that the Commission should adopt the ALJ's recommendation to adopt an ROE of no greater than 9.8%.

MNSC also responds that the ALJ properly considered the full record and asserts that the Commission should reject the company's "attempt to narrow the record to only the evidence that supports its preferred outcome." MNSC's replies to exceptions, p. 5. MNSC also argues that the ALJ did not misapply the legal standards and that the ROE should reflect the relatively low risk nature of regulated utilities; otherwise, "the balance of investor and consumer interests would be skewed in favor of the investor." *Id*. MNSC emphasizes that the Commission has broad discretion to weigh and consider all factors including geographic proximity of proxy companies. Further, MNSC states that Consumers has not demonstrated it would be unable to obtain capital if the Commission authorizes an ROE below the company's recommended range, especially considering that regulated ROEs typically exceed market ROEs. *Id*., p. 7.

MNSC argues that the ALJ properly balanced the interests of the company's shareholders and customers and considered all evidence on the record. *See*, *id*., pp. 8-11. More specifically, MNSC states that the company's "exceptions present a one-sided review of only its own testimony and the PFD regarding five ROE models, with no mention or discussion of any other party witnesses, exhibits, or arguments related to the models." *Id*., p. 12. MNSC states that Consumers' exceptions should be rejected because the ALJ considered all record evidence and "did not recommend completely disregarding Consumers' testimony and analysis . . . ." *Id*., p. 14. In conclusion, MNSC argues that "Consumers' exceptions regarding the qualitative and quantitative ROE considerations and methodologies are incomplete, redundant, and provide no basis for the Commission to approve an ROE higher than recommended by the ALJ." *Id*., p. 16.

In reply, UCC states that the company's arguments regarding balancing the interests of the investors and the customers ignores Consumers' poor reliability. Moreover, UCC states that Consumers' arguments demonstrate that the company failed to account for customer interest in its proposed ROE. UCC highlights that the company has a fiduciary duty to act on behalf of investors rather than its customers, and, as such, "the only way to incentivize the Company to act in the interest of customers is to tie investor interests to customer interests." UCC's replies to exceptions, p. 5. Therefore, UCC encourages the Commission to properly balance customer interests in setting the ROE.

To start, the Commission finds that the ALJ appropriately considered the record evidence of each party. The Commission agrees with the ALJ's determination that Consumers' requested ROE of 10.25% is excessive and unsupported on this record. The Commission also agrees with the ALJ that, "the return to the utility's shareholders should be commensurate with returns on investments in other enterprises having 'corresponding risks.'" PFD, p. 358 (citing *Hope*, 320 US at 603; *Bluefield*, 262 US at 692, 693). In other words, in order to be found to be just and reasonable and meet the Supreme Court's requirement that a return appropriately balances the interests of utility shareholders with utility customers, consideration of the risk profile of the utility plays a central role. In cases where risk increases, a higher return is warranted. Conversely, where risk has been reduced, the authorized return should reflect that as well. As discussed elsewhere in this order, the Commission is approving a number of elements in this case which provide greater regulatory certainty and therefore reduce the risk profile of the company. These include both the IRM and the extended distribution deferral mechanism, to name just two examples. Moreover, while not on the record in this case, the recent energy legislation signed by Governor Gretchen Whitmer on November 28, 2023, has been widely credited with providing greater long-term certainty around utility capital plans. These factors all contribute to an assessment of a utility's overall risk profile, above and beyond the risk profile for the utility sector as a whole, and how the utility's risk profile factors into an appropriate risk-adjusted ROE. The Commission will continue to evaluate the evidence on the specific risk profile of a particular utility, which should be reflected in the utility's authorized ROE in future rate cases, including consideration of both utility-specific measures related to risk management, how changes in the policy environment impact the overall risk profile, and other considerations raised by the utility and intervening parties.

Notwithstanding this, the Commission finds that based on the record evidence in this case a reduction in the ROE is unwarranted at this time. As the Commission has previously noted, a reasonable ROE must be based on record evidence in the case at hand. Additionally, given significant uncertainty around inflation and interest rates, the Commission finds that the most prudent course of action is to maintain the current ROE. The Commission again notes that it may revisit this determination in future cases as it gains greater insight into the issues currently affecting the financial markets and longer-term macro-economic trends and will continue to seek opportunities to better tie a utility's financial performance to the outcomes experienced by its customers through the ongoing Financial Incentives and Disincentives Workgroup. Therefore, the Commission finds that the record supports an ROE of 9.90%.

2. Long-Term Cost Debt Rate

Consumers projected a long-term debt cost rate of 4.14%. 4 Tr 727; Exhibit A-14, Schedule D-2. The Staff and the Attorney General also utilized the long-term debt cost rate of 4.14%. 5 Tr 3632; Exhibit S-4, Schedule D-1; 4 Tr 3020; Exhibit AG-1.17.

The ALJ noted that the long-term debt cost rate was undisputed and adopted the same. PFD, p. 373, Appendix D, line 7.

No exceptions were filed on this issue.

The Commission adopts the undisputed long-term debt cost rate of 4.14% as reasonable and prudent on this record.

3. Short-Term Cost Debt Rate

Consumers projected a short-term debt cost rate of 4.79%. 4 Tr 732; Exhibit A-14, Schedule D-3. The Staff and the Attorney General again utilized Consumers' projection of 4.79%. 5 Tr 3632; Exhibit S-4, Schedule D-1; 4 Tr 3020; Exhibit AG-1.17.

Again, noting no dispute on this issue, the ALJ adopted Consumers' projected short-term debt cost rate of 4.79%. PFD, p. 373, Appendix D, line 5.

No exceptions were filed on this issue.

The Commission adopts the undisputed short-term debt cost rate of 4.79% as reasonable and prudent on this record.

4. Other Cost Rates

Consumers proposed a 4.50% cost rate for preferred stock and a blended cost rate for the long-term debt, preferred stock, and common equity components of JDITC. 4 Tr 734-735. The Staff noted agreement with the company's proposal. 5 Tr 3632. The Attorney General also utilized 4.50% cost rate for preferred stock and blended cost rates for JDITC, consistent with the company's proposal. 4 Tr 3020.

The ALJ noted the parties' agreement with respect to other cost rates and adopted the undisputed cost rates. PFD, p. 373, Appendix D.

No exceptions were filed on this issue.

The Commission again adopts the ALJ's well-reasoned recommendation to utilize the undisputed 4.50% cost rate for preferred stock and the blended cost rate for the components of the JDITC.

C. Overall Rate of Return

Consumers sought an overall rate of return of 6.11%, while the Staff recommended an overall return of 5.82%. 4 Tr 694; Exhibit A-14, Schedule D-1; Exhibit S-4, Schedule D-1. The Attorney General suggested an overall rate of return of 5.85%. Exhibit AG-1.17.

As noted by the ALJ, "[t]he differences are attributable to disagreements concerning Consumers' common equity balance, long-term debt, and proposed ROE." PFD, p. 217. Based upon her determinations of capital structure, debt costs, and ROE, the ALJ determined that the estimated overall weighted after-tax cost of capital should be 5.82%. PFD, p. 374, Appendix D, line 10.

Consumers takes exception to the overall rate of return recommended by the ALJ. Specifically, Consumers reiterates its position that investment is needed to address the distribution reliability challenges facing Consumers and its customers and argues that "[t]he authorized rate of return recommended in the PFD is not sufficiently supportive to attract the significant investment that will be needed." Consumers' exceptions, p. 68. After reviewing precedent, Consumers avers that "this is a time when the setting of 'just and reasonable' rates may require something more than setting a return at the bare bottom threshold of a constitutionally nonconfiscatory rate in order to attract the investment needed to improve on reliability outcomes." *Id*., p. 70.

Consumers continues, arguing that the ALJ unreasonably dismissed the validity of investor concerns raised by the company and that the ALJ's "failure to recognize that the ROE and the equity ratio used in the ratemaking process are essentially just inputs into a complex calculation that is designed to produce the value that actually matters for ratemaking purposes: the overall rate of return used to determine the final revenue requirement," was one of the most significant errors in the PFD. *Id*. The company asserts that regulatory-law precedent focuses on the overall rate of return in determining whether the rates are constitutionally sufficient. As such, Consumers avers that the ALJ's determination that the factors considered by the Commission in setting a reasonable equity ratio and a reasonable ROE are different is inconsistent with the vast body of regulatory caselaw. *Id*., p. 71 (citing PFD, p. 256). In sum, Consumers argues that the ALJ's recommendations regarding the capital structure and ROE should be treated with skepticism. Consumers contends that:

> [e]ven if the Commission concludes that the [ALJ's] recommendation meets the minimum requirements to withstand constitutional scrutiny, the Commission should nevertheless recognize that a higher return is required to satisfy the statutory standard of "just and reasonable" rates, so that there is sufficient support for the significant investments needed to improve upon the distribution system's reliability performance.

Consumers' exceptions, p. 72.

In reply, the Staff disputes the company's claims and argues that "the overall rate of return is simply a mathematical combination of all the inputs used that make up the ratemaking capital structure" and that the ROE and equity layers are the most important determinations in the case. Staff's replies to exceptions, p. 12. The Staff further opines that the ALJ's analysis was reasonable and prudent and should be adopted.

Given the above, the Commission adopts a 50.02% equity layer, a long-term debt cost rate of 4.14%, a short-term debt cost rate of 4.79%, an ROE of 9.90%, and an overall weighted cost of capital of 5.86%, as shown on the table below:

Description	Amount (000,000)	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	$ 10,833	40.95%	4.14%	1.70%
Preferred Stock	$ 37	0.14%	4.50%	0.01%
Common Equity	$ 10,880	41.13%	9.90%	4.07%
Short-Term Debt	$ 294	1.11%	4.79%	0.05%
Deferred FIT	$ 4,280	16.18%	0.00%	0.00%
JDITC Debt	$ 65	0.24%	4.14%	0.01%
JDITC Preferred Stock	$ 0	0.00%	4.50%	0.00%
JDITC Equity	$ 65	0.25%	9.90%	0.02%
Total	$ 26,454	100.00%		5.86%

VI. ADJUSTED NET OPERATING INCOME

Adjusted 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 374 through 443 of the PFD, the ALJ provided a thorough analysis of the issues and arguments regarding NOI. The issues raised therein are addressed below, *ad seriatim*.

A. Jurisdictional Revenue and Sales Forecast

1. Sales Forecast

Consumers presented a sales forecast of 36,415 gigawatt hours (GWh) of jurisdictional electric deliveries for the 2023 test year. 4 Tr 1032; Exhibit A-15, Schedule E-1. No party objected to Consumers' projections and as such, the ALJ adopted the sales forecast. The Commission finds the ALJ's recommendation well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's findings and conclusion on this issue.

2. Residential Income-Assistance Credit Projection

Consumers testified that its total projected electrical operating revenues including base tariff revenues, power supply cost recovery (PSCR) revenues, and miscellaneous revenues for the test year were $5.074 billion. Exhibit A-15, Schedule E-2. The company further testified that its base tariff revenues were reduced by the following credits: the Residential Senior Citizen (RSC) credit, the Residential Income-Assistance (RIA) credit, and the Low Income Assistance (LIA) credit. *Id*., *see* 4 Tr 1030. Consumers also relied upon its increase in credit disbursements from December 2021 to December 2022. Exhibit S-19.0, pp. 2-4.

The Staff argued that Consumers inappropriately applied RIA credits. The Staff explained that it did not support Consumers' consumer credit projections because "the [c]ompany's proposed 28%-61% increase in RIA enrollment is unreasonable and unsupported" when the full year's result showed only a 16% increase. 5 Tr 3935-3936. The Staff also highlighted that the company's RIA enrollment increase was due in part to "increased [COVID]-related federal funding and Michigan Department of Health and Human Services (MDHHS) LIHEAP allocations."[12] 5 Tr 3936.

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[12] "LIHEAP" is the Low Income Home Energy Assistance Program. *See*, Low Income Home Energy Assistance Program (LIHEAP) | The Administration for Children and Families (hhs.gov) (accessed February 26, 2024).

Furthermore, whereas there were four rounds of LIHEAP Direct Support payments in 2022, only one round of LIHEAP Direct Support payments was disbursed in 2023. 5 Tr 3936-3937, *see* Exhibit S-19.0, p. 3. Due to those facts, the Staff suggested use of historical three-year average annual RIA credit disbursements of 682,369, or 56,864 monthly RIA customers (amounting to $5,458,952). 5 Tr 3939-3940; 4 Tr 1045. This would decrease Consumers' annual projected RIA credit disbursement by $4,223,512. 5 Tr 3940.

Consumers objected to the Staff's position, arguing that it has "increased its vulnerable customer outreach efforts since 2022 and the [c]ompany is both continuing these efforts and expecting additional LIHEAP Direct Pay in the future. Also, as previously mentioned, the Company has been informed that [MDHHS] plans to provide Energy Direct Support in Q4 of 2023 and increased SER [State Emergency Relief] payments are expected." 4 Tr 1045; *see* Consumers' initial brief, p. 326. With the planned increase to reach vulnerable customers, Consumers projected increased enrollment numbers compared to the Staff's three-year average. 4 Tr 1045. Furthermore, Consumers argued that "there is no reason to think [that LIHEAP-eligible customers] would not re-enroll." Consumers' initial brief, p. 326.

The ALJ agreed with the Staff's position, finding that Consumers' application of data was less accurate given that the Staff used an entire year of RIA credits instead of comparing two months a year apart as Consumers did. PFD, p. 379. Additionally, the ALJ found credence in the Staff's argument that low-income customers do not necessarily re-enroll and that projections appeared to rely upon COVID-related disbursements and speculative outreach and funding opportunities. *Id*. The ALJ further agreed with the Staff that "without a tracker or deferred accounting, overprojection of RIA credits would result in Consumers retaining any overcollection." *Id*.

In its exceptions, Consumers insists that it considered its RIA customer enrollment trend over three years. Consumers' exceptions, p. 124. However, the company admits that customers receiving LIHEAP payments do not always re-enroll as RIA customers. *Id*., pp. 124-125. Despite such, Consumers states that in 2023, it "has seen a continued rise in RIA customers, which is expected to continue this year." *Id*., p. 125. Furthermore, Consumers states that approving a lower RIA offset than its current customer count "would disincentivize customer outreach," although it stated that it would ignore such disincentivization, thus rendering its own argument moot. *Id*., p. 126.

In their reply to exceptions, the Staff argues that the PFD's recommendation should be accepted. While the Staff reiterates several of its arguments, it also highlights that "MDHHS did not release a round of Energy Direct Support in Q4 of 2023" and because of such, Consumers' claims and its arguments on the issue should be disregarded. Staff's replies to exceptions, p. 14.

The Commission finds the Staff's position and the ALJ's recommendation well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's findings and conclusion on this issue.

3. Sales Forecasting and Rate Design Software Models

The Staff recommended that the Commission require Consumers to provide its forecasting and rate design models via "Microsoft Excel or the equivalent open-source software with all formulae and links intact." 5 Tr 3674. The Staff supported this request by explaining that auditors must be able to trace the origin of the data provided which cannot be done using Consumers' proprietary software. 5 Tr 3674.

Consumers stated that it plans to continue using its proprietary software but testified that it would be willing to "provide workpapers in future electric rate cases that would provide a more robust walk from the sales forecast to the rate design models." 4 Tr 1045.

While the ALJ did not make a definitive ruling on this matter, she suggested that "[i]t appears that Staff might agree with the company's proposal to continue using proprietary software for forecasting and rate design, provided the company include additional workpapers that show a clear crosswalk between the forecasted determinants and the data used in the company's rate design models." PFD, p. 380.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's findings and conclusion on this issue, and directs the company to provide workpapers and a more robust explanation on the derivation of inputs to rate design and other rate case models from the sales forecast.

B. Fuel, Purchased, and Interchange Power Expense

Consumers presented its projected fuel, purchased, and interchange power expense using the Aurora Production Costing program. 4 Tr 1038-1039, 2129-2152, Exhibits A-51 and A-146. No party objected to Consumers' projected fuel, purchased, and interchange power expenses. While the ALJ did not specifically adopt such, she acknowledged that no party contested the expense. PFD, p. 381. Furthermore, the ALJ noted that the Staff used Consumers' amounts as presented. *Id*.

The Commission finds the ALJ's inferred recommendation well-reasoned and supported by the record. Accordingly, the Commission adopts the company's projected fuel, purchased, and interchange power expenses as presented.

C. Other Operations and Maintenance Expense – Non-Power Supply Inflation Rate and Projection

Consumers provided evidence of non-power supply O&M expense of $654.954 million in 2022, with an adjusted amount of $677.293 million for the test year. Consumers' Exhibit Schedule C-5, p. 1, Schedule C-14, p. 1, 4 Tr 2808, *see* PFD, Appendix C. However, the Attorney General testified to various inflation rates that would equate to an adjustment of $2,296,000. 4 Tr 3055.

In response to the Attorney General, Consumers provided updated inflation rates and testified that inflation projections have increased based on the latest report issued by S&P Global Market Intelligence. 4 Tr 652. The Company also stated that the Attorney General's inflation rates do not align with S&P Global Market Intelligence's latest report. 4 Tr 652. Furthermore, the company provided a chart comparing inflation rates, asking that the Attorney General's inflation rates be rejected. 4 Tr 653.

Based on the information provided by the parties, and what she states is the "most current inflation forecasts in this record," the ALJ recommended rejecting the Attorney General's recommendations. PFD, p. 382.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's findings and conclusion on this issue.

Secondly, ABATE found Consumers' O&M expense to be "excessive relative to historical levels, and inconsistent with Consumers' ongoing efforts to minimize costs through productivity improvements and capital improvement projects." 4 Tr 2809. ABATE testified that Consumers' actual non-power supply O&M expense is unreasonable, being 15% higher than its historical average. 4 Tr 2810. Additionally, ABATE remarked that it did not feel that "Consumers has taken into account employee expense reductions that occur through attrition." 4 Tr 2809. Furthermore, ABATE testified that inflation is expected to decline through 2023 and 2024. 4 Tr 2817. ABATE also testified about the success of "Consumers' Energy Way" (CE Way), a "continuous improvement process used to control O&M levels less than the projected rate of inflation to offset expenses that grow at a rate greater than inflation," which has been in place for years, and that, in a past rate case, "Consumers explained that it had a stated goal of using CE Way to identify $35 million of O&M savings in 2021 for electric and gas operations, as well as a focus on achieving 5% year-over-year O&M savings going forward." 4 Tr 2811, 2813 (internal citation omitted). ABATE also expressed concerns about Consumers' inflation rate for employee labor, suggesting "a reduction of $11.152 million from Consumers' proposed test year level" for its non-power supply O&M expense projection. 4 Tr 2815.

In the PFD, the ALJ found that ABATE's analysis had some merit but "because the company's O&M projection changed significantly in rebuttal," and recognizing that the Commission prefers to look at individual O&M costs, she recommended rejecting ABATE's adjustment. PFD, p. 384.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's findings and conclusion on this issue.

1. Distribution Operations and Maintenance Expense – Electric Operations

    a. Staking and Service Calls Subprograms

Consumers proposed O&M expenses of $38.785 million related to its operations, maintenance, and metering program. Exhibit A-132, line 21. Within this program, Consumers outlined expenses for the test year in the staking and service calls subprograms totaling $5,282,088 and $4,518,000, respectively. 4 Tr 422-423, 430. According to Consumers, spending in the staking subprogram is primarily driven by stake volume requests, which Consumers anticipated would increase by 5% annually for contractor services. 4 Tr 423.

Consumers' staking subprogram also included cost increases of $673,258 associated with its electric-only staking program. 4 Tr 426. The increase included resources focused on locating only electric facilities for Consumers, which Consumers stated mitigates public safety, damage, timeliness, quality, and communications risks with excavators in some of the areas with the highest concentrations for staking requests, namely Kent, Kalamazoo, and Ingham counties. 4 Tr 426-427. The Staff recommended approval of Consumers' electric-only staking program with no adjustment and proposed that at the end of the three-year staking contract Consumers provide the Staff with a report containing, at a minimum: (1) the objectives of the program, (2) a list of itemized total costs broken down by year, and (3) a summary of findings and opportunities for improvement. 5 Tr 3974-3975. The Staff also outlined Consumers' reporting requirements for incidents involving damage to underground facilities and recommended additional system-level reporting on a quarterly basis and supplemental reporting to its quarterly electric damage reports. 5 Tr 3976-3978. Because Consumers did not file rebuttal on this topic or address it in briefing, the ALJ found that Consumers did not oppose these additional reporting requirements. *See,* PFD, p. 388.

For its service calls subprogram, Consumers projected that spending would be $287,000 more than what would be accounted for due to inflation alone as a result of the overall increase in New Business activity. 4 Tr 431.

The Attorney General disputed Consumers' anticipated staking volume increase, electric-only staking program, and spending above inflationary increases for service calls. With respect to the anticipated staking volume increase, the Attorney General provided testimony that Consumers' staking orders only increased at a 2% rate over the last three years, not 5%. 4 Tr 3058. Moreover, the Attorney General asserted that housing and permit starts, which are indicators of building activity that drive staking requests, had fallen in the first six months of 2023 and were likely to remain depressed into 2024. 4 Tr 3058. As a result, the Attorney General argued that it was unlikely that Consumers' anticipated 5% staking volume increase and additional expenses for increased service calls would materialize. 4 Tr 3058, 3060.

With respect to Consumers' electric-only staking program, the Attorney General provided testimony that the program was not adequately supported because Consumers merely provided testimony that it "hoped for" increases in timeliness, quality, and better communication with excavators because of the program. 4 Tr 3058. The Attorney General, therefore, called for a disallowance of the additional costs associated with the electric-only staking program. 4 Tr 3059. The Attorney General also recalculated staking expenses for the projected test year based on the percent changes in housing starts forecasted by IHS Markit forecasts, which resulted in a downward adjustment to O&M of $1,385,580. 4 Tr 3059; *see also*, Exhibit AG-1.38. The Attorney General also argued for a further downward adjustment to O&M of $287,000 for Consumers' forecasted expenses associated with service calls. 4 Tr 3060.

In response to the Attorney General, Consumers argued that it was on pace to meet or exceed its original new service connection projections for the bridge period through June 2023, and that LVD Lines New Business activity increased in 2023 compared with 2022. Consumers' initial brief, p. 330. Consumers, therefore, asserted that the Attorney General's reductions were unwarranted. *Id*.

The ALJ found that Consumers' electric-only staking program should be approved for the reasons stated in Consumers' initial brief. PFD, p. 389. The ALJ also found that the proposed amounts for the staking and service calls subprograms should be approved consistent with the acceptance of Consumers' projection for LVD Lines New Business. *Id*. Finally, the ALJ recommended that the Commission approve the Staff's recommendation for supplemental damage reporting, including the electric-only staking report to be filed at the end of the contract period. *Id*., p. 388.

In exceptions, the Attorney General reiterates her previous argument that because new building activity, housing starts, and other housing-related work are likely to decline in 2023 and into 2024, Consumers' projected staking request and service call increases are unsupported. Attorney General's exceptions, pp. 38-39. The Attorney General also argues that the electric-only staking program is not supported because there is nothing that prevents Consumers from addressing its concerns under its current staking program. *Id*., pp. 39-40.

In reply, Consumers responds by arguing that its new service connection forecast is consistent with up-to-date projections and in line with increased LVD Lines New Business since 2022 and further argues that the evidence in this matter supports the benefits of its electric-only staking program. Consumers' replies to exceptions, pp. 62-64.

The Commission has reviewed the record and the arguments by the parties and adopts the ALJ's recommendation to approve Consumers' projected expenses for the staking and service calls subprograms. The Commission finds that the increased spending in these subprograms is supported by Consumers' projections for LVD Lines New Business. The Commission further finds that the electric-only staking program, which was supported by the Staff, should be approved for the reasons stated in Consumers' initial brief. *See*, Consumers' initial brief, p. 330.

Additionally, the Commission finds that the parties did not oppose the Staff's recommendation for additional reporting and thus directs Consumers to provide the Staff with a report at the end of the three-year staking contract period containing, at a minimum: (1) the objectives of the program, (2) a list of itemized total costs broken down by year, and (3) a summary of findings and opportunities for improvement. The Commission also directs Consumers to supplement its quarterly electric damage reports to include system level details broken down by month throughout the year to include: (1) total tickets, (2) total miles of underground infrastructure, (3) damages per 1,000 tickets, (4) number of internal locating and marking employees, (5) number of external locating and marking employees, (6) internal employee details including average duration in current locating and marking position and average years of locating and marking experience, and (7) external employee details including average duration in current locating and marking position and average years of locating and marking experience. The Commission further directs Consumers to share billing amounts when a third party causes damages, costs to ratepayers when Consumers causes damages, and penalty amounts distributed in supplemental quarterly reports broken down by month. *See*, 5 Tr 3979.

b. High Voltage Distribution Lines Construction Workforce Subprogram

Consumers also proposed O&M expenses of $28.494 million related to its field operations program, including $607,000 associated with a new HVD lines construction workforce subprogram. Exhibit A-132, lines 31, 33. Consumers stated that the HVD lines construction workforce subprogram ensures that an appropriate in-house workforce will be available to service and maintain the company's HVD lines. 4 Tr 441. According to Consumers, because its external workforce could leave at any time when demand for services is higher elsewhere, an in-house workforce of 48 full-time employees is necessary to address anticipated increases in HVD lines workloads. 4 Tr 441.

The Attorney General questioned Consumers' proposed spending and noted two problems with the subprogram. First, the Attorney General provided testimony arguing that the new subprogram would eliminate existing costs associated with the outsourcing of Consumers' HVD lines work and that these cost savings have not been offset against Consumers' proposed expenses. 4 Tr 3066. Second, the Attorney General argued that the new subprogram was in the early exploratory stages and that Consumers has not provided evidence that a change from external contractors to in-house personnel was economically justified or in the best interest of customers. 4 Tr 3066. The Attorney General further observed that Consumers' implementation of this subprogram was a moving target because the subprogram had not been implemented in 2023 despite Consumers seeking expenses for such a subprogram in Case No. U-21224. 4 Tr 3066. Accordingly, the Attorney General recommended a disallowance of $607,000 for the subprogram. 4 Tr 3066-3067.

In response to the Attorney General's arguments, Consumers reiterated its view that it needed to develop an in-house HVD line workforce to mitigate the risk of an external workforce leaving. 4 Tr 491. Consumers also stated that an in-house workforce would benefit customers by ensuring that a skilled workforce is available to continue to make grid infrastructure improvements. 4 Tr 491; *see also*, Consumers' initial brief, p. 331.

The ALJ agreed with the Attorney General and found that the $607,000 expense for the HVD Lines Construction Workforce should be disallowed. PFD, p. 389. The ALJ noted that, while having some in-house HVD line personnel may be prudent, Consumers has not presented evidence that the subprogram was economically justified or that it would be implemented in the test year. *Id*.

In exceptions, Consumers reiterates its justification for expenses for the HVD Lines Construction Workforce as necessary to mitigate the risk of the external workforce leaving. Consumers' exceptions, p. 127.

In reply, the Attorney General reiterates that Consumers has not demonstrated that having an in-house workforce is in the best interests of ratepayers and that the lack of action after Consumers' initial proposal in 2022 is evidence that the need for such a workforce may be unwarranted. Attorney General's replies to exceptions, pp. 71-72.

The Commission has reviewed the record and the arguments by the parties and adopts the ALJ's disallowance of $607,000 for the HVD Lines Construction Workforce. The Commission agrees that, while having some in-house HVD line personnel may be prudent, Consumers has not presented evidence that the subprogram is economically justified or that it would be implemented in the test year. *Id*.

2. Forestry Operations and Maintenance Expense

Consumers proposed O&M expenses of $118,889,334 for line clearing for the test year, including $12,281,500 for HVD lines and $106,607,833 for LVD lines. Exhibit A-42, lines 2, 12, and 24. As part of these expenses, Consumers proposed increased spending to raise the miles of LVD circuits cleared each year until 1/7th of the total LVD mileage is cleared annually and to then maintain that level of clearing each year thereafter to bring the LVD system to a seven-year effective clearing cycle. 4 Tr 976. Consumers provided testimony that it used analytics from Machine Learning, satellite imagery analysis, and geographic information system (GIS) to optimize LVD line clearing cycles to account for total program costs for each voltage and measure the costs against reliability gains for customers served by that voltage. 4 Tr 977-980. According to Consumers, the seven-year effective clearing cycle was the most cost-beneficial approach to reducing tree-related outages on the LVD system at current conditions. 4 Tr 982; *see also*, Exhibit A-46. When the LVD system is fully on the seven-year effective clearing cycle, 14.4/24.9 kV circuits will be cleared on average between 4-6 years, 7.2/12.47 kV circuits will be cleared on average between 6-8 years, and 4.8/8.32 kV circuits will be cleared on average between 8-10 years. 4 Tr 979.

MNSC disputed Consumers' line clearing program and provided testimony that the seven-year effective clearing cycle length was too long. 4 Tr 2648. MNSC argued that peer utilities used shorter line clearing cycle lengths, with five years being common, and that Consumers' optimization of the effective clearing cycle for LVD lines did not account for customer costs of outages or service restoration costs. 4 Tr 2648. Accordingly, MNSC recommended that the Commission require Consumers to file a report within 90 days providing "a formal optimization analysis of line clearing cycles, or alternatively, risk-based line clearing using vegetation data, that accounts for the customer cost of customer outage minutes, the company's cost of service restoration, as well as the costs of line clearing" and that the report "should look with particularity to the customer costs and restoration costs associated with tree-caused outages and not at average values acrost all outages." 4 Tr 2650.

In response to MNSC's arguments, Consumers provided testimony to reiterate that the proposed seven-year effective clearing cycle was currently the most cost-beneficial approach to reduce tree-related outages for customers on its unique LVD system. 4 Tr 1012-1013. Consumers stated that although peer utilities use shorter cycle lengths, optimal cycle lengths will vary from utility to utility because of differences in miles of LVD lines and customers per mile of line.

4 Tr 1013. Consumers also disagreed with MNSC's recommendation that the company provide a formal optimization analysis because the seven-year effective clearing cycle was determined using metrics required by the Commission, including number of tree-related incidents and contractor clearing cost per mile, to optimize the customer reliability benefit relative to dollars spent. 4 Tr 1014. According to Consumers, if it was required to provide an optimization report incorporating customer costs and service restoration costs, Consumers would need to reprioritize resources that would otherwise be committed to its vegetation management plan that benefits system reliability. 4 Tr 1014.

The Staff supported Consumers' proposed O&M expenses for line clearing. 5 Tr 3954. The Staff, however, recommended that Consumers provide a description of how it audits line clearing work performed by contractors and company personnel, as well as audit results and any corrective actions taken by Consumers' management for the most recent calendar year. 5 Tr 3955. The Staff also recommended that Consumers provide an analysis of the feasibility of more aggressive line clearing in everything outside of the first zone[13] in its next rate case. 5 Tr 3955. According to the Staff, such an analysis would be a prudent step in decreasing tree-related wire downs and improving service reliability during storms. 5 Tr 3955. Additionally, the Staff recommended changing the filing date for Consumers' annual report on its line clearing program from December 15th to March 1st of the following year. 5 Tr 3956. Finally, the Staff recommended that Consumers develop a proposal for a residential service drop line clearing pilot but later withdrew this recommendation after Consumers noted that it already includes trimming residential service

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[13] Consumers' first zone work "clears the section of a circuit from the substation outward to logical load concentration points." 5 Tr 3955. Although these zones may have lower outage frequency than other areas, outages that do occur impact a higher number of customers. 4 Tr 970.

drops as part of its regular maintenance program. 5 Tr 3956; 4 Tr 1016; Staff's initial brief, p. 198.

The Staff also questioned Consumers' prioritization of tree trimming investments, observing that some areas in the company's service territory with low percentages of tree canopy had received higher tree trimming investments than similar areas. 5 Tr 3807-3809. Accordingly, although the Staff commended Consumers for its openness to share GIS data, the Staff nevertheless recommended that the Commission require Consumers to provide additional GIS data in future rate cases, including a map and underlying GIS data by census tract regarding areas where electric distribution investments impacting reliability, by program, have been made and where they are projected to be located in future rate cases. 5 Tr 3811.

In response to the Staff's recommendations, Consumers agreed to provide a description of how it audits scheduled O&M line clearing work performed in the field in its next rate case, including documentation regarding closeout and corrective actions undertaken by Consumers' management. 4 Tr 1015-1016. Consumers also agreed to change the filing date for its annual report on its line clearing program as recommended by the Staff. 4 Tr 1017. Consumers, however, disagreed with the Staff's recommendation that the company provide a feasibility study of more aggressive line clearing for everything outside of the first zone in its next rate case. 4 Tr 1016. Consumers asserted that the first order of priority should be clearing the backlog of circuits not cleared in many years and getting the LVD system on a seven-year effective clearing cycle. 4 Tr 1016. According to Consumers, foregoing a feasibility study would enable the company to utilize a more robust dataset of its LVD system's circuit performance on the seven-year effective clearing cycle plan that would not be skewed by circuits that are currently in backlog status. 4 Tr 1016.

With respect to the Staff's recommendation that Consumers provide additional GIS data, Consumers argued that it was not clear what problem would be solved by requiring production of the requested data. 4 Tr 484. Consumers contended that the company already provided significant data and maps in response to discovery in this case and that additional resources would be required to perform the analyses and results that the Staff recommended. 4 Tr 484. Consumers also alleged that most of its projects do not correspond neatly with census tracts, that it would be cumbersome to try to force them to align, and that producing such maps would be a time-intensive process and very burdensome. 4 Tr 485-486. Nevertheless, Consumers stated that it was willing to provide more detail in future rate cases and to continue collaborating with the Staff to provide information in response to specific inquiries. 4 Tr 485-486.

The ALJ found that Consumers' proposed O&M expenses for line clearing for the test year were unopposed and, therefore, should be approved. PFD, p. 399. The ALJ also found that Consumers and the Staff agreed on the company providing a report on auditing of its line clearing program in its next rate case, as well as a change of the filing date for Consumers' annual report on its line clearing program from December 15th to March 1st of the following year. *Id.* Accordingly, the ALJ recommend approval of these proposals. *Id*.

With respect to Consumers' seven-year effective clearing cycle for its LVD system, the ALJ agreed that MNSC's recommendation that Consumers evaluate shorter clearing cycles may have merit. *Id*., pp. 399-400. Similarly, the ALJ found that the Staff's suggestion that Consumers evaluate more aggressive clearing outside the first zone was a prudent first step. *Id*., p. 399. But the ALJ found that both recommendations were beyond the scope of the instant rate case and were more appropriately suited to be addressed in Consumers' distribution plan in Case No. U-20147. *Id*. The ALJ also found that there was no clear purpose for requiring Consumers to provide further

GIS data but nonetheless encouraged the parties to continue to collaborate with the company on ways to make available the locations of Consumers' infrastructure and the types of maps that can be produced. *Id*., p. 400.

In exceptions, Consumers agrees to analyze more aggressive line clearing outside the first zone so long as the company is not required to perform such an analysis until its next EDIIP filing is due. Consumers' exceptions, pp. 128-129. However, the Staff argues that waiting until Consumers' next EDIIP filing to analyze whether more aggressive line clearing outside the first zone is reasonable could cause unnecessary delay to potential reliability benefits. Staff's exceptions, p. 3.

In reply, Consumers confirms its agreement to perform the recommended analysis but again reiterates its desire to perform this analysis with the filing of its next EDIIP. Consumers' replies to exceptions, p. 66. Alternatively, Consumers requests the Commission to require Consumers and the Staff to seek agreement on the time such an analysis must be conducted. *Id*.

Additionally, in exceptions, Consumers disagrees that the company should be required to further evaluate shorter, fixed clearing cycles, arguing that such an evaluation has already been completed as part of its original optimization analysis. Consumers' exceptions, p. 129.

In reply, MNSC argues that Consumers failed to respond to the merits of MNSC's argument that the seven-year effective clearing cycle was barely more cost effective than clearing cycles approaching five years. MNSC's replies to exceptions, pp. 17-18. MNSC also argues that Consumers failed to address concerns regarding the proposed nine-year clearing cycle for 4.8 kV circuits, which comprise more than half of the company's LVD lines. *Id*., p. 19.

The Commission has reviewed the record and the arguments by the parties and finds that Consumers' proposed O&M expenses for line clearing for the test year were unopposed and should be approved. The Commission also finds that the parties agreed to the requirement that Consumers provide a description of how it audits line clearing work performed by contractors and company personnel, as well as audit results and any corrective actions taken by Consumers' management for the most recent calendar year, and that the parties agreed to change the filing date for Consumers' annual report on its line clearing program from December 15th to March 1st. Accordingly, the Commission adopts these recommendations. The Commission rejects the recommendation that Consumers develop a proposal for a residential service drop line clearing pilot as the Staff withdrew this recommendation. Additionally, the Commission adopts the ALJ's rejection of the recommendation that Consumers provide additional GIS data but encourages the parties to collaborate with the company in the future to make available the locations of Consumers' infrastructure and the types of maps that can be produced.

With respect to the seven-year effective clearing cycle for the LVD system, the Commission agrees with the ALJ that there is merit to MNSC's recommendation that customer costs of outages, the costs of service restoration, and the costs of line clearing should be incorporated into a formal optimization analysis of line clearing cycles, including the evaluation of shorter clearing cycles. Additionally, the Commission agrees that an analysis of the feasibility of more aggressive line clearing in everything outside of the first zone is a prudent first step in decreasing tree-related wire downs and improving service reliability. However, the Commission disagrees with the ALJ and finds that these issues are not beyond the scope of rate cases and that rate cases continue to be an appropriate forum to address these issues. Accordingly, the Commission directs Consumers to provide an analysis of the feasibility of more aggressive line clearing in everything outside of the first zone in the company's next rate case. The Commission further directs Consumers to perform a formal optimization analysis of line clearing cycles that accounts for customer costs of outages, the costs of service restoration, and the costs of line clearing, including an evaluation of shorter clearing cycles, and further agrees with MNSC that this analysis "should look with particularity to the customer costs and restoration costs associated with tree-caused outages and not at average values acrost all outages." 4 Tr 2650. The Commission also agrees with MNSC's argument that the company should include in this analysis the issues involving higher contractor costs, added vegetation data, and corresponding reliability concerns regarding the proposed nine-year clearing cycle for 4.8 kV circuits. Due to the potentially short timeframe in between rate case filings, the company is directed to file this formal optimization analysis of line clearing in Case No. U-20697 by September 3, 2024.

Additionally, as part of its projections for capital expenditures, Consumers provided testimony regarding its Scheduling Optimization project, including that the purpose of the project was "to better ensure the Company gets the right crew on site at the right time, so that field work can be completed right the first time and in a safe manner." 4 Tr 1772-1773. According to Consumers, the use of its Scheduling Optimization tool increased productivity by 25 percent, and the company projected that it would provide significant capital and O&M savings, including net O&M savings of $4.6 million in 2024-2025. Exhibit AG-1.9.

The Attorney General argued that Consumers failed to include projected savings from the Scheduling Optimization project in its O&M expenses for the test year and that, consequently, a downward adjustment of $4.6 million must be made. 4 Tr 3074; Exhibit AG-1.9. In response to this argument, Consumers asserted that the expected savings from the Scheduling Optimization project were applied across multiple programs and were accounted for when preparing cost projections for those programs. 4 Tr 1841. Accordingly, Consumers argued that the Attorney

General's recommended downward adjustment would result in a double counting of the savings that were already considered as part of the company's cost projections. 4 Tr 1841.

The ALJ agreed with the Attorney General and found that, consistent with her discussion on capital expenditure reductions from the Scheduling Optimization project,[14] a downward adjustment of $4.6 million for Consumers' Other O&M expenses should be approved. PFD, p. 390.

In exceptions, Consumers argues that the Commission should reject the ALJ's recommendation because that recommendation requires the tracking of exact savings from a single project, which the Commission has never previously required. Consumers' exceptions, pp. 30-32, 127. Alternatively, Consumers argues that even if the Commission agrees that there should be a disallowance, any reduction should not exceed $100,000, which is the total of the O&M expenses projected for the Scheduling Optimization project in the test year. *Id.*, p. 128.

In reply, the Attorney General argues that Consumers should be required to demonstrate the savings that it claims results from implementation of the project and that the Commission should adopt the ALJ's recommended reduction. Attorney General's replies to exceptions, pp. 36-37, 72-73.

The Commission has reviewed the record and the arguments by the parties and finds that, consistent with its findings (above in Part IV, Section A.1.a.ii.) for the Scheduling Optimization project related to capital expenditures, Consumers' quantification of the benefits of the project are persuasive. *See*, Exhibit AG-1.9, p. 1; 4 Tr 1771-1773. Accordingly, the Commission rejects the

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[14] The ALJ found that, although Consumers was not required to provide specific information on cost reductions for each program or project, it was concerning that Consumers could not provide even one example of a project cost that was reduced due to implementation of the Scheduling Optimization tool. PFD, pp. 39-43.

ALJ's recommended disallowance to O&M expenses and approves Consumers' proposed expenses of $1.2 million as reflected in Exhibit AG-1.9, p. 1, for 2022 through 2025, which includes $100,000 in projected expenses for 2024 and 2025.

3. Service Restoration Operations and Maintenance Expense and Performance Incentive

a. Service Restoration Costs

Consumers projected a service restoration O&M expense of $107 million, which is based on a five-year average of actual service restoration expenses from 2018-2022 plus inflation for 2023-2025.

The Staff supported Consumers' proposed service restoration O&M expense. *See*, 5 Tr 3959.

To calculate the service restoration O&M expense, the Attorney General's witness Sebastian Coppola used a five-year average of actual expense that is similar to Consumers' calculation. However, he disputed some of the expenses included in the company's calculation. Mr. Coppola noted that the service restoration costs in Figure 2 of Brenda Houtz's direct testimony are higher than the service restoration costs on line 23 of Exhibit A-131. He stated that he requested an explanation of the discrepancy and Ms. Houtz responded that the numbers in her testimony exclude particular insurance recovery credits. Mr. Coppola asserted that "[i]t is unclear why these credits should be excluded since they offset a portion of actual service restoration costs. In [his] calculations of the forecasted service restoration expense for the projected test year, [he] used the actual expense amounts from Exhibit A-131, which include the insurance recoveries." 4 Tr 3062.

In addition, Mr. Coppola recommended a $1.2 million offset for restoration cost savings due to forestry management. 4 Tr 3063. Accordingly, Mr. Coppola calculated a service restoration O&M expense of $102.99 million. Although he did not recommend an adjustment, Mr. Coppola noted that "the Company reported that it utilized at least 883 employees in Storm Pre-Staging activities in 2020 and forecasted that it would exceed 2,300 employees in 2021 and 2022, plus 2,500 outside contractors. It is not clear how much more value is being derived from the massive increase in people added to pre-staging activities." 4 Tr 3064 (footnote omitted).

In its initial brief, Consumers stated that:

> [t]here is no evidence on the record that the Company still receives insurance proceeds as an offset to service restoration costs. Indeed, the Company no longer receives these proceeds. In October 2019, it terminated its storm insurance, also known as transmission and distribution insurance, which was provided by Energy Insurance Services, Inc. If these proceeds were to exist again in the future—the Company has no plans to purchase this insurance again—they should not be considered together with service restoration costs. The level of insurance proceeds are incident-driven, and they are received sporadically, so the Company's un-offset service restoration costs are a better indicator of future costs than service restoration costs offset by sporadic insurance proceeds.

Consumers' initial brief, pp. 345-346.

Regarding Mr. Coppola's proposed offset for enhanced tree trimming, the company asserted that the proposed discount would penalize Consumers for providing more reliable and affordable service to customers. The company stated that Mr. Coppola's proposal "would disallow projected savings over 2022 savings on a one-to-one basis (each dollar of savings offsetting a dollar in service restoration costs) while diluting service restoration increases by averaging them over five years. This inconsistent approach should be rejected." *Id.*, p. 346.

The ALJ agreed with the Attorney General that there is record evidence that, in the past, the company's restoration costs have been offset by insurance proceeds or voluntary refund mechanism credits. *See*, PFD, p. 404 (citing 4 Tr 3062). She stated that:

> [w]hile Consumers maintains, with no record support, that it stopped purchasing insurance in 2019, this claim is belied by the fact that in 2021, the company's actual storm restoration costs of $168.9 million reported by Ms. Houtz were only $159.7 million after insurance or other offsets as shown in Exhibit A-131. Whether the amounts receive [sic] in 2021 pertained to some year or years prior is anyone's guess since the company did not provide any evidence in rebuttal explaining the discrepancy.

PFD, p. 404. In addition, the ALJ rejected Consumers' claim that an offset to restoration costs for enhanced tree trimming would penalize the company for providing better service. She asserted that "[t]he Attorney General's recommendation simply recognizes that the considerable investment in line clearing over the past several years is showing some pay off in terms of cost offset." *Id*. Thus, the ALJ recommended a storm restoration O&M expense of $102.99 million.

In exceptions, Consumers asserts that "there is no evidence on the record that the Company *still* receives insurance proceeds to offset service restoration costs." Consumers' exceptions, p. 131 (emphasis in original). Therefore, because there is no evidence that the company will continue to receive insurance proceeds, Consumers argues that it is unreasonable to use records of historical proceeds to offset projected storm restoration O&M expense. The company also objects to the ALJ's finding that Consumers' projected expense lacks accuracy because, in 2021, the company received insurance and other proceeds that offset its service restoration O&M expense. Consumers contends that the amounts received in 2021 were not insurance or other proceeds; rather, "[t]he 2021 service-restoration expense in Exhibit A-131 (MPK-12) . . . included $9 million in voluntarily repurposed funds approved in Case No. U-20932 for storm restoration. The footnote to Figure 2 in Ms. Houtz's testimony specifically said it accounts for spending approved through the voluntary refund mechanism." Consumers' exceptions, p. 132. Accordingly, the company asserts that it has not received any insurance proceeds since 2020.

In addition, Consumers disputes that its service restoration O&M expense should be offset by savings from the enhanced tree trimming program. Consumers states that "although the Company is reducing service restoration expenses by annually trimming more miles of line, all other things being equal, the savings are not enough to completely offset growing expenses caused by increasingly severe weather." *Id*., p. 133.

In response to Consumers' claim that 2021 service restoration O&M expense was offset by the voluntary refund mechanism, the Attorney General cites the PFD wherein the ALJ noted that the company claimed that it excluded "voluntary refund mechanism credits if applicable to the year." Attorney General's replies to exceptions, p. 77 (citing PFD, p. 403). Additionally, the Attorney General objects to Consumers' argument that its service restoration O&M expense should not be offset by savings from the enhanced tree trimming program. The Attorney General asserts that "the Commission's order dated December 22, 2021 in Case No. U-20963, directed the Company to provide a more detailed analysis of those cost savings in subsequent rate cases. [The Attorney General]'s approach is consistent with the Commission's order." Attorney General's replies to exceptions, p. 78 (footnote omitted).

The Commission finds the Attorney General's position persuasive. Although Consumers contends that its storm insurance coverage ended in 2019, the company's 2020 storm restoration expense of $75 million was offset by approximately $4 million and its 2021 storm restoration expense of $168 million was offset by approximately $9 million. *See*, 4 Tr 1677; Exhibit A-131. Consumers claims that the $9 million offset was from voluntarily repurposed funds approved in Case No. U-20932 for storm restoration and that "the footnote to Figure 2 in Ms. Houtz's testimony specifically said it accounts for spending approved through the voluntary refund mechanism." Consumers' exceptions, p. 132. However, the footnote states that Figure 2 "[e]xcludes insurance recovery and voluntary refund mechanism credits if applicable to the year." 4 Tr 1677, Figure 2, n. 2. Accordingly, the Commission finds that the company's explanation of the offset is contradictory.

The Commission finds that there is record evidence demonstrating that Consumers' 2018, 2020, and 2021 storm restoration expenses were offset by some type of proceeds, whether it be insurance or other credits. *See*, 4 Tr 1677; Exhibit A-131. The Commission agrees with the Attorney General that any insurance proceeds and voluntary refund mechanism credits received by Consumers from 2018-2022 should be included in the five-year average of actual service restoration O&M expense. However, the Commission finds that Consumers' proposed inflation factor of 0.40% should be applied, resulting in a five-year service restoration O&M expense of $104.23 million.

In addition, as noted by the Attorney General, in the December 22 order, the Commission directed Consumers to "provide a more detailed analysis of savings expected from its distribution capital and O&M spending in future rate cases . . . ." December 22 order, pp. 259-260. In this case, Ms. Houtz testified that as a result of the enhanced tree trimming program, potential avoided costs to service restoration O&M in the test year are $2.9 million. *See*, 4 Tr 1687, Figure 10. The Attorney General noted that this is $1.2 million more than the $1.7 million in actual avoided costs for 2022. *See*, 4 Tr 3063. Therefore, the Commission finds that the Attorney General's recommended $1.2 million offset for restoration cost savings due to forestry management is reasonable and prudent and should be approved.

The Commission also reminds the company that the rates it collects are not a reward for doing a good job, and conversely, lowering a revenue requirement does not "penalize Consumers for providing more reliable and affordable service to customers." Consumers' reply brief, p. 346. Instead, rates are set to be reflective of the cost to serve customers.

b. Symmetric Performance Incentive Mechanism

Consumers requested "a Symmetric Performance Incentive Mechanism [(SPIM)] for service restoration O&M expenses that would allow the Company to defer some service-restoration expenses when they exceed amounts included in rates while also providing the Company an incentive to control costs and giving customers a refund when service-restoration expenses fall below amounts included in rates." Consumers' initial brief, p. 342 (citing 4 Tr 1696).

The Staff contended that Consumers' proposed SPIM should be rejected because:

> 1) Staff is supporting the full service restoration expense for the test year, 2) the Commission rejected similar mechanisms in prior cases U-20963 and U-20697, 3) DTE Electric [Company (DTE Electric)] does not have this mechanism for its storm restoration expense, and 4) [i]n Case U-21305 the Commission ordered a third-party audit be completed by a consultant who will investigate Consumers['] and DTE [Electric]'s distribution systems. After the audit is completed, the results may show cost savings for Consumers Energy. A tracking mechanism like the [SPIM] should not be approved when there are potential cost savings the Company could gain.

5 Tr 3960-3961.

The Attorney General and MNSC also objected to the SPIM. *See*, 4 Tr 2665, 3087-3088. The Attorney General asserted that the SPIM "is not a performance incentive mechanism. It is simply a cost deferral and recovery mechanism with a 10% retainer. [The Attorney General] will note that in Case U-21224, the Company had proposed to refund 100% of any over-recoveries over a threshold level. Therefore, the SPIM with a 10% retainer is a worse proposal for customers." 4 Tr 3088.

Consumers responded that the SPIM is the company's response to the Commission's request for Consumers to improve reliability. The company noted that as of August 2023, it has incurred approximately $160 million in service restoration expenses and expects the expenses to increase to $200 million by year-end 2023, which far exceeds the $105 million projected in the company's initial filing. *See*, 4 Tr 1712. Consumers stated that, "[a]s 2023 is demonstrating, when severe weather strikes, actual service restoration costs can diverge, even drastically, from the amount the Company included in its projected test year based on a five-year average. The [SPIM] would allow the Company to manage this risk of volatility while maintaining an incentive to efficiently manage resources dedicated to service restoration." 4 Tr 1713. Although the Commission has rejected prior similar mechanisms, Consumers contended that it has made changes, compared to previous proposed mechanisms, and that the SPIM "strikes the right balance." 4 Tr 1714.

Finally, Consumers disputed the Staff's recommendation to delay implementation of a performance incentive mechanism until the ongoing third-party audit of Consumers' and DTE Electric's distribution systems is complete. The company argued that the "proposed mechanism would not undermine the Company's ability to address potential findings from the distribution audit." 4 Tr 1714.

The ALJ recommended that the SPIM be approved. She noted that "[a]s amply shown in the company's testimony and exhibits, storm restoration costs, while generally trending upward, remain quite volatile. Thus, a mechanism like that proposed here will protect ratepayers from overpaying for storm restoration expense, while the 10% deadband for spending above the amount set in rates, encourages the company to control restoration costs." PFD, p. 408.

In exceptions, Consumers acknowledges the ALJ's recommendation to approve the SPIM as "forward-thinking." Consumers' exceptions, p. 129. However, the company contends that if the Commission declines to adopt the ALJ's recommendation, Consumers states that it "will zealously pursue the full $107 million it requested. Every dollar spent quickly restoring customers' power translates into shorter outages for its customers, and they deserve no less." *Id.*, pp. 129-130.

The Staff excepts, reiterating that the SPIM should be rejected for the reasons set forth in the Staff's testimony and briefing. The Staff disagrees with the ALJ that the SPIM will "protect ratepayers from overpaying for storm restoration expenses due to the increases in storms each year." Staff's exceptions, p. 4.

The Attorney General also excepts, arguing that "a cost deferral and recovery mechanism can incentivize the Company to increase cost instead of controlling them in future years because it would be able to pass through large cost increases to customers." Attorney General's exceptions, p. 41.

Consumers disputes the Staff's contention that the SPIM is unnecessary and should be disallowed because the Staff supports the company's proposed service restoration O&M expense. The company states that the Staff's support is immaterial because the ALJ recommended that the Commission approve an O&M expense lower than what was requested by the company. Furthermore, according to Consumers, the ALJ's recommended service restoration expense does not account for the volatile weather that has been occurring and the SPIM will allow the company to manage the volatility. Regarding the Staff's second claim that the Commission should not approve the SPIM because other utilities do not have a similar mechanism, Consumers argues that this is no reason to reject the mechanism. The company states that its "service territory is obviously different than DTE Electric's and may merit different approaches to storm restoration." Consumers' replies to exceptions, pp. 68-69 (citing 4 Tr 1714). Although the Staff asserts that the Commission has rejected similar proposals in the past, Consumers asserts that times have changed, weather has intensified, and the company has made progressive changes to its proposal.

Consumers agrees with the Staff that "the ongoing distribution audit may expose opportunities for cost savings," however the company argues that it also "may reveal the need for additional distribution capital investments and operations and maintenance ('O&M') spending. The Company's proposed mechanism would not undermine the Company's ability to address potential findings from the distribution audit." Consumers' replies to exceptions, p. 69 (internal citation omitted). Consumers also asserts that the SPIM was proposed and supported by interested persons during engagement sessions, particularly by MNSC in Case No. U-21224.

Next, Consumers objects to the Attorney General's argument that the SPIM "does not incentivize any specific level of performance because 'any over or under-recoveries would be retained in a regulatory liability or regulatory asset account until addressed in a future rate case.'" Consumers' replies to exceptions, p. 70 (quoting Attorney General's exceptions, p. 40). The company asserts that the Attorney General mischaracterizes the SPIM and argues that the mechanism "strikes the right balance between managing customer costs and enabling the Company to complete its many critical customer work programs in an environment of increasingly volatile storm activity." *Id*. (citing 4 Tr 1697).

In addition, Consumers disputes the Attorney General's claim that the company has unreasonably added hundreds of people to its storm response teams and, therefore, unnecessarily increased costs. The company responds that it "has pre-staged more crews on location who are ready to quickly restore power before severe weather strikes. Ms. Houtz estimated that the Company's pre-staging tactics reduced customer outage times in 2022 by over 65 SAIDI minutes." *Id*., p. 71 (citing 4 Tr 1693). Consumers contends that the SPIM will ensure that the company can recover service restoration O&M expenses when they are higher than approved in rates.

The Commission notes that, according to Consumers, the SPIM should be approved because it benefits customers. However, the Commission finds that Consumers has not demonstrated that the SPIM will sufficiently control service restoration expenses as claimed by the company. In its initial brief, Consumers explains that:

> [i]n the bad years, the Company could defer and ultimately recover 90% of its excess service-restoration expense (i.e., expenses above approved amounts included in rates), with the first 10% being offset by the Company as an incentive to control its costs. In the good years, customers would receive a refund for 90% of expenses

> below approved amounts included in rates, with the Company retaining the first 10% as, again, an incentive to control costs.

Consumers' initial brief, pp. 347-348. As noted by the Attorney General, Consumers fails to specify a level of performance to be incentivized by the SPIM. In addition, the SPIM does not incentivize the company to reduce service restoration expenses more than 10% below that approved in rates. Furthermore, there is no evidence demonstrating that the 10% offset would adequately deter the company from passing through large cost increases to customers. Finally, the Commission finds that approval of the mechanism is premature given the ongoing audit in Case No. U-21305. Therefore, the Commission finds that the SPIM should not be approved.

4. Power Generation Operations and Maintenance Expense

Consumers projected a fossil and hydro generation O&M expense of $164.25 million, which was revised in rebuttal to $145.13 million, after recommended adjustments from the Staff and the company. *See*, 4 Tr 912, 941-942.

The Staff proposed a $1.2 million disallowance for solar O&M related to the delay of in-service dates for three solar facilities: Mustang Mile, Washtenaw, and Muskegon. Consumers objected, asserting that "[t]he funding requested is for the hiring and apprenticeship training of solar specialists for both Mustang Mile and Muskegon solar facilities. Consumers Energy [e]xpects to commission numerous utility scale solar projects during or shortly following the projected test year." 4 Tr 942. The Staff responded that although hiring and training of apprentices may have value, there is uncertainty that the expenses will be incurred during the projected test year. The Staff also noted that Consumers may request recovery of the expenses in a future rate case.

In reply, Consumers contended that apprenticeship training is scheduled to begin on July 1, 2024. Additionally, the company stated that the "Staff's argument does not recognize that these dollars are O&M dollars – not capital dollars. If the Company spends these dollars beginning July 1, 2024 to hire and train these employees, the Company cannot recover these dollars in a later rate case." Consumers' reply brief, p. 55.

The ALJ recommended that the Staff's disallowance be rejected. She stated that "[w]hile the in-service dates for the Mustang Mile, Washtenaw, and Muskegon solar facilities remain uncertain, the 18-month lead time for apprentice training appears set to begin in July of 2024. As the company points out, O&M expenses, unless accounting authority is granted for a deferral, cannot be recovered in a later rate case." PFD, p. 409.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

5. Facilities, Real Estate, Supply Chain Operations and Maintenance Expense

The ALJ noted that "while the company did remove the capital expenditures for the Control/Dispatch Center Consolidation project, conceding Staff's 20% reduction for employee relocation, Consumers did not remove the $200,034 of test year O&M related to the same disallowance, to which the company also agreed." PFD, p. 410 (footnote omitted). She stated that the $200,034 reduction in facilities, real estate, and supply chain O&M expense is reflected in the revenue requirement set forth in the PFD.

In exceptions, Consumers "agrees that it accepted Staff's proposed $200,000 reduction in test year O&M associated with the Control/Dispatch Center Consolidation and that the final revenue requirement approved in this case should reflect that reduction." Consumers' exceptions, p. 134.

No replies to exceptions were filed. The Commission finds that the ALJ's recommendation should be adopted.

6. Customer Experience Operations and Maintenance Expense

Consumers' CX&O is comprised of two areas: customer interactions, and billing and payment. The company projected $48 million for the CX&O O&M expense, which was reduced by $7.88 million related to an adjustment for credit card fees.

a. Customer Interactions

Consumers projected $28.8 million for customer interactions, which includes digital, telephone, and mail for customers to communicate with the company.

The CEOs proposed that the funds from LIHEAP, MEAP, LIEAF, LIA, and RIA be pooled "into a Percent of Income Payment Plan (PIPP) for LMI [low- to moderate-income] households and securing additional rate-payer funding for such a plan" because it "would be a sensible, short-term, bill-assistance solution to closing the $475 million LMI energy affordability gap in the short term." 4 Tr 3311.

Consumers responded that on February 10, 2022, the Commission approved a two-year PIPP pilot in Case No. U-21021 that began in October 2022. The company asserted that after the pilot concludes, Consumers "will be able to utilize information gained during the pilot phase to determine the feasibility of launching PIPP as an ongoing program" and that "it would be inappropriate to make any changes to the PIPP pilot until the initial two-year pilot is complete." 4 Tr 1554. The Staff agreed, and also argued that it may not be lawful to use some of the funds in the manner suggested by the CEOs.

The ALJ found Consumers' position persuasive, asserting that any changes or expansion of the program should be rejected until the pilot program is complete. In addition, she stated that:

> recognizing the limited time available to address the manifold and complex issues presented in a rate case, this PFD observes that any significant reimagining of the company's customer assistance efforts and programs should first be addressed in other proceedings such as the Low Income Energy Policy Board, the Energy Affordability and Accessibility Collaborative, or the Low Income Workgroup.

> Once some consensus is reached via discussions in these alternative forums, a proposal could be included as part of a future rate case.

PFD, p. 413.

UCC excepts, asserting that the ALJ "improperly recommended that matters relating to affordability, such as changes to the Company's affordability assistance programs and potential additional affordability analysis, not be handled in the rate case, pushing them to other proceedings." UCC's exceptions, pp. 12-13 (footnote omitted). UCC argues that customers are primarily concerned with affordability and that the Michigan Legislature has directed the Commission to focus on customer affordability issues. UCC contends that the ALJ failed to adequately consider the urgency for affordability and that the Commission should reject her recommendation.

Consumers agrees with UCC that affordability is a factor in setting rates and states that the company's full rate request will not be burdensome on the "typical residential electric customer." Consumers' replies to exceptions, p. 109. The company asserts that it "takes actions to mitigate the customer bill impact of its necessary investment plans" and "offers a range of customer assistance options." *Id*., p. 110. Consumers supports the ALJ's recommendation and contends that these workgroups are the appropriate venue to consider these issues.

In its replies, UCC argues that the ALJ's recommendation that the "parties have access to the information they need in a timely manner" is unclear and confusing. *See*, UCC's replies to exceptions, p. 2 (quoting PFD, p. 560). UCC requests that the Commission direct Consumers to provide information regarding customers who experience multiple interruptions and customers who experience long interruption duration, along with EJ analyses, in the company's next rate case. In particular, UCC requests that the Commission incorporate these proposals in the rate case filing requirements.

The Commission finds that the ALJ's recommendation should be adopted. As noted by Consumers and the ALJ, the PIPP pilot in Case No. U-21021 is not complete and until that information is available, it would not be prudent to make changes to the PIPP. In addition, the Commission agrees with the ALJ that workgroups, such as the Low Income Energy Policy Board, the Energy Affordability and Accessibility Collaborative, and the Low Income Energy Waste Reduction Workgroup, are the more appropriate forums to consider these issues, in turn incorporating input from these forums into rate case processes. Additional findings on topics of environmental justice (EJ), grid equity, and affordability follow in Section VIII.

GLREA noted that $0.91 per meter per month is collected from every customer to fund the LIA program. GLREA argued that it is nonsensical to collect this charge from customers receiving LIA aid because "the assistance is actually 25% less as $1/month goes back into the program." 4 Tr 3203. GLREA asserted that customers receiving LIA should be exempt from the monthly per meter charge. In addition, GLREA asserted that it is inequitable for all customers to pay the same fee regardless of usage. GLREA contended that "[f]or a residential customer that pays $100/month, the assistance is 1% of their bill. For a primary customer that pays $100,000/month, the assistance is 0.001% of their bill. Thus, in [GLREA's] opinion, the industrial and commercial customers are not paying their share." 4 Tr 3204. GLREA recommended that the Commission adjust the funding mechanism to charge all customers $0.002/kWh.

Consumers disagreed, asserting that:

> [w]ithout even getting into the merits of [GLREA]'s criticisms, the Company does not agree with [GLREA]'s proposal because it is contrary to Public Act 95 of 2013 (PA 95), the statute that authorizes collection of the surcharges for the fund. 4 TR 1554; see MCL 460.9t. PA 95 requires that the surcharge be (i) assessed on a per-meter basis (not per-kilowatt-hour), (ii) the same across all customer classes, and (iii) no greater than $1.00. MCL 460.9t(6) and (9)(b). [GLREA]'s proposal would violate all three of those legal requirements. The statute is also clear that the surcharge must be nonbypassable. MCL 460.9t(9)(b).

Consumers' initial brief, pp. 362-363.

The ALJ stated that for the reasons set forth in Consumers' initial brief, GLREA's proposal should be denied. *See*, PFD, p. 414.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

b. Billing and Payment

No party proposed adjustments to Consumers' billing program. For the customer payment program, the company initially proposed $9.21 million in O&M expense but reduced the request by $7.88 million to reflect Consumers' change in policy regarding credit card payment fees. The ALJ found the adjustment to be reasonable and recommended Commission approval of $1.3 million for the customer payment program. *See*, PFD, p. 415.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

7. Corporate Services Operations and Maintenance Expense

Consumers explained that corporate services O&M expense is shared between the company's gas and electric utilities and allocated accordingly. The company proposed $59.72 million, which includes an adjustment for inflation, for the electric utility corporate services O&M test year expense. 4 Tr 1355-1358; Exhibit A-83.

The Staff recommended an adjustment to Consumers' expense that was related to the company's employee incentive compensation program, which is set forth in Exhibit S-15.1. 5 Tr 3892-3893. In rebuttal, Consumers accepted the proposal and adjusted the corporate services O&M expense accordingly. 4 Tr 1373-1374. The ALJ recommended that the Staff's proposed adjustment be approved. *See*, PFD, p. 415.

No party filed exceptions regarding the Staff's proposed adjustment and the Commission finds that it should be approved.

The Attorney General asserted that Consumers increased its corporate services O&M expense by $7.1 million over the historical year expense, mostly due to insurance premium increases. She stated that according to the company, insurance premium refunds or distributions from Energy Insurance Mutual (EIM), Industry Credit Rating Plan (ICRP), and Associated Electric and Gas Insurance Services (AEGIS) are received annually and can vary from year to year. The Attorney General noted that "distributions over the past five years have ranged from as low as $912,000 in 2020 to $1,551,000 in 2019 at the high end. [Consumers] advocated using a five-year average of distributions from these insurers and included $1,065,000 as a credit against O&M expense in the projected test year." 4 Tr 3071. She contended that because of the variable nature of these distributions, a five-year average "is a very reasonable approach." 4 Tr 3071.

However, the Attorney General noted that Consumers declined to use a five-year average for insurance cash distributions from the Nuclear Electric Insurance Limited (NEIL) agency and, instead, included an estimated amount for the projected test year. The Attorney General stated that, in discovery, she requested that the company:

> provide the NEIL guidance received recently and in prior years. The information provided in response to the discovery request shows both the actual distributions made and the guidance given about future distribution from 2018 through 2022. The actual distributions consist of both (a) primary distributions, and (b) supplemental distributions. As can be seen from the information provided in the discovery response, NEIL only gives guidance with respect to primary distributions. For example, the $700 million distribution to all NEIL clients shown in the chart on page 9 of [Matthew] Foster's direct testimony consists of a $290 million primary policy holder distribution and a supplemental distribution of $410 million. However, in the guidance provided one year earlier, NEIL projected only a primary distribution of $250 million.

4 Tr 3072 (footnotes omitted). The Attorney General asserted that reliance on NEIL guidance for projecting future cash distributions is unreliable because NEIL does not project supplemental distributions. She stated that "the Commission should reject the Company's approach of relying on NEIL guidance about partial future cash distributions and instead adopt the use of historical cash distributions received in the most recent five years." 4 Tr 3073. Using this approach, the Attorney General recommended that the Commission include a $5.1 million offset to Consumers' proposed corporate services O&M expense.

In response, Consumers stated that "there have been higher-than-normal distributions in years 2018 through 2022" and a five-year average of these distributions is $9.41 million. 4 Tr 1358. However, the company asserted that the "preliminary actual distribution" for 2023 is $2.9 million and that Consumers expects to receive $4.3 million in 2024 and 2025. 4 Tr 1358. Therefore, Consumers contended that a five-year average is not an accurate projection for distribution amounts.

The ALJ reviewed Exhibit AG-1.44, which contains the NEIL guidance submitted by Consumers in response to the Attorney General's discovery request. She stated that "[a]s the Attorney General points out, and Consumers does not refute, it does appear that the NEIL guidance on future refunds pertains to primary distributions only and that past distributions to Consumers have included both primary and supplemental distributions." PFD, p. 417. Thus, the ALJ found that the Attorney General's proposed adjustment should be approved.

Consumers excepts, reiterating that using a five-year average is not appropriate because "there have been higher than normal distributions in years 2018 through 2022. Instead, the Company supports using the NEIL Member Financial Outlook as the most accurate policyholder distribution expectation." Consumers' exceptions, p. 135 (internal citation omitted).

The Attorney General disagrees, reiterating that in 2018, NEIL provided guidance that the 2019 distribution would be $250 million. However, she notes that the actual 2019 NEIL policyholder primary distribution was $290 million and the supplementary distribution was $410 million. *See*, Attorney General's replies to exceptions, pp. 81-82.

The Commission finds the ALJ's recommendation persuasive. As noted by Consumers and the Attorney General, the NEIL guidance set forth in Exhibit AG-1.44 provides future projections for primary distributions but not supplemental distributions. However, Exhibit AG-1.44 does provide the actual primary and supplementary distributions to Consumers for 2018-2022. In 2018, the NEIL guidance projected a primary distribution of $250 million for 2019. The actual primary distribution in 2019 was $290 million and the supplementary distribution was $410 million. In 2019, the NEIL guidance projected a $225 million primary distribution for 2020. The actual primary distribution in 2020 was $290 million and the supplementary distribution was $110 million. For 2021, the NEIL guidance projected a $225 million primary distribution. In 2021, the actual primary distribution was $290 million and the supplementary distribution was $310 million. For 2022, the NEIL guidance projected a $225 million primary distribution. In 2022, the actual primary distribution was $150 million and there was no supplemental distribution. These amounts were not contested by Consumers; rather, the company requested that the Commission rely only on NEIL guidance for the projected primary distribution for the test year. *See*, Exhibit AG-1.44; 4 Tr 1378. The Commission finds that after a review of the 2018-2022 primary and supplemental distributions, it is reasonable to adopt a five-year average of NEIL distributions and approves a $5.1 million offset to corporate services O&M expense.

8. Information Technology Operations and Maintenance Expense

The ALJ stated that "[c]onsistent with this PFD's determination that capital costs associated with the company's mobile app and BDDT project [should be disallowed], this PFD also finds that O&M expense disallowances of $49,044 for the mobile app and $417,300 for the BDDT project should be adopted." PFD, p. 417.

In exceptions, Consumers states that "[t]he Commission should reject these proposed disallowances for the reasons discussed above in these Exceptions related to the IT capital expenditures for these programs." Consumers' exceptions, p. 134.

The Attorney General states that her "response to the Company's capital expenditure exceptions also apply to these expenses as well." Attorney General's replies to exceptions, p. 79 (footnote omitted).

The Commission finds that the $49,044 in IT O&M expense for the mobile app should be approved for the reasons set forth in the Customer Self-Service Mobile Application section in the IT capital expenditure section above. The Commission finds that Consumers provided evidence demonstrating that there has been increased usage of the app and that it offers many customer benefits such as bill payment, outage reporting, eBill enrollment, notification alert sign-up, auto pay enrollment, and budget plan enrollment. The company states that "[s]ince adoption, the mobile app has accounted for 18.5% of all customer interactions and ranks as the second (out of 10) most popular customer communication channel." 4 Tr 1518.

However, the Commission finds that the O&M expense for the BDDT project was not sufficiently supported. As noted above, Consumers claims that the project will provide $16 million in savings; however, Exhibit A-181 shows the savings to be $2.5 million annually.

Because of the inconsistency in Exhibit A-181 and the benefit-cost ratio set forth in the record, the Commission finds that the O&M expense for the BDDT project should be disallowed.

9. Security Operations and Maintenance Expense

The ALJ found that no party objected to Consumers' security operations and security investment expenses set forth in Exhibits A-77 and A-78. She recommended that these expenses be approved. *See*, PFD, p. 417.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

10. Pension and Benefits Operations and Maintenance Expense

The ALJ noted that there were no disputes regarding healthcare, life insurance, long-term disability, or other benefits expenses, and no party objected to the pension and other post-employment benefit (OPEB) expenses. She recommended that the Commission approve these expenses. *See*, PFD, p. 418.

No exceptions were filed regarding the ALJ's recommendations for healthcare, life insurance, long-term disability, or other benefits expenses. The Commission finds the ALJ's findings and recommendations for these issues to be reasonable and prudent and that they should be adopted.

Consumers asserted that defined benefits (DB) and OPEB expenses are sensitive to changes in asset returns and other assumptions, which results in the possibility for significant variability in future expenses. In the company's opinion, a mechanism that reduces or eliminates the risk of future volatility in these expenses would be beneficial for customers. Accordingly, Consumers proposed a DB pension/OPEB volatility mechanism that:

> would allow the Company to defer annually the difference between the DB Pension/OPEB expense included in rates versus the actual annual DB Pension/OPEB expense recorded by the Company pursuant to ASC 715. If actual annual DB Pension/OPEB expense is less than the expense approved in rates, the

> Company proposes that this difference would be recognized as a regulatory liability and be amortized over 10 years starting the following January. Similarly, if actual annual DB Pension/OPEB expense is greater than the expense approved in rates, the Company proposes that this difference would be recognized as a regulatory asset and be amortized in the same manner. Any amortization of these regulatory assets or liabilities would be included in future general rate cases. Another benefit of the DB Pension/OPEB Volatility mechanism is that it supports the goal to maximize market returns on significant investments while minimizing the benefit expense volatility for customers.

4 Tr 1394.

The Attorney General objected to Consumers' proposed mechanism, asserting that it is more beneficial to the company than to customers. She stated that:

> [t]hese proposals for deferral mechanisms seem to flourish during periods when pension and OPEB expenses are bound to decline. If pension and OPEB expenses are likely to decline in coming years, it is best to passthrough the lower expense to customers as quickly as possible to offset other cost increases, instead of spreading the lower expense benefit over 10 years.
>
> The Company has not presented any evidence of significant upcoming pension and OPEB expense volatility that supports the decision to adopt a deferral mechanism. Therefore, there is no basis for the Company to argue that the proposal has merit.

4 Tr 3086. MNSC expressed similar concerns and contended that Consumers failed to explain how the mechanism will protect ratepayers, rather than the company, from volatility.

Consumers argued that the Attorney General's and MNSC's concerns are unfounded. The company reiterated that the proposed mechanism:

> addresses the significant potential for large variability in future expenses as a result of a change in asset returns or other assumptions which are unknown at the time the expense is projected. The mechanism operates symmetrically to create a regulatory liability where the actual expense is less than the amount approved in rates or a regulatory asset where the actual expense is more than the amount approved in rates, with the asset or liability amortized and included in future general rate cases.

4 Tr 1427. In addition, Consumers asserted that it "has previously been authorized to implement the Pension and OPEB Volatility Mechanism pursuant to settlement agreements in its most recent electric and gas rate cases." Consumers' initial brief, pp. 374-375.

In its initial brief, the Staff noted that it supports Consumers' proposed mechanism and asserted that customers would benefit from the mechanism. *See*, Staff's initial brief, pp. 210-211.

The ALJ recommended that the DB pension and OPEB volatility mechanism be approved for the reasons stated by Consumers and the Staff. The ALJ asserted that she "finds persuasive Staff's support for the proposal, the fact that the Commission has adopted a similar mechanism for DTE Electric and that the mechanism has been included in settlements in previous Consumers' gas and electric rate cases." PFD, p. 420.

The Attorney General excepts, reiterating that the DB Pension/OPEB volatility mechanism is more beneficial to Consumers than ratepayers. She states that:

> if pension and OPEB expenses decline in the coming years, it is better for customers that the lower expense be passed through to them quickly to offset other cost increases instead of spreading it over 10 years. Finally, it is not clear how a deferral mechanism would provide an incentive for maximizing returns on pension and OPEB assets and investments. The Company is already obligated to do so.

Attorney General's exceptions, p. 42 (footnotes omitted).

In response, Consumers states that it "fully supported the reasonableness of the proposed mechanism" and reiterates the benefits of the DB Pension/OPEB volatility mechanism. Consumers' replies to exceptions, p. 76.

The Commission agrees with the ALJ and finds that the DB Pension/OPEB volatility mechanism should be approved. As noted by Consumers and the Staff, DB pension and OPEB expense is sensitive to changes in asset returns and other assumptions and, as a result, is subject to potentially large swings in future expenses. The mechanism operates symmetrically and helps to protect ratepayers from future volatility in the expense. If the actual annual expense is less than what is approved in rates, Consumers will recognize the difference in amounts as a regulatory liability and amortize the difference over 10 years. If the actual annual expense is greater than the amount approved in rates, Consumers will record the difference as a regulatory asset and amortize the amount over 10 years. The Commission finds this method reasonable and prudent and recognizes that a similar mechanism has been approved for DTE Electric and included in settlements in previous Consumers' gas and electric rate cases.

11. Employee Incentive Compensation Plan Expense

To begin, Consumers noted that it is not requesting recovery of the portion of employee incentive compensation plan (EICP) expense that relates to financial incentives; rather, the company is requesting recovery of EICP expense that relates to operational measures. *See*, 4 Tr 1234-1235; *see also*, Consumers' initial brief, p. 380. Consumers explained that non-officer employees receive a base salary and are eligible to receive annual incentive compensation. The company stated that officers receive a base salary, annual incentive compensation, and long-term incentive compensation. Consumers noted that it is not seeking recovery of long-term incentive compensation. *See*, 4 Tr 1220.

Consumers asserted that Exhibit A-73:

> identifies the operational performance areas that the EICP focuses on and identifies the specific measures that have been adopted for each of these areas. For the 2022 historical year, 50.0% of the non-officer incentive compensation was based on operational performance. Beginning in January 2022, 30% of officer incentive compensation is based on operational performance. There was no change to the non-officer operational performance weighting in 2022. For purposes of this rate case the Affordability (O&M savings) measure associated costs has been removed from the rate request as the Company has determined that it is financial in nature.

4 Tr 1235; *see*, Consumers' initial brief, pp. 379-380. In addition, Consumers noted that in the third quarter of 2023, it will be updating its job architecture and, as a result, the company's compensation programs will be reviewed. However, the company stated that "[n]o specific EICP changes are known for the test year as of the date of this filing." 4 Tr 1236.

Next, Consumers noted that Exhibit A-73 provides the payout levels. The company explained that:

> [w]hen setting payout levels, threshold is set at a level of achievement that can typically be reached 80 to 90% of the time in a ten-year period. Maximum payout is for exceptional performance (10% to 20% of the time in a ten-year period). These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits.

4 Tr 1238; *see*, Consumers' initial brief, p. 381. In addition, Consumers stated that beginning in 2022, the operational goal payout levels changed from absolute goal achievement to individual banded goals. Furthermore, the company asserted that it combined gas and electric performance measures to improve efficiency and service.

Consumers asserted that the operational goals for which it is seeking recovery of EICP expense are: (1) employee safety, (2) culture index, (3) customer experience, (4) electric reliability, and (5) methane emission reduction. The company stated that it is requesting recovery of $2.4 million for this expense. *See*, 4 Tr 1240; Exhibit A-75; *see also*, Consumers' initial brief, p. 375. Consumers contended that the EICP is not a bonus or profit-sharing plan and that it benefits customers because "it is based on predetermined goals and objectives and award levels. Incentive compensation is part of an employee's overall compensation and not in addition to it . . . ." 4 Tr 1245. Moreover, the company argued that the EICP is a "carve out" of the employee's base salary and, therefore, is achieved without additional expense to customers. 4 Tr 1246. Consumers also asserted that the EICP assists the company in attracting, retaining, and motivating talented employees and executives, which in turn provides both qualitative and quantitative customer benefits.

Finally, Consumers provided Exhibits A-157 through A-160, which contain details regarding the 2023 EICP operational goals, the customer benefits of employee safety, the customer benefits of reliability, and the benefits of reduced employee turnover. In addition, the company explained the payout levels for each goal and a description of the direct quantitative benefits Consumers has identified. *See*, 4 Tr 2321-2331; Consumers' initial brief, pp. 381-382.

The Staff stated that it supports Consumers' request for $1.96 million in EICP expense for non-union employees that is based on operational measures, but it recommended that the EICP expense of $440,800 for Consumers' top five officers be excluded from the projected test year O&M expense. The Staff explained that, according to Consumers, "[e]mployees' salaries should be comparable to the market median;" however, when the "Staff asked for the compensation level of the top five officers compared to market median . . . [t]he Company declined to provide this information to Staff (see Staff 16 Exhibit S-16,1, page 1 of 2), stating that the information is confidential." 5 Tr 3902. Therefore, because the Staff could not review the confidential information, it requested that the $440,800 EICP expense for the company's top five officers be disallowed.

The Attorney General noted that after a review of Consumers' previous two years of EICP measures, she found that two previous operating performance measures—customer on-time delivery measure and service on-time commitment metric—are no longer included in the EICP. The Attorney General stated that these metrics were redundant and agreed with the company that they should be removed from the EICP. Regarding the methane emission reduction metric, she argued that "it is questionable if it belongs within the employee performance metrics. Most employees have little impact on achieving this metric." 4 Tr 3077-3078; *see*, Attorney General's initial brief, pp. 173-174.

The Attorney General asserted that the short-term incentive plans for officers and non-officers "are too heavily weighted toward financial measures that mostly benefit shareholders and not customers." 4 Tr 3078; *see*, Attorney General's initial brief, p. 172. The Attorney General also contended that Consumers' calculation for cost savings and purported customer benefits for reduced safety incidents, improved system reliability, and reduced employee turnover was speculative and unclear. *See*, 4 Tr 3079-3081; Attorney General's initial brief, pp. 178-181. Finally, she stated that "[t]he Company's proposed incentive compensation expense of $2.4 million for the projected test year assumes that it will achieve target performance for all its goals. There is no track record with the revised performance measures that supports that conclusion. It is probable that the Company may fall short of achieving 100% of the performance measures." 4 Tr 3082. The Attorney General recommended that the Commission approve EICP expense of $1.20 million related to operating measures and disallow the remaining $1.20 million. 4 Tr 3082.

ABATE recommended that the Commission only approve 62% of Consumers' requested EICP expense. According to ABATE, the company's projected EICP expense presumes that Consumers will pay 100% of the budgeted amount. Rather, ABATE asserted that "[a] review of the data shows that Consumers tends to pay out less than its budgeted amount. Over the five-year period from 2018 through 2022, Consumers paid out about $10.8 million of incentive compensation tied to operational performance, while it had budgeted about $17.5 million. Thus, Consumers has averaged a payout of about 62% of its budget." 4 Tr 2816; *see*, ABATE's initial brief, p. 43. ABATE contended that the Commission should approve $1.49 million for the company's projected EICP expense. *See*, 4 Tr 2816.

In response, Consumers objected to the Attorney General's request that the methane emission reduction metric be removed from the employee performance metrics. The company asserted that "[s]ome employees will be in a better position to influence whether particular goals and objectives are met, but having every employee linked to a set of common customer-focused objectives is an effective method for emphasizing the importance of customer value and service." 4 Tr 1253. Additionally, Consumers disagreed with the Attorney General's claim that the company's short-term EICP is too heavily weighted toward financial measures. The company asserted that it is not seeking recovery of EICP expense related to financial measures; rather, Consumers "has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers." 4 Tr 1254. Consumers also disputed the Attorney General's claim that mediocre performance will be rewarded by the company's EICP. Consumers stated that "[t]he incentive compensation portion of the Company's total compensation ensures that employees are provided a reasonable incentive to achieve exceptional performance levels." 4 Tr 1256.

Responding to the Staff's recommendation to disallow $440,800 for the company's top five officers, Consumers asserted that the company "is contractually prohibited from sharing" information about officer compensation, and argued that in Case No. U-18124, "[t]he Administrative Law Judge upheld Consumers Energy's decision to withhold the same type of information . . . ." 4 Tr 1258. However, Consumers stated that it provided "non-confidential market data using the following compensation elements from the Compensation Peer Group's publicly filed proxy statements: salary, stock awards, and non-equity incentive" to assist the Staff in evaluating the reasonableness of the proposed compensation. 4 Tr 1258; *see*, Exhibit S-16.1. The company also noted that:

> [i]n previous cases, the Company regarded the work performed by the top five officers as focused broadly across the entire CMS Energy enterprise; however, in light of the move to a 30% weighting on Consumers Energy-specific operational measures for EICP, we now have a measurable component of their compensation linked directly to work on behalf of the utility and to operational outcomes that benefit customers.

4 Tr 1260.

Consumers disputed ABATE's claim that between 2018 and 2022, the company only paid out 62% of its budgeted EICP expense. The company contended that "the 5-year average actual-to-target (i.e. budget) percentage is 115%. Actual operational O&M expense was $10.8 million compared to a target of $9.2 million. The $17.5 million referenced [by ABATE] is the maximum payout as illustrated in [Exhibit AB-9, pages 25-26] not the target amount as [ABATE] indicated." 4 Tr 1260.

Although the Staff acknowledged the administrative law judge's determination in Case No. U-18124, the Staff disagreed with Consumers' claim that the determination implies that the company is not required, in this case, to provide the Staff with information regarding officer compensation. The Staff noted that on pages 87-88 of the July 31, 2017 order in Case No. U-18124 (July 31 order), the Commission stated that "[t]o be clear, the Commission expects a more thorough presentation of compensation levels and metrics for the company's employee compensation plans." Staff's initial brief, p. 83.

The ALJ recommended that the Staff's proposed disallowance be approved. She stated that:

> [i]n multiple recent rate cases, the Commission has generally approved recovery of projected EICP costs at the target level for objective measures. Staff's adjustment is not inconsistent with the Commission's prior determinations but is the result of the company's refusal to provide the supporting information it purported to rely on in setting the compensation levels, including EICP levels, for its top five

> executives. This PFD recognizes that the company contracted with a third party with a promise of confidentiality, but this PFD finds that the ostensible purpose for the confidentiality, to protect the intellectual property of the third party, would not be compromised by providing the information under a protective order, and further, that it was the company's choice to rely on supporting information that it had chosen to keep confidential. Had the company wanted to rely only on the additional "public" information that Ms. Conrad subsequently provided in discovery, it should have said so in its direct filing.

PFD, pp. 428-429. The ALJ found Consumers' arguments unpersuasive regarding the administrative law judge's determination in Case No. U-18124, and she noted that the Commission disagreed with a similar argument from Consumers in the March 29, 2018 order in Case No. U-18322. Regarding the Attorney General's and ABATE's recommendations, the ALJ found that they should not be adopted.

In exceptions, Consumers objects to the ALJ's recommendation to disallow $440,800 in EICP expense for the company's top five officers. Consumers reiterates that it does not possess the EICP information for its top five officers and, therefore, cannot share it with the Staff or the Commission. More specifically, the company states that:

> the market information at issue is maintained as part of a database of public utility and general industry compensation survey data owned by Willis Towers Watson. The Company engages Pay Governance to provide the Company's Compensation Committees with information about the market to help guide compensation decisions. Pay Governance (not Consumers Energy) uses the Willis Towers Watson database as part of its consulting function, with permission of Willis Towers Watson and CMS Energy, in order to develop its recommendations.

Consumers' exceptions, pp. 136-137 (internal citations omitted). In addition, the company asserts that even if it could access the information at this point, "it would be a breach of the Company's contract to share it with the Commission." *Id*., p. 137. Consumers argues that it could not rely on publicly available information to develop its EICP expense for the top five officers because Pay Governance has substantial and specialized expertise on market data for senior corporate officer compensation practices that Consumers does not have access to.

The Attorney General also excepts, asserting that the Commission should approve no more than $1.2 million for achievement of operational measures at the lower 50% threshold levels. She contends that "[t]he Company's witnesses have been unable to draw a direct correlation between the performance metrics, incentive compensation, and benefits to Consumer's [sic] electric customers that are at least commensurate with the cost[,] and . . . the Company attempts to quantify alleged customer benefits of certain performance measures included in the EICP but fails in its efforts." Attorney General's exceptions, p. 44 (footnote omitted).

Consumers disputes the Attorney General's claim that the EICP expense should be disallowed because it is likely that the company will not achieve at least the 100% payout level. The company states that "non-officer employees have received incentive payouts as a percentage of target of 112% in 2017, 123% in 2018, 111% in 2019, 139% in 2020, 77% in 2021, and 145% in 2022. History shows that the Company's EICP payout has exceeded the 100% payout threshold almost every year (except one). In fact, the Company's EICP payout in 2023 also exceeded 100%." Consumers' replies to exceptions, pp. 72-73 (internal citation omitted). Consumers reiterates that its EICP expense is modest, below market cost, benefits customers and, therefore, should be approved.

The Commission finds persuasive the ALJ's finding that it is possible to share with the Staff confidential information related to EICP expense through a protective order without disclosing confidential or proprietary information or methods used by the third party. Consumers appears to acknowledge this fact. *See*, Consumers' exceptions, p. 137. In addition, the Commission finds that it was the company's choice to rely on information in a database owned and controlled by a third party. As noted by the ALJ, Consumers could have modified its initial filing to provide projected EICP expense using the public data that the company supplied to the Staff. Given the inability of the Staff to review the information on which Consumers' projected EICP expense for officers is based, the Staff was unable to determine that the company's proposed expense is reasonable. Therefore, the Commission finds that the Staff's proposed EICP expense disallowance for officers should be approved.

Additionally, the Commission finds the Attorney General's arguments persuasive. She contends that the methane emission reduction metric should not be included in the EICP because achieving the target is not within the control of employees of the electric division of Consumers. The Commission agrees and finds that it is not appropriate for the electric division of Consumers to recover costs for a metric whose target may only be achieved by employees in the gas division of the company. Moreover, methane reduction standards were recently proposed by the federal government which Consumers will have to evaluate for potential compliance, let alone exceeding performance targets.[15] Furthermore, the Commission agrees with the Attorney General that Consumers has set an exceedingly low threshold for payout based on operational goals. Specifically, as explained by the Attorney General, "[e]mployees can fail to meet all but one of the operational goals and still qualify for at least some incentive pay as long as [they] reach a 50 percent threshold for that goal." Attorney General's exceptions, p. 45.

The Commission also notes that the "Staff examined the U.S. Energy Information Administration data on IEEE [Institute of Electrical and Electronics Engineers] SAIDI, SAIFI [system average interruption frequency index], and CAIDI [customer average interruption duration index] metrics for all events, which includes major event days, reported by investor-owned utilities [(IOUs)] in the East North Central Census Division which also includes Michigan" and found that

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[15] *See*, Environmental Protection Agency, *Waste Emissions Charge for Petroleum and Natural Gas Systems*, 89 Fed Reg 5318-5381 (January 26, 2024).

"the Company's reliability performance is in the top three worst IOUs in the census division for SAIDI and CAIDI and in the top five worst for SAIFI . . . ." 5 Tr 3756, 3761. The Commission notes that only 5% of Consumers' officer EICP is tied to improving system reliability, whereas 70% is tied to financial goals. *See*, Exhibit A-73, p. 1. The Commission finds that it is unreasonable to approve the company's proposed EICP targets that provide little incentive for Consumers to improve reliability, especially when, in 2021, the company had the third highest SAIDI in the census division and the highest electricity rates compared to its peer IOUs. The Commission notes that from 2020 to 2022, more census tracts were in the fourth quartile of IEEE SAIDI than any other quartile and that these reliability issues have continued into the first quarter of 2023. *See*, 4 Tr 479, 3744-3746.

Similar to the Commission's determination in the December 22 order, the Commission finds that, in this case, Consumers' operational goals are easily achievable and there is little risk that employees will not receive a payout; thus, there is insufficient incentive for employees to appreciably improve operational performance or system reliability to the benefit of customers. Therefore, the Commission finds it reasonable to approve EICP expense that is related to the achievement of operational measures at the 50% threshold. Because the Attorney General's disallowance is set at this 50% threshold, it covers exactly half of the Commission's approved $440,800 disallowance proposed by the Staff and supported by the ALJ. As such, the Commission finds that the company's proposed $2.4 million request for EICP should be reduced by the $1.2 million recommended by the Attorney General plus an additional $220,400 representing the remaining 50% reduction proposed by the Staff for officer EICP expense disallowance, for a total disallowance of $1.42 million. Moreover, the Commission reiterates the conclusion set forth in the December 22 order that "it is necessary for the company's individual operational metrics to be scrutinized more critically and with a higher level of granularity moving forward." December 22 order, p. 298. The Commission again directs Consumers provide more "detailed information connecting its performance in operational metrics to its proposed incentive compensation in its next general electric rate case." *Id*.

12. Demand Response Operations and Maintenance Expense

The ALJ noted that no party opposed Consumers' DR O&M expense and recommended that the Commission approve the company's proposed expense of $35.53 million. *See*, PFD, p. 431.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

13. Uncollectibles and Uncollectibles Expense Tracker

Applying a three-year bad debt loss ratio (BDLR) for 2018, 2019, and 2022, Consumers projected an uncollectibles O&M expense of $17.52 million. *See*, 4 Tr 1360. The company explained that it excluded 2020 and 2021 from its calculation because actions taken by the federal government significantly reduced uncollectibles during those two years. In addition, Consumers proposed "an uncollectible deferral/refund mechanism" that "would allow the Company to defer the difference between uncollectible accounts expense included in rates versus the actual expense recorded by the Company. The Company further proposes that any deferred amounts be considered for collection or refund in a future rate case." 4 Tr 1362. Consumers asserted that the uncollectibles deferral/refund mechanism would create more certainty for the company regarding the amount of funding available to assist customers who are unable to pay their utility bills.

The Staff disagreed with Consumers' proposed calculation of the uncollectibles O&M expense, stating that:

> [t]he Company argues against utilizing consecutive years in the projection citing a lower BDLR. However, excluding years 2020 and 2021 from the projection results

> in a BDLR of 0.385%, higher than the Company has experienced in four years (2018-2021). See Exhibit S-13.1, col. (f). This is contrary to the Company's assertion that its projection provides a reasonable estimate. Additionally, actions taken by the Company have contributed to lowered [uncollectibles expense].

5 Tr 3606. The Staff included the 2020 and 2021 uncollectibles in its calculation and projected a test year uncollectibles O&M expense of $15.04 million. *See*, 5 Tr 3607.

Similarly, the Attorney General asserted that 2020 and 2021 uncollectibles should be included in the expense calculation. She stated that the federal actions cited by Consumers include the American Rescue Plan, "which included expanded unemployment benefits." 4 Tr 3069. In addition, the Attorney General noted that to minimize the impact of the COVID-19 pandemic, Consumers "suspended past due bill dunning which would have the opposite effect of increasing past due amounts and uncollectible accounts expense. Moreover, the expanded unemployment benefits were provided to individuals out of work due to the pandemic as a substitute for the paychecks they would have normally received." 4 Tr 3069. Furthermore, she contended that the greatest amount of assistance was provided to customers in 2022, which is one of the years in Consumers' BDLR calculation; thus, the Attorney General asserted that "the Company's explanation of excluding net charge-offs for 2020 and 2021 from the BDLR average does not fit the facts." 4 Tr 3070. She recommended that the Commission use the three most recent years for the BDLR, which results in a projected test year uncollectibles O&M expense of $14.9 million. *See*, 4 Tr 3070.

In response to the Staff, Consumers asserted that the "reduction in BDLR in 2020 and 2021" is "anomalous and not representative of the Company's historic [sic] uncollectibles expense amount." 4 Tr 1376. Additionally, the company argued that the Attorney General used an incorrect uncollectibles expense calculation. Consumers stated that:

> [t]he correct calculation would be to use a three-year average of the annual net energy write-offs and three-year average electric service revenue to calculate the BDLR. The 2020, 2021, and 2022 three-year average write-offs is $14,912,000 and the average revenue for those years is $4,522,206,000, resulting in a BDLR of 0.330%. This correction to the calculation would result in a revised test year uncollectible accounts expense of $15,023,000, an increase of $148,000 from [the Attorney General]'s calculation of $14,875,000.

4 Tr 1377. Moreover, the company disputed the Attorney General's claim that Consumers inappropriately excluded 2020 and 2021 uncollectibles when a greater amount of assistance was provided to customers in 2022. Consumers contended that many COVID-19 pandemic protections and supplemental assistance ended in 2022 and, as a result, customers applied for more traditional forms of assistance through the company.

Regarding Consumers' proposed uncollectibles deferral/refund mechanism, the Staff argued that the mechanism:

> disincentivizes the Company from continually striving to reduce uncollectible expense below the amount set in rates. If approved, customers may receive a short-term gain in the form of a refund should the expense be lower than the amount set in rates. However, there is no incentive for the Company to put forth its best efforts to lower bad debt expense below the amount set in rates with a tracker in place.

5 Tr 3608.

MNSC asserted that if the uncollectibles deferral/refund mechanism is approved, it should be modified to be "a one-way tracker that would defer a regulatory liability if uncollectible expenses are lower than expected." 4 Tr 2653.

The ALJ found that the method for calculating projected uncollectibles expense provided by the Staff and Consumers is reasonable because it is consistent with the Commission-approved method. However, the ALJ stated that she "agrees with Staff and the Attorney General that Consumers['] omission of the years 2020 and 2021 in its calculation of this expense was inappropriate. Although uncollectible expense was reduced to some extent in 2020 and 2021, the use of a multi-year average will smooth that variation." PFD, p. 434. The ALJ recommended that the Commission reduce Consumers' projected uncollectibles expense by $2.48 million, as calculated by the Staff. In addition, the ALJ stated that she "also agrees with Staff that an uncollectible expense tracker is unsupported and unnecessary and that the implementation of such a mechanism could reduce the company's incentive to collect on past due accounts." *Id.*, p. 435.

In exceptions, Consumers objects to the ALJ's recommendation to use a three-year average of BDLR that includes 2020 and 2021. The company states that the Staff's and the Attorney General's proposed "three-year average will not smooth the effects of the COVID-19 pandemic which skewed the [BDLR] . . . ." Consumers' exceptions, p. 139. Consumers reiterates that the anomalies in 2020 and 2021 are not representative of the company's historical uncollectibles amount and will distort the projected uncollectibles expense.

Additionally, Consumers disputes the ALJ's finding that the uncollectibles deferral/refund mechanism should be rejected because it will disincentivize the company to reduce its uncollectibles expense. The company states that it will continue to make efforts to reduce its uncollectibles expense and notes that it "has also already implemented several mitigation strategies to manage the uncollectible accounts expense, including requiring customers to pay any unpaid balance in full prior to opening a new utility account and prioritizing collection activities on high risk and high volume past due accounts." Consumers' exceptions, pp. 139-140 (citing 4 Tr 1362).

MNSC responds that "Consumers provides no compelling reason to reject the PFD's recommendation. The company asserts that it will undertake efforts to control uncollectible expense but does not address the undeniable fact that it will have less incentive to do so with a tracker." MNSC's replies to exceptions, p. 22. MNSC avers that the uncollectibles expense deferral/refund mechanism will transfer the risk of uncollectibles to customers.

The Attorney General "disagrees that the pandemic related assistance justifies omitting 2020 and 2021 from calculation of the [BDLR]" for the reasons set forth in her testimony and briefing. Attorney General's replies to exceptions, p. 83.

The Commission finds that the ALJ's recommendation is reasonable and prudent and should be adopted. As noted by the ALJ, the Commission has a long-standing practice of adopting the most recent three-year average BDLR. *See*, December 22 order, p. 292; December 17, 2020 order in Case No. U-20697, p. 204; March 29, 2018 order in Case No. U-18322, p. 47. In addition, the Commission finds persuasive the Staff's assertion that "excluding years 2020 and 2021 from the projection results in a BDLR of 0.385%, higher than the Company has experienced in four years (2018-2021)." 5 Tr 3606. Furthermore, the Commission agrees with the ALJ that the multi-year average will smooth the variations that occurred in 2020 and 2021. Thus, the Commission finds that the Staff's BDLR should be approved.

Regarding the uncollectibles expense deferral/refund mechanism, the Commission finds that the ALJ's recommendation should be adopted. The Commission finds that the three-year average BDLR that is used in Consumers' frequent annual rate case filings adequately captures any volatility in yearly uncollectibles, which negates the need for a deferral/refund mechanism. *See*, 5 Tr 3607. In addition, the Commission agrees with the Staff that "[t]he Company is in partial control of bad debt expense" because Consumers can (and has) implemented mitigation strategies to manage uncollectibles. *See*, 4 Tr 1362. Finally, the Commission agrees with the Staff and the ALJ that an uncollectibles deferral/refund mechanism "disincentivizes the Company from continually striving to reduce uncollectible expense below the amount set in rates." 5 Tr 3608. As noted by the Staff, the mechanism allows Consumers to reduce collection efforts because there is a guaranteed deferral of amounts greater than those set in rates. Therefore, Consumers' request for an uncollectibles deferral/refund mechanism is denied.

14. Injuries and Damages Expense

Consumers projected test year injuries and damages O&M expense of $3.98 million. The company explained that this expense "is comprised of three components: electric injuries and damages, internal legal costs, and workers' compensation costs." 4 Tr 1364.

The Staff requested that the Commission approve the company's proposed expense but remove inflation costs of $99,000. The Staff stated that "[a]ll components of the expense vary considerably from year to year. Inflation is not an accurate driver or predictor of future expenses for any component of Injuries & Damages expense." 5 Tr 3893-3894; *see*, Exhibit A-86.

Consumers responded that inflation should be applied to the injuries and damages O&M expense "to account for the rise in pricing of goods and services that are associated with Injuries & Damages expense." 4 Tr 1374.

The ALJ recommended that the Commission approve the Staff's proposed disallowance for inflation. She stated that "[a]s Staff argues, these expenses are the result of unforeseeable accidents, and any year-to-year increase or decrease in costs stems from the number of accidents in a year, not inflation." PFD, p. 436.

Consumers excepts, reiterating that inflation should be included with the five-year average. *See*, Consumers' exceptions, p. 140.

The Commission finds that the ALJ's findings and recommendation are reasonable and prudent and that they should be adopted. As noted by the Staff and the ALJ, injuries and damages expense is the result of unanticipated accidents, and the expense varies depending on the number of incidents, not inflation. Therefore, the Commission finds that the Staff's proposed $99,000 disallowance should be approved.

D. Depreciation and Amortization Expense

The ALJ stated that "[t]he differences among the parties concerning depreciation and amortization expense reflect the differences in plant balances resulting from various adjustments. This amount will be established consistent with the Commission's final order." *Id*.

E. Taxes

1. Property Taxes

Consumers stated that as set forth in Exhibit A-161, the property tax rate for the projected test year is 0.012396326. The company noted that the estimated property taxes for the electric portion of the business is $252.2 million for 2024. *See*, 4 Tr 2337. In addition, Consumers asserted that when plant investment, coal plant valuation tax reduction, property taxes on real property, and the 2024 Mustang Mile investment were included, it resulted in an estimated 2025 property tax amount of $271.4 million for the electric portion of the business. The company contended that it does not "have any ongoing property tax litigation for which it anticipates a refund." 4 Tr 2339.

MNSC expressed concern regarding Consumers' treatment of property tax refunds. MNSC explained that:

> [f]rom time to time, Consumers appeals its local property tax assessments or negotiates the assessments and obtains a refund on its property taxes. When successful in these challenges, Consumers obtains a reduction in taxable value of the subject property going forward and a refund for a portion of what it paid in prior years. In Consumers['] witness Brian VanBlarcum's direct testimony, exhibits, and workpapers, he identifies the tax savings resulting from the reduction in taxable value and makes a corresponding adjustment to tax expense for the test year. However, Consumers does not identify the refund amounts or use those amounts to offset or reduce tax expense. Consumers does not credit the refunds to customers even though customers paid those same taxes in rates during the prior years, and customers fund the costs of the tax challenges through rates as well.

4 Tr 2662. According to MNSC, the company received a total of $82.60 million in refunds from January 2012 through August 2022. MNSC also contended that Consumers has a number of additional cases pending.

Quoting Exhibit MEC-3, MNSC stated that "'to the extent a tax jurisdiction grants, or a court orders, an adjustment applicable to a prior period, Consumers Energy records the activity as an adjustment to tax expense in the year the final adjustment is granted or ordered.'" 4 Tr 2663. In addition, MNSC noted that according to the company, property tax reductions that result from a prior period adjustment are included as a reduction to Consumers' revenue requirement in future rate cases but are not recorded as a regulatory liability. Thus, MNSC contended that it "appears that a change in taxation basis may benefit customers prospectively in rate cases filed after the conclusion of the tax appeal but that neither refunds nor reduced taxes until the conclusion of the next rate case inure to the benefit of customers. It therefore appears that Consumers Energy has gained millions in additional return on equity over the last decade." 4 Tr 2663. MNSC also noted that Consumers received a $1.0 million reduction in property taxes associated with the Campbell and D.E. Karn plants and that it is unclear whether the company received a refund. MNSC recommended that any refunds of local property taxes be credited to tax expense and that "the Commission commence proceedings to 'claw back' previous tax refunds that were unjustly retained by Consumers without being credited to customers." 4 Tr 2665.

Consumers responded that customers have received an estimated $165 million in tax benefits since the conclusion of the tax litigation. In addition, Consumers asserted that the $1.0 million reduction in 2025 property taxes for Campbell and D.E. Karn plants is not a refund; rather, it is a reduction in future taxes. Further, the company disputed MNSC's claim that the company has gained millions in additional ROE over the last decade, stating that MNSC's "analysis fails to consider that portions of the refunds were recorded to regulatory liabilities ($0.9 million), reduced rate base ($36.4 million), or represented a refund of costs that were never charged to customers or included in rates ($11.8 million). These items represent approximately $49 million of the amount refunded to the Company." 4 Tr 2351. Finally, Consumers objected to MNSC's recommendation that the Commission commence proceedings to "claw back" previous tax refunds. The company asserted that MNSC's "recommendation fail[s] to weigh and consider the $165 million estimated tax benefits provided to customers since the conclusion of the above referenced cases, but [MNSC's] recommendation would also constitute retroactive ratemaking." 4 Tr 2351.

In response, MNSC noted that Consumers argued that successful property tax litigation reduces future tax obligations to the benefit of customers. However, MNSC stated that the company admitted that any refunds to Consumers for taxes paid in previous years have not been used to reduce or offset tax expense for customers. *See*, MNSC's initial brief, pp. 35-36. Specifically, MNSC contended that of the $89.48 million in refunds received by Consumers, $49 million was used to reduce the cost of assets or was never charged to customers; but the remaining "$40.5 million in state and local tax refunds that Consumers received" was "never applied as a reduction or offset to tax expense." *Id*., p. 36. In addition, MNSC asserted that customers pay the salaries of Consumers' employees and the fees for the attorneys and appraisers who worked to obtain these refunds. MNSC stated that "the refunds represent property taxes that were overpaid in prior years. Consumers recovered these payments recovered from ratepayers in those years as part of the Company's tax expense for those years." *Id*. Therefore, MNSC requested that those refunds be returned to customers.

Consumers continued to argue that customers have received a benefit from the refunds and that the company is not receiving a windfall by retaining the refunds. The company reiterated that "while some or all of a state or local refund may sometimes be recorded as a credit to property tax expense, other refunds are periodically recorded as a reduction to rate base or to a regulatory liability, and even this treatment may be inappropriate when refunds are for tax expenses that were never charged to customers or included in rates." Consumers' reply brief, p. 57. In addition, Consumers disputed MNSC's claim that the company admitted that refunds are not used to reduce or offset property taxes. Consumers asserted that "refunds have the effect of reducing property taxes in the projected test year." *Id*., p. 58. Finally, in response to MNSC's claim that the company has inappropriately retained tax refunds that were obtained by employees, attorneys, and appraisers paid with ratepayer funds, Consumers stated that "[t]his implies that customers receive no benefits from the refunds, which could not be more wrong. . . . The relatively marginal amount that the Company has paid to secure the refunds pales in comparison to the $165 million benefit customers have received from the refunds." *Id*. (internal citation omitted).

The ALJ found persuasive MNSC's recommendation that the Commission take further action regarding the company's property tax expense. She noted that:

> [u]nder MCL 460.556, the Commission has the power to prescribe uniform methods of keeping accounts for electric utilities. The Michigan Court of Appeals has held that retroactive ratemaking, which is prohibited, involves a change either upward or downward in the rates charged by a utility for its services. Indeed, the Court of Appeals has emphasized that because rates are set in the Commission's legislative capacity, they "must be construed like statutes and only be given prospective effect." Under this principle against retroactive ratemaking, when estimates of future costs on which rates are based prove to be higher or lower than predicted, the previously set rates cannot be changed to correct for the error; the only step that the Commission can take is to prospectively revise rates in an effort to set more appropriate ones.

PFD, pp. 440-441 (footnotes omitted). The ALJ noted that the Commission generally uses deferred tax accounting for state and federal income tax. She also asserted that "[t]he Commission previously determined that deferred tax accounting is not harmful to customers and utilities have even requested that the methodology be used in other cases. The Court of Appeals has upheld the Commission's practice, finding it does not violate the rule against retroactive ratemaking." *Id*., p. 441 (footnotes omitted). The ALJ stated that in accordance with this procedure, "the Commission has required utilities to return or write off deferred taxes to the ratepayers when it was not required to pay the full tax amount recorded in the rate case." *Id*. (footnote omitted).

She stated that Consumers and MNSC agree that since 2012, the company was not required to pay more than $80 million that was collected from ratepayers for property tax expense. The ALJ recommended "that utilities be required to apply deferred accounting principles to property tax in future cases." *Id*. In addition, she asserted that "to better assess the reliability of property tax assessment projections," the Commission should "require utilities to provide a list of pending tax assessment litigation cases as part of rate case filings and an accounting of estimated compared to actual tax assessments for the ten years prior to the rate case filing." *Id*., pp. 441-442.

The ALJ also recommended that MNSC file a formal complaint and that the Commission commence a contested hearing. She noted that Consumers' witness Brian J. VanBlarcum:

> testified in this case that Consumers was refunded $60.45 million after it finalized litigation with the Michigan Department of Treasury, but he provided discovery responses in Case No. U-21224 with a different figure ($63.6 million for tax years 1997- 2015). And in the Michigan Court of Appeals case which resulted in the refund, the Court noted in 2014 that Consumers initiated its protest of the tax assessment in 2010. This PFD concludes that a more in-depth investigation is warranted.

PFD, p. 442 (footnotes omitted).

In exceptions, Consumers contends that MNSC's recommendation to credit future property tax refunds against the company's property tax expense should be rejected because "MNSC's recommendation exceeds the scope of this case, where no refunds are anticipated that could be used as a credit against the property tax expense, and the recommendation ignores the vast benefit that customers have already received from the property tax refunds." Consumers' exceptions, p. 141. The company agrees with the ALJ's recommendation to provide a list of pending tax assessment litigation cases in future rate case filings. However, Consumers objects to the requirement that the company "compare estimated and actual tax assessments 'for the ten years prior to the rate case filing.'" *Id*., p. 142 (quoting the PFD, p. 442). Consumers asserts that this would not be useful in a forward-looking rate case. Finally, the company argues there is no specific authority for the ALJ's suggestion that the Commission use deferred accounting to "claw back" past refunds. Consumers' exceptions, pp. 145-146.

MNSC responds, asserting that "while the PFD does not recommend all of the relief that MNSC sought in this case, the proposals to apply deferred accounting and disclose more property tax information in rate case[s] are reasonable first steps, and MNSC is willing to take up the issue of past retained refunds via a complaint case." MNSC's replies to exceptions, p. 23. MNSC contends that the Commission should adopt these recommendations.

The Commission agrees with the ALJ that utilities should be required to provide a list of pending tax assessment litigation cases and negotiations in their rate case filings, an accounting of estimated compared to actual tax assessments for the 10 years prior to the rate case filing, and records of any proceeds received. As such, in its next general rate case, Consumers shall provide a list of pending tax assessment litigation cases and negotiations, an accounting of estimated compared to actual tax assessments for 10 years prior to the filing, and records of any proceeds received.

The Commission notes that pursuant to the evidence on this record, over the past 10 years, Consumers was not required to pay over $80 million in property taxes that was collected from ratepayers, which results in an average of about $8 million per year. Therefore, the Commission finds that on a going forward basis, Consumers is likely to achieve approximately an $8 million savings in property taxes annually, which may be applied to tax projections in future rate cases.

2. Federal, State, Local Income Tax, and General Tax

The ALJ stated that "[t]he differences among the parties' calculations of federal, state, local, and general tax result from differences in projected revenues and expenses. Staff notes that in rebuttal, the company increased federal income tax (FIT) by $6,548,000 for Solar Production Tax Credits related to the adjustment for Mustang Mile." PFD, p. 442. She noted that the Staff recommended that the Commission adopt the company's adjustment.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

F. Allowance for Funds Used During Construction

The ALJ noted that in rebuttal, Consumers projected an allowance for funds used during construction of $1.79 million, which was equal to the Staff's proposed amount. *See*, PFD, p. 443.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

G. Net Operating Income Summary

Based on the findings above, Consumers' jurisdictional adjusted NOI is $738,994,000.

VII. REVENUE DEFICIENCY

Consistent with the findings and determinations made in this order, the Commission finds that Consumers has a jurisdictional revenue deficiency for the test year of $92,009,000,[16] computed as follows:

Rate Base	$13,669,075,000
Adjusted Net Operating Income	$738,994,000
Overall Rate of Return	5.41%
Required Rate of Return	5.86%
Income Requirements	$801,315,000
Income Deficiency	$62,322,000
Revenue Conversion Factor	1.3391
Revenue Deficiency	$83,453,000
2022 Distribution Deferral	$8,556,000
Revenue Deficiency – Total	$92,009,000

VIII. COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES

A. Cost of Service

Consumers stated that the cost-of-service study (COSS):

> is a three-part analysis that quantifies the utility's cost to serve each rate class. The COSS filed in this case serves two primary purposes. First, it identifies and assigns the utility's electric production and distribution costs to the jurisdictional electric rate classes. Second, the COSS is used to determine the contribution of each

[16] The $92,009,000 revenue deficiency includes $2,979,000 for the IRM surcharge. Accordingly, $88,030,000 will be collected through base rates and $2,979,000 will be collected through the IRM surcharge.

> jurisdictional electric rate class to jurisdictional earnings. Ultimately the information provided by the COSS is used to guide rate design among other things. The fundamental guiding principle used to assign costs in the COSS is cost causation. In other words, the costs assigned to a class or group of customers should reflect how those customers drive or influence the utility's costs.

4 Tr 1310.

Consumers provided two versions of the COSS. The company explained that in Version 1 of the COSS, Consumers included routine updates for historical and test year data and incorporated changes approved in the January 19 and December 22 orders. For Version 2 of the COSS, the company began with Version 1 of the COSS but incorporated four proposals that were included in the COSS for Case No. U-21224:

> (i) breakout and allocation of battery plant and related costs; (ii) breakout and allocation of PMD [PowerMI Drive] and PMF [PowerMI Fleet] regulatory asset and amortization expense; (iii) centralization and calculation of Rate EIP [Energy Intensive Primary] interruptible credits in Rate Design; and (iv) use of the alternative Class Peak calculation (e.g., Alternative Class Peak) to allocate demand-related distribution plant and related costs.

4 Tr 1309. Consumers requested that the Commission approve Version 2 of the COSS.

1. Battery Plant Cost Treatment

The ALJ noted that according to the company, "as battery plant investments increase, the company proposes to break out battery plant and related costs as part of the COSS. Consumers notes that no party objected to this change to the COSS, which should be approved." PFD, p. 444 (footnote omitted).

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

2. PowerMIDrive and PowerMIFleet Regulatory Asset and Amortization

Consumers proposed breaking out the regulatory asset and amortization expense for both PMD and PMF and allocating PMD costs to the residential class and PMF costs to the commercial secondary and primary (C&P) rate classes. Consumers stated that "[b]ecause there are multiple C&P classes in the COSS, the Company is proposing to allocate PMF costs to C&P classes using the count of customers in those classes (Allocator 17 267: Customers- Commercial & Primary). The Company's proposed allocation of these costs is a better reflection of how customers use and benefit from both programs." 4 Tr 1321.

Although the Staff agreed with Consumers that the cost "allocation should reflect the benefits received by ratepayers from the pilots," the Staff contended that the company's proposed Version 2 of the COSS "accomplishes this goal." 5 Tr 4031. The Staff explained that:

> the manner in which the pilots exert downward rate pressure is through spreading the costs the Company incurs that do not vary with usage on a higher amount of usage, thereby lowering rates. As these costs are allocated to all classes, the benefit of them being spread over more usage accrues to all classes in proportion to the responsibility for those costs.

5 Tr 4031. Therefore, the Staff recommended that the costs be allocated on overall revenue requirement (for distribution and power supply separately) because it best represents the benefit from the downward rate pressure. The Staff also objected to using customer count to allocate cost among commercial and industrial (C&I) customers because it "does not reflect the manner in which the benefits accrue" and "is unsupported." 5 Tr 4032.

Consumers disagreed with the Staff's proposal to allocate costs based on the overall revenue requirement. The company stated that "the total allocated revenue requirement is the final result from the COSS that depends on the allocators contained therein. Using an allocator derived from each rate class's share of the revenue requirement will affect their share of the revenue requirement which will change the allocator." 4 Tr 1341. In addition, Consumers disputed the Staff's claim that the revenue requirement allocator best represents the benefit from downward rate pressure. The company asserted that the "Staff's proposal, which assumes all customers benefit in proportion to their overall allocation of costs, results in residential customers paying for PMF costs and commercial and primary customers paying for PMD costs," which the company deems inappropriate. 4 Tr 1341.

ABATE also disagreed with the Staff's proposal. According to ABATE:

> [t]he costs associated with these pilots will be the investment in the necessary infrastructure to allow for charging equipment to be connected safely and reliably to the grid and the rebates that the program pays out to customers. These costs will necessarily be driven by customer preferences to be involved in the program, with no regard to the overall revenue requirement of those customer classes. [The Staff] has failed to justify how or why the overall revenue requirement would drive costs of this program and [the] proposal should be rejected.

4 Tr 2794. ABATE argued that the Staff's proposal would shift approximately $738,000 of costs from the residential class to all other classes and the C&P class would receive the majority of the costs, which is contrary to cost causation principles and is inequitable. *See*, ABATE's initial brief, p. 67. ABATE recommended approving Consumers' proposed cost allocation.

In response, the Staff asserted that "[t]hese claims fail to recognize that the justification for the program being funded by ratepayers is the downward rate pressure exerted, which accrues to all customers, making the cost incurrence by class a less appropriate method for allocation than Staff's proposal to utilize the benefits." Staff's reply brief, p. 35.

The ALJ agreed with the Staff and recommended that the Commission adopt the Staff's cost allocation method. However, she stated that "present revenues, rather than projected revenues, should be used in the calculation of the cost allocation to eliminate the circularity problem identified by the company. This recommendation to mitigate the circularity issue has been previously proposed and approved in relation to the same issue that was raised in DTE Electric's most recent rate case." PFD, p. 447.

Consumers agrees with the ALJ that using the allocation of present revenue solves the circularity problem. However, the company objects to the ALJ's recommendation to adopt the Staff's proposal because it "suffers from the defect that it causes residential customers and commercial and industrial customers to pay costs that were meant to benefit the other group." Consumers' exceptions, p. 158. Accordingly, the company requests that the Commission approve Consumers' original allocation proposal. However, if the Commission adopts the ALJ's recommendation, the company asserts that the Commission should make the adjustment proposed in the PFD and requests that "the Commission clarify what functional and allocation factors the Company should apply in the future so that there is no confusion." *Id*., p. 159.

In exceptions, ABATE objects to the ALJ's recommendation. ABATE contends that "[b]ecause this allocation does not reflect cost causation[,] the Commission should instead ensure that the costs associated with the PMD residential pilot should be allocated to the residential class while costs associated with the PMF commercial pilot should be allocated to commercial secondary and primary classes based upon customer counts." ABATE's exceptions, p. 12.

In response to Consumers' and ABATE's claim that the Staff's proposed allocation does not reflect cost causation, the Staff states that "[w]hat these positions continue to fail to recognize is that the programs costs are only included in rates due to the expectation of the additional exerting downward pressure on all rates, and thus that is the manner in which the costs are caused . . . ." Staff's replies to exceptions, p. 29. The Staff asserts that the ALJ's recommendation is supported by evidence on the record and should be adopted.

The Commission finds that the ALJ's findings and recommendation are reasonable and prudent and should be adopted. Consumers and ABATE claim that the costs related to PMD should be allocated to the residential class and the costs related to PMF should be allocated to the

C&P class because this allocation best represents the benefits of these programs. Although the Staff agrees that the "allocation should reflect the benefits received by ratepayers from the pilots," the Staff argues that Consumers' and ABATE's proposal does not accomplish this goal. The Staff explains that:

> [w]hile [Consumers] claims the benefit will be a downward pressure on rates as a result of the increased revenue within the class from which that revenue is produced, that is not an accurate description of the benefit. Those additional revenues resulting from increased usage will be offset by the additional allocation of costs to those classes. In Staff's opinion, the manner in which the pilots exert downward rate pressure is through spreading the costs the Company incurs that do not vary with usage on a higher amount of usage, thereby lowering rates. As these costs are allocated to all classes, the benefit of them being spread over more usage accrues to all classes in proportion to the responsibility for those costs. Additionally, the proposal to use customer count to allocate amongst C&I customers does not reflect the manner in which the benefits accrue, is unsupported, and should also be rejected.

5 Tr 4031-4032 (footnote omitted). Accordingly, the Commission finds that the Staff provided sufficient support and justification for allocating the costs on overall revenue requirement (for distribution and power supply separately) and, thus, the Staff's proposal should be adopted.

In addition, the Commission adopts the ALJ's recommendation to use the allocation of present revenue. Consumers requested that if the Commission adopted the ALJ's recommendation, "the Commission [should] clarify what functional and allocation factors the Company should apply in the future," and the company suggested "Functional Factor 'Rev' (Present Revenue), and using Allocators 141: Production Present Revenue, 142: Distribution Present Revenue, and 143: Total Present Revenue as appropriate for the relevant cost." Consumers' exceptions, pp. 158-159. The Commission finds that Consumers' request is reasonable and prudent and that it should be approved.

3. Energy Intensive Primary Interruptible Credits

Consumers noted that in Case No. U-21224, the company proposed to simplify the process for providing Rate EIP customers with a credit for interruption of service during a critical peak event. The company explained that this simplified process involved removing the adjustment from the COSS and, instead, including it in rate design. Consumers stated that this "proposal is reflected in current rates. The Company is proposing to continue this treatment in the current case." 4 Tr 1322-1323. In addition, Consumers proposed that the interruptible credit for Rate EIP customers be gradually lowered and that it be displayed as a separate line item on the customer's bill. *See*, Consumers' initial brief, p. 422. The ALJ noted that no party opposed these proposals and recommended Commission approval of the proposals. *See*, PFD, pp. 447, 448.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

Next, Consumers argued that "[t]o make the EIP credit commensurate with the interruptible credit provided to other interruptible customers, the Company proposes to gradually lower the credit by 10% to 115% of CONE [cost of new entry], and over five rate cases, the Company would ultimately lower the credit to 75% of CONE." Consumers' initial brief, p. 422. According to the company, reducing the credit to 75% of CONE would approximately double the overall percent increase for Rate EIP customers.

The Staff did not dispute Consumers' proposal to align the EIP credit with the credit offered to other interruptible customers, but it objected to the company's proposal to reduce the credit over the next five rate cases. The Staff recommended "accelerating the time period over which the equalization should occur. Specifically, Staff recommends setting Rate EIP's DR credit to 100% of CONE in the instant case, and further reducing the credit to 75% of CONE in the Company's next general rate case." Staff's initial brief, p. 178 (citation omitted). The Staff explained that this will help balance the effect of the credit on the few Rate EIP customers and all other customers. Finally, in response to Consumers' claim that reducing the credit to 75% of CONE would approximately double the rate impact for Rate EIP customers, the Staff stated that the "Staff's revenue requirement is materially lower than the Company's, so the rate impact of reducing the DR credit is therefore also lessened, allowing for a shorter alignment time period." 5 Tr 3670.

ABATE disagreed with the Staff's claim that its reduced revenue requirement will decrease the impact to the Rate EIP credit. By contrast, ABATE asserted:

> Rate EIP would receive an 8.8% increase under Staff's proposed Power Supply revenue requirement, while the Primary class as a whole on average would receive a 2.6% <u>decrease</u>, and the total Power Supply revenue requirement is <u>decreasing</u> by 5.3%. This is a clear indication that the Staff's revenue requirement reduction is not substantial enough to warrant the accelerated reduction of Rate EIP's interruptible credit.

4 Tr 2790 (emphasis in original) (footnote omitted). Consumers agreed. *See*, Consumers' initial brief, p. 423.

In addition, Consumers stated that the company disagrees with the Staff's revenue requirement determination. Consumers argued that even if the company's revenue deficiency was used instead, "the reduction proposed by Staff would add 23% to rate EIP's revenue increase." *Id*.

Responding to ABATE, the Staff acknowledges that:

> Staff's rate design, including the Rate EIP DR credit equal to 100% of CONE, results in an increase of 8.8% in power supply revenue requirement for Rate EIP. This revenue requirement increase is reasonable and not out of the ordinary for a typical rate case request. Any decrease in the credit received by Rate EIP customers reduces the revenue requirement of all other power supply customers one-to-one.

Staff's initial brief, p. 178 (internal citation omitted). The Staff asserted that Consumers' DR portfolio is one of the most expensive in the country and reducing the overpayment to Rate EIP customers will assist in bringing the cost, which is paid by all power supply customers, to a more reasonable level.

The ALJ found the Staff's position on this issue to be persuasive. She noted that "[t]he parties agree that the interruptible credit for EIP customers is considerably higher than other DR credits and should be reduced." PFD, p. 451. Although Consumers and ABATE argued that the Staff's proposed accelerated timeline for the reduction is burdensome on Rate EIP customers, the ALJ stated that the current EIP credit is unreasonably burdensome to all customers. She recommended that "the Commission reduce the interruptible EIP credit to 100% of CONE in this case and approve a reduction to 75% of CONE in Consumers' next general rate case." *Id*., pp. 451-452.

In exceptions, Consumers objects to the ALJ's recommended reduction. Consumers states that "the Commission should approve the Company's proposed gradual reduction in the credit to reasonably move Rate EIP customers closer to a cost-based credit without the undue burden of an accelerated decline in the credit." Consumers' exceptions, p. 162 (citing 3 Tr 218).

ABATE also excepts, asserting that the Commission should adopt a more gradual approach to reducing the credit because the Staff's proposal will create an unreasonable burden for Rate EIP customers. ABATE states that "the Commission should approve Consumers' proposal to base the credit on 115% of CONE in this case, with reduction to 75% of CONE to occur over five rate cases." ABATE's exceptions, p. 11.

The Staff disputes Consumers' and ABATE's claim that reducing the Rate EIP credit would cause rate shock. The Staff states that it:

> showed that its proposal to reduce the credit more rapidly would not cause rate shock assuming the Commission approves of Staff's significantly lower revenue requirement. (Staff's Initial Brief, p 178.) Staff now points out that the PDF's [sic] revenue requirement was even lower than Staff's proposal, so it stands to reason that the impact of reducing Rate EIP's interruptible credit will have an even lesser impact on customers.

Staff's replies to exceptions, p. 25. Accordingly, the Staff requests that the Commission approve its proposal to reduce the Rate EIP credit by the end of Consumers' next rate case.

The Commission finds that the ALJ's findings and recommendation are reasonable and prudent and should be adopted. As noted by the ALJ, the parties agree that the interruptible credit for Rate EIP customers is significantly higher than other credits and should be reduced. Specifically, the Staff explains that Consumers' "DR portfolio is already one of the most expensive in the country" and that the current EIP credit is burdensome to all customers. Staff's initial brief, p. 179. Reducing the credit, which is paid by all power supply customers, will assist in bringing the cost of the credit to a more reasonable level. Although Consumers and ABATE argue that Staff's proposed abbreviated timeline for reducing the credit will cause rate shock, the Commission finds the Staff's position persuasive that the "revenue requirement increase is reasonable and not out of the ordinary for a typical rate case request. Any decrease in the credit received by Rate EIP customers reduces the revenue requirement of all other power supply customers one-to-one." *Id*., p. 178. Therefore, the Commission finds that the Staff's proposal to set the Rate EIP DR credit to 100% of CONE in this case and to reduce the credit to 75% of CONE in Consumers' next general rate case should be approved.

4. Alternative Class Peak

The ALJ noted that Consumers proposed "to change the Class Peak allocator for demand-related distribution plant costs with the Alternative Class Peak allocator in its COSS Version 2" and that no party opposed this change. She recommended that Consumers' proposal be approved. PFD, p. 452.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

5. Substation Ownership Credit Calculation

The ALJ noted that no party objected to Consumers' proposal "to continue the allocation of substation ownership credits in accordance with the method approved in Case No. U-18322" and, therefore, she recommended that it be adopted. PFD, p. 452.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

6. Allocation of Surcharges

The ALJ stated that "[a]lthough there was dispute over certain programs associated with proposed surcharges, as discussed elsewhere in this PFD, the company's proposed allocation of DR, Electric Rate Case Deferral, and IRM surcharges was not opposed." *Id*.

No exceptions were filed on this issue. The Commission finds the ALJ's findings and recommendations reasonable and prudent and that they should be adopted.

7. The Commission Staff and Intervenor Recommendations

a. The Commission Staff

The Staff stated that Consumers:

> should be required to continue to account for and allocate clearly attributable customer-related costs to the classes responsible. Even though the Company testifies that there are no costs in this case specifically attributable to the [C&I] Online Account Management project, in future rate cases there could be DCO [digital customer operations] projects that would need to be broken out in the COSS to properly allocate these costs. In addition, in the instant case, there are costs amounting to approximately $0.4 million associated with the Move In/Move Out 3.0 and Move In/Move Out Energy Efficiency (MIMO EE/3.0) projects that primarily serve residential customers. These costs need to be broken out in the COSS to allocate these costs solely to the residential class instead of putting them in General, Common, and Intangible plant which would allocate them to all customers based on labor. Even if the amount attributed to these projects is small in comparison to other costs, it is important to have as much accuracy as possible when assigning costs to the customer classes. For these reasons, the Company should continue to break out DCO costs in the COSS in future rate cases. This will

> help to ensure that DCO costs are being assigned to the classes which are causing them.

5 Tr 3719.

Consumers responded that while accuracy is a reasonable objective, it should be considered in the context of the benefit and cost of providing such detail. The company explained that "[t]he COSS is responsible for allocating over $5.3 billion and the revenue requirement associated with the project at issue (MIMO 3.0/EE) is about $0.4 million. The impact on any given rate class from changing the allocation of this project is at or less than 0.01%." 4 Tr 1340. Consumers stated that considering the billions of dollars that are reviewed and allocated in the COSS, it is not practicable to break out every project. The company asserted that "[w]hile it could be argued that this specific request only involves 2-3 projects, the Company is concerned that this type of precedent raises questions as to why some smaller projects are broken out in the COSS and not others." 4 Tr 1340.

The ALJ found persuasive the Staff's argument, stating that "the company did not demonstrate that there are additional costs associated with breaking out and assigning DCO project costs with more precision." PFD, p. 454. She recommended that the Commission direct Consumers to continue to account for and allocate customer-related costs to the classes responsible for the costs.

In exceptions, Consumers reiterates that breaking out and assigning DCO project costs is infeasible, complex, burdensome, and potentially unmanageable. *See*, Consumers' exceptions, pp. 160-161.

The Staff responds, arguing that Consumers simply reiterates the arguments that were considered and rejected by the ALJ. The Staff states that the ALJ "properly considered the record evidence and correctly recommended that DCO costs continue to be broken out in the Company's COSS." Staff's replies to exceptions, p. 27 (citation omitted).

Although Consumers claimed that breaking out DCO project costs is infeasible, complex, burdensome and unmanageable, the Commission notes that the company acknowledged that "accuracy is a reasonable objective." Consumers' exceptions, p. 160 (quoting 4 Tr 1339). In addition, as noted by the ALJ, Consumers "did not demonstrate that there are additional costs associated with breaking out and assigning DCO project costs with more precision." PFD, p. 454. Therefore, the Commission finds that the Staff's proposal should be approved.

The Staff also noted that for the test year projections in the COSS, Consumers uses historical ratios, and in this case, the company used 2021 historical amounts. The Staff stated that, "[f]or example, for Production O&M, for Capacity Related Operations the Company starts with a lump generation O&M amount of $164,252 and multiplies it by the 2021 historical ratio of Capacity Related Operations to the Total Fossil O&M," which "results in 25% or $41,677 of the initial $164,252 being projected to Capacity Related Operations in the test-year." 5 Tr 3711. According to the Staff, the historical composition of Production O&M expense is used as an allocator for the total test year Production O&M expense. However, the Staff contended that Consumers is aware that the projected test year amount will not change for some accounts. The Staff stated that, for these accounts, "the test-year projection is set equal to the 2021 historical amount and the other accounts in that COSS category are allocated the remaining total lump projection amount based on historical ratios." 5 Tr 3712.

The Staff argued that this method fails to capture an accurate projection of test year costs and amounts for the COSS accounts because it "creates a disconnect between cost recovery and cost causation." 5 Tr 3712. The Staff recommended that for future test year COSS projections, Consumers should be directed to provide projected test year spending in the exact, or as close to exact as possible, accounts or COSS categories in which it will be recorded, rather than historical spending. Specifically, the Staff requested that "the Commission require the Company to file a more comprehensive COSS in its next case that includes the direct impact of proposed spending in the appropriate COSS accounts or categories, rather than relying on historic spending ratios." 5 Tr 3712-3713.

Consumers disagreed, asserting that the company's method for allocating costs has been approved by the Commission for the last 15 years. In addition, the company contended that:

> [f]or the witness to provide a breakout of costs by FERC account and voltage level would require the Company to completely revamp how it develops investment plans and even then, would still rely on allocations. This would be a massive undertaking - in a given case there can be thousands of different projects where each project/program can contain multiple types of costs that would be categorized in numerous FERC accounts. The Company has not prepared an estimate of the time or cost that would be necessary to make such a comprehensive change to its planning and forecasting process, but the Company believes it would be significant.

4 Tr 1337. Consumers argued that it does not have advanced knowledge of exact costs, equipment type, or voltage level until shortly before the work is performed; thus, the company must rely on historical costs and expected growth. Consumers asserted that "[i]t would not be possible for the Company to accurately assign FERC and voltage level detail to these categories." 4 Tr 1337-1338.

In response, the Staff stated that "the only way to get evidence of measurable benefit for this recommendation is for the Company to make the necessary test-year projections in the precise COSS accounts and then calculate the difference between the current method using historical ratios. Only the Company has the data necessary to perform this analysis along with time requirements analysis and cost analysis." Staff's initial brief, p. 103.

Consumers disputed the Staff's claim, asserting that it does not have the necessary data. The company contended that "to get the data necessary to even perform this analysis, the Company would need to plan and budget its project costs on a [FERC] account or voltage level basis. But, Ms. Davis explained that 'the Company does not plan or budget project costs on a FERC account or voltage level basis.'" Consumers' reply brief, p. 64 (quoting 4 Tr 1336). Consumers reiterated that the Staff's proposal would be "a massive undertaking" for something the "Staff believes *might* be better for the COSS model." Consumers' reply brief, pp. 64-65 (quoting, 4 Tr 1337).

The ALJ stated that "[a]lthough tacitly highlighting another problem presented by the use of a projected test year, for the reasons set forth in Consumers['] brief and reply brief, this PFD finds that Staff's recommendation should be rejected." PFD, p. 457.

The Commission finds that the ALJ's findings and recommendation are reasonable and prudent and should be adopted. The Commission takes note of the Staff's concern regarding Consumers' method for making test-year projections in the COSS for certain accounts based on historical amounts because it creates a disconnect between cost recovery and cost causation. According to the Staff, this method "potentially results in subsidizations among the customer classes." 5 Tr 3712. However, Consumers argues that the Staff provided "no evidence (or even consideration) of (i) whether the recommendation is feasible, (ii) whether it would provide any measurable benefit, (iii) how much time and effort it would require, or (iv) at what cost." Consumers' initial brief, p. 412 (citation omitted). Although the Commission agrees with the ALJ that the Staff's position on this issue "tacitly highlight[s] another problem presented by the use of a projected test year," the Commission finds Consumers' arguments, at this time, to be persuasive.

b. Michigan Municipal Association for Utility Issues Recommendations

i. Uncollectible Cost Allocation to Streetlighting Customers

The ALJ noted that Consumers did not propose any changes to its Commission-approved practice of allocating uncollectibles expense based on total revenue. She stated that, "[n]otably, in Case Nos. U-20940 and U-20836, the Commission determined that because no customer is responsible for another customer's bill, uncollectible costs should be considered a general cost of doing business." PFD, p. 457 (footnote omitted).

Consumers proposed to allocate $157,000 of uncollectibles expense to streetlighting customers.

MI-MAUI asserted that pursuant to the discovery response in Exhibit MAU-6, streetlighting customers do not cause any uncollectibles expense. Rather, MI-MAUI stated that "streetlight customers are unlike every other customer class in that they have historically *always* paid their streetlight bills." 4 Tr 3160 (emphasis in original). MI-MAUI contended that streetlighting customers should not be responsible for the uncollectibles expense.

In response, Consumers disputed MI-MAUI's claim that streetlighting customers do not contribute to uncollectibles expense. The company argued that it "has recorded uncollectible amounts (net write offs) associated with streetlighting rates/customers over the last number of years. [MI-MAUI] cites a discovery response that the Company has no record of repossessing streetlights from customers with unpaid bills, but that does not mean streetlighting customers have had no write offs." 4 Tr 1343.

The Staff asserted that it supports the method approved in the December 9, 2021 order in Case No. U-20940. Specifically, the Staff explained that:

> as a general cost of business, uncollectibles should not be attributed to the classes in the manner suggested [by MI-MAUI]. As stated by the Commission in a similar decision: "[t]he Commission agrees with the Staff that allocation on a general basis, such as total revenue, is most appropriate and aligns best with ratemaking principles." Because no customer is responsible for another's bill, uncollectibles are a general cost of doing business, and the amount of previous uncollectibles within a class does not matter with regard to the appropriate allocation. Therefore, MI-MAUI witness Bunch's proposal that streetlighting customers not be allocated uncollectibles should be rejected.

5 Tr 4048-4049 (quoting November 18 order, p. 385) (footnote omitted).

The ALJ noted that in the December 1 order, the Commission rejected a similar argument from MI-MAUI. She stated that "with no evidence of a legal error or other reason to disturb the Commission's prior rationale and findings on this issue, this PFD rejects MAUI's recommendation." PFD, p. 458.

In exceptions, MI-MAUI objects to the ALJ's recommendation stating that "[t]he continued application of the allocation method approved in prior decisions to the streetlighting class does not comport with the statutory requirement for the Commission [to] ensure reasonable rates that are 'equal to the cost of providing service to each customer class.'" MI-MAUI's exceptions, p. 4 (quoting MCL 460.11(1)). MI-MAUI asserts that the Staff's proposed method that was approved in the December 1 order does not align uncollectibles with cost causation and should be rejected.

Consumers replies that the Commission properly rejected MI-MAUI's proposal in the December 1 order, and for the same reasons set forth in the December 1 order, the Commission should reject MI-MAUI's proposal in this case. In addition, the company disputes MI-MAUI's claim that the allocation method approved in the December 1 order is contrary to statutory requirements. Rather, Consumers states that, because "uncollectible expense is a general cost of doing business . . . there is nothing inconsistent about assigning a portion of all general costs of doing business to all customer classes because they all generally do business with the utility." Consumers' replies to exceptions, p. 113. Furthermore, the company objects to MI-MAUI's recommendation that streetlighting customers be exempt from allocation of uncollectibles expense. Consumers explains that MI-MAUI's proposal is "unlawful because it calls for the Commission to deny rate recovery for a portion of a cost that is otherwise admitted to be one the Company reasonably incurred to provide utility service." *Id*., pp. 113-114.

The Staff asserts that, in exceptions, MI-MAUI reiterates the arguments that were considered and rejected by the ALJ. The Staff states that "[t]he ALJ properly considered that evidence, along with the evidence presented by Staff" and found that MI-MAUI's proposal should be denied. Staff's replies to exceptions, pp. 27-28. The Staff requests that the Commission adopt the ALJ's recommendation.

The Commission notes that MI-MAUI's argument is substantially the same as that presented by MI-MAUI in Case No. U-21297, which was rejected by the Commission. Similarly, in this case, the Commission finds that the inability of one member of a class to pay a utility bill is only attributable to an individual customer and not an entire class. Thus, uncollectibles should not be allocated to a particular customer class. In addition, the Commission finds that past uncollectibles amounts (or lack thereof) are not relevant to cost allocations going forward. The Commission reiterates that uncollectibles expense is a general cost of doing business to be shared by all customers. Therefore, as stated by the ALJ, "with no evidence of a legal error or other reason to disturb the Commission's prior rationale and findings on this issue," the Commission finds that the ALJ's recommendation should be adopted and that MI-MAUI's proposal should be denied. PFD, p. 458; *see*, December 9, 2021 order in Case No. U-20940, pp. 189-190.

ii. Distribution Cost Allocation to Streetlighting

MI-MAUI asserted that Consumers allocates a share of primary and secondary distribution costs and allocates all of the costs of assets on dedicated streetlight circuits to streetlighting customers. MI-MAUI objected to this allocation method, stating that:

> due to streetlighting's unique use of the distribution system, the proposed class peak allocator does not fairly represent the streetlighting class's use of the grid. Specifically, streetlighting as a class differs from other classes in its causation of grid costs in the following three ways: (1) the streetlighting class causes less wear and tear on the distribution system than other classes because it uses electricity when other classes are at their lowest demand, (2) the streetlighting class does not

> cause geographic growth on the secondary distribution system, and (3) the streetlighting class does not cause capacity growth on the secondary distribution system.

MI-MAUI's initial brief, p. 17 (citing 4 Tr 3152-3153). MI-MAUI proposed that streetlighting customers should be allocated primary distribution system costs and that they pay their portion of O&M, but that they be allocated no secondary distribution capital expenses. Accordingly, MI-MAUI recommended that the Commission reduce the amount of secondary distribution capital costs allocated to streetlighting customers by $11.1 million and reallocate this amount to other classes. *See*, MI-MAUI's initial brief, p. 19.

Consumers disagreed with MI-MAUI's claim that streetlighting customers provide most of their own distribution system and, therefore, they should pay nothing for secondary distribution capital costs. The company stated that although the cost of dedicated streetlighting infrastructure is captured in FERC account 373, streetlighting customers use the upstream facilities that are connected to and bring electricity to that infrastructure. Specifically, Consumers asserted that "streetlighting customers receive service from the same Voltage 4 facilities that serve non-streetlighting customers and the Company does not normally build separate circuits to serve its streetlighting customers." 4 Tr 1345, 2072, 2299.

ABATE also objected to MI-MAUI's proposal to remove the allocation of secondary distribution plant in service from FERC accounts 360-369 for streetlighting customers. ABATE stated there are two reasons why MI-MAUI's proposal should be rejected: (1) "the streetlighting class requires distribution plant contained in FERC Accounts 360-369 in order to receive electric service from Consumers; therefore, they should be allocated costs associated with this equipment," and (2) MI-MAUI's "recommendation would remove the allocation of all of the HVD and Primary distribution costs from the streetlighting class, not just secondary distribution costs." 4 Tr 2795.

Similarly, the Staff argued that streetlighting customers use the distribution system and should be allocated some of the costs. The Staff stated that:

> [t]he Company currently uses class-peak allocators to allocate distribution plant costs which utilize the non-coincident peak demands of each customer class. This method ensures that each customer class that uses the Company's distribution system is assigned an amount of costs corresponding to their use of the system. The fact that streetlights do not contribute to peak-loads is properly reflected in the very small percentage of costs that are allocated to the streetlighting class using the current class-peak allocators. Every class-peak allocator used to allocate distribution plant costs in COSS accounts 360-369 assigns less than 1% of those costs to the streetlighting class. Whether or not the streetlighting class causes system expansion, system capacity growth, or reliability investments does not negate the fact that it uses the Company's distribution system.

5 Tr 3729.

The ALJ noted that the Commission rejected similar arguments from MI-MAUI in the December 1 order. Rather, the ALJ stated, the Commission "found it appropriate to include the streetlighting class in the allocation because streetlights use the secondary distribution system. This PFD finds that using alternative class peak for allocating secondary distribution costs to the streetlighting class is appropriate for the reasons stated above." PFD, p. 462 (footnote omitted).

In exceptions, MI-MAUI asserts that its proposal in the immediate case can be distinguished from its recommendation in Case No. U-21297. MI-MAUI states that, in Case No. U-21297, it recommended that "the streetlighting class be excepted from the allocation of all secondary distribution costs (capital expenses and O&M), whereas in this case, MI-MAUI is requesting that the streetlighting class only be excepted from the allocation of secondary distribution capital expenses while paying its share of O&M costs." MI-MAUI's exceptions, p. 6. MI-MAUI argues that its proposal in this case acknowledges the streetlighting class's use of the grid and its responsibility for maintenance but recognizes that the class does not contribute to capacity or grid growth. In MI-MAUI's opinion, its proposal more equitably allocates distribution costs pursuant to MCL 460.11(1).

Consumers objects to MI-MAUI's request that streetlighting customers be exempted from allocation of secondary distribution capital costs. The company states that "[t]he secondary distribution grid is constructed to support all uses of the grid" and, therefore, streetlighting customers should be allocated "their proportionate share of the system." Consumers' replies to exceptions, pp. 115-116.

Similarly, the Staff argues that the ALJ "properly considered the record evidence and made the correct recommendation to allocate the streetlighting rate class its fair share of distribution plant costs including distribution capital expenses to reflect its use of the Company's distribution system." Staff's replies to exceptions, p. 26.

The Commission finds persuasive Consumers' position that "[t]he secondary distribution grid is constructed to support all uses of the grid" and streetlighting customers use the upstream facilities that are connected to streetlighting infrastructure to bring electricity for streetlighting purposes. Consumers' replies to exceptions, p. 115. Therefore, the Commission finds that MI-MAUI's proposal to exempt the streetlighting class from allocation of secondary distribution capital costs should be denied.

c. Association of Businesses Advocating Tariff Equity Recommendation

ABATE recommended that Consumers' purchased capacity costs be allocated using a 4 coincident peak (4CP) 100-0-0 allocator, which is consistent with DTE Electric's allocation method. ABATE noted that Consumers projects $324.75 million in purchased capacity and that the company currently allocates on a 4CP 75-0-25 basis. ABATE argued that it is inconsistent with cost-causation principles to allocate purchased capacity using the 4CP 75-0-25 allocator. ABATE explained that:

> the 4CP 75-0-25 allocator is used to allocate fixed production costs for Consumers' generation assets, which are not split into energy or capacity buckets prior to allocation. The fixed production costs that are allocated with the 4CP 75-0-25 allocator are items like rate base, the return on- and of- investment (return on rate base and depreciation expense), and fixed O&M of Consumers' traditional generation facilities. These production assets provide both capacity and energy, and as such, there has been a long standing practice by the Commission in Michigan to allocate the costs in a manner that reflects both of the capacity and energy benefits. This is not the case with Consumers' other purchased capacity costs. The purchased capacity costs do not provide any arguable energy benefits or fuel savings as they are purely related to the cost of meeting MISO's [Midcontinent Independent System Operator, Inc.'s] resource adequacy requirements, and therefore, it is improper to allocate any portion of these costs on the basis of energy. This is because these costs have been set based on either using the transfer price mechanism of Consumers' renewable energy plan or negotiated by Consumers based on the market price for capacity within the MISO footprint.

4 Tr 2771-2772 (footnote omitted). ABATE requested that the Commission approve the $324.75 million in purchased capacity costs be allocated using 4CP 100-0-0 because it more accurately reflects cost causation.

Consumers did not object to ABATE's proposal, but stated that it calculated a slightly different rate class impact. The company asserted that the result of its corrected calculation "would increase primary costs by $0.085 million compared to what was calculated by ABATE." 4 Tr 1342.

The Staff disputed ABATE's proposed change to the allocator, arguing that it:

> views production assets, including those that provide purchased power capacity to the Company, as providing both energy and capacity. Therefore, Staff's position is that there should continue to be some recognition of both energy use and capacity use in the allocation factor for purchased power capacity costs. The Commission has recognized the dual nature of production assets going back to 1976 in Case No. U-4771 where the Commission recognized a production allocator of 12 CP 75/0/25. From that time, every COSS adopted in the Company's rate cases has had 25% of production assets determined by total energy. This 25% energy weighting

> should continue to be approved by the Commission for purchased power capacity costs.

5 Tr 3727. The Staff also disagreed with ABATE's claim that the 4CP 75-0-25 allocation method is inconsistent with cost causation principles. The Staff stated that "ABATE fails to account for all causative elements associated with non-variable production costs. Demand during the peak period is just one example of a cost-causative element. The Company also incurs non-variable production costs for reasons besides pure demand. These costs should not be allocated the same way as demand costs." 5 Tr 3727-3728.

Furthermore, the Staff asserted that the allocation of costs associated with company's capacity generation and costs for purchased capacity should be the same. The Staff explained that:

> any split between energy and capacity payments in a PPA are a result of negotiating that PPA. No evidence has been presented in the instant case showing that what has been negotiated as a capacity price, including the manner in which the associated cost is incurred or paid, is appropriate to be considered as purely a demand cost. Nor has it been shown which portion of these capacity PPA costs are associated purely with purchases of capacity, as opposed to a combined energy and capacity PPA. For these reasons, Staff recommends the Commission reject ABATE's proposal to change the allocation method for purchased power capacity costs and continue to approve the 4 CP 75/0/25 method.

5 Tr 3728.

ABATE responded that purchased capacity costs do not provide any energy benefits or fuel savings; rather, the costs are solely related to the cost of meeting MISO's resource adequacy requirements. In addition, ABATE stated that the:

> Staff's view of these assets as "production assets" which provide both "energy and capacity" is therefore inconsistent with their actual function. (See Pung 5 Tr 3727-28.) Indeed, as Staff acknowledged, the "capacity portion of Consumers' PPAs are the payments made for the ZRCs [zonal resource credits] provided in to the market by the PPA," which "ZRCs are the amount of capacity credit that the PPA provides to the company to offset Consumers' capacity demand in the MISO market" and "do not provide any value in the energy market making these expenses solely demand costs." (Exhibit AB-27.) Staff's assertion that Consumers "also incurs non-variable production costs for reasons besides pure demand" which production

> “costs should not be allocated the same way as demand costs” is therefore irrelevant to this issue. (Pung 5 Tr 3728.) Further, Staff’s claim regarding the purported “principle that a portion of non-variable power supply costs should be allocated based on total energy usage” which “does not change whether the Company is generating the capacity itself or purchasing the capacity through a purchase power agreement (PPA)” is therefore, again, inconsistent with the actual purpose and treatment of these costs. (Id.)

ABATE’s initial brief, pp. 51-52. Moreover, ABATE asserted that the 4CP 100-0-0 allocation method was approved for DTE Electric in Case No. U-21224 and noted that Consumers does not object to ABATE’s proposal in this case.

The Staff disputed ABATE’s claims that the Staff acknowledged that the capacity portion of Consumers’ PPAs are payments for the ZRCs supplied into the market by the PPA and that the ZRCs do not have any value in the energy market and, thus, are purely demand costs. The Staff stated that the information relied upon by ABATE was provided by Consumers, not the Staff. *See*, Staff’s reply brief, p. 16. In addition, the Staff asserted that it addressed ABATE’s arguments in the Staff’s initial brief and that the Staff maintains its arguments and recommendations set forth therein.

The ALJ found the Staff’s arguments persuasive. She stated that “[as the Staff] pointed out, the Commission has long recognized that production costs, whether associated with the company’s own generating plants or PPAs should recognize total energy as part of the weighting. Therefore, ABATE’s recommendation is rejected.” PFD, p. 465.

Consumers objects, arguing that the ALJ “does not explain how that could be correct given the inconsistency with the treatment of the same costs for DTE [Electric]. The Commission should adopt ABATE’s COSS adjustment as corrected by Company witness Davis.” Consumers’ exceptions, p. 162.

In exceptions, ABATE asserts that the ALJ's recommendation should be rejected. ABATE explains that purchased power capacity costs "do not have an energy component and it is improper to allocate any portion of these costs on an energy basis. Stated differently, these purchased capacity costs are ***purely capacity costs*** and ***contain no energy component***." ABATE's exceptions, p. 6 (emphasis in original). ABATE reiterates its recommendation to allocate purchased capacity costs on a 4CP 100-0-0 basis.

The Staff responds, asserting that ABATE simply reiterates the arguments that were considered and rejected by the ALJ. The Staff contends that the ALJ "properly considered the record evidence and made the correct recommendation to maintain the longstanding practice of recognizing that production costs, whether associated with the Company's own generation or with PPA's should recognize total energy as part of the weighting." Staff's replies to exceptions, p. 27 (citation omitted).

MNSC asserts that, pursuant to MCL 460.11(1), "[t]here is no reasonable dispute that purchased capacity costs are 'production-related costs.' Therefore, they are to be allocated using the 75-0-25 method unless the Commission determines that doing so does not ensure that rates are equal to the cost of service." MNSC's replies to exceptions, p. 37.

The Commission finds that the ALJ's findings and recommendation are reasonable and prudent and should be adopted. ABATE argues that the current 4CP 75-0-25 allocation method is inconsistent with cost causation principles because "purchased capacity costs do not provide any arguable energy benefits or fuel savings as they are purely related to the cost of meeting MISO's resource adequacy requirements, and therefore, it is improper to allocate any portion of these costs on the basis of energy." 4 Tr 2772. The Commission has long recognized the "dual nature" of production assets: 75% demand and 25% total energy usage. 5 Tr 3727; *see*, May 10, 1976 order in Case No. U-4771. The Commission agrees with MNSC that "[t]here is no reasonable dispute that purchased capacity costs are 'production-related costs'" for the purposes of MCL 460.11(1). MNSC's replies to exceptions, p. 37. Further, as noted by the Staff, "ABATE fails to account for all causative elements associated with non-variable production costs." Staff's initial brief, p. 107. The Staff argues that these costs should not be allocated the same as demand costs. The Commission agrees. In addition, the Staff aptly points out that "[t]he principle that a portion of non-variable power supply costs should be allocated based on total energy usage . . . does not change whether the Company is generating the capacity itself or purchasing the capacity through a [PPA]." 5 Tr 3728. The Commission agrees with the Staff that there is no evidence on the record demonstrating that the negotiated capacity price of a PPA should be considered as a demand cost only. Furthermore, there is no evidence demonstrating "which portion of these capacity PPA costs are associated purely with purchases of capacity, as opposed to a combined energy and capacity PPA." 5 Tr 3728. Therefore, the Commission finds that ABATE's proposal to change the allocation method for purchased power capacity costs to 4CP 100-0-0 is denied.

B. Rate Design

Consumers proposed to use the same methodology in Case No. U-21389 as the company presented in its previous electric rate case[17] and stated that its electric base rates were designed to balance multiple objectives such as rate stability and promotion of an attractive business climate, among other factors, in order to be efficient and fair.

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[17] The January 19 order approved a settlement agreement attached to the order as Exhibit A. Specific elements of rate design were not discussed in the settlement; however, the rate adjustments are set forth in Attachment A to the settlement.

Regarding residential rate classes, Consumers testified that it would maintain its current rate structure for all residential rates and that its residential customers' bills are projected to increase about 3.4%; however, according to Exhibit A-16, Schedule F-4.0, residential rates in some residential classes and usage may receive increases of up to 6.0%. 3 Tr 202-203; *see*, Exhibit A-16, Schedule F-4.0, pp. 1-12.

Consumers also testified that it made adjustments to its large general service self generation (GSG-2) rate but did not believe the underlying issues[18] were sufficient to change the design of the GSG-2 rate. Consumers testified that it also made an adjustment to correct an error that occurred in Consumers' electric rate case, Case No. U-20134,[19] wherein the company was noted to have excluded customer-owned substations from its COSS resulting in an overallocation of substation costs. Additionally, Consumers testified that it made adjustments to the lifeline credits for senior citizens and low-income customers. 3 Tr 198-200; *see*, Exhibit A-16, Schedule F-2.1.

The record does not indicate that any party opposed these adjustments. PFD, p. 466.

No exceptions were filed on these adjustments.

Accordingly, the Commission adopts these proposed adjustments, as discussed in this order.

In addition, Consumers proposed several design changes. 3 Tr 204-205. For its energy intensive program (EIP) rate, Consumers proposed to move the monthly credit that is currently

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[18] Consumers testified that the adjustments seemed to indicate that perhaps "large standby customers pay less under the market-based rate design structure for production and transmission standby service than they would under an embedded cost of service design." 3 Tr 199.

[19] The January 9, 2019 order in Case No. U-20134 approved a settlement agreement that resolved all issues in the case but one. A second order in the case was issued on May 19, 2020, approving a settlement agreement that resolved the remaining issue.

embedded in energy charges to a separate line item on the monthly billing. For its large economic development rate (Rate LED),[20] the company proposed to: (1) clarify in its tariff that a facilities allowance may be part of the incremental distribution charge, (2) add a day-ahead locational margin price (LMP) option, and (3) note in its Rate LED tariff that Consumers may match energy crediting options under its large customer renewable energy program (LC-REP) with that of Rate LED if the customer has elected both services. 3 Tr 196. For its GSG-2 rate, Consumers proposed to eliminate the $200 monthly access charge. 3 Tr 204-205.

The Staff generally supported Consumers' proposed rate design but disagreed with the company's view that energy costs are considered as variable and production capacity costs are considered as fixed. 5 Tr 3663.

While they did not provide testimony regarding overall rate design, MNSC argued that Consumers' residential customers pay more because they are subsidizing industrial and commercial rates through added distribution costs. 4 Tr 2633.

ABATE proposed three changes to Consumers' rate design: (1) that Consumers offer a proxy plant option for the incremental COS charge to Rate LED customers; (2) that the threshold load for Rate LED eligibility be lowered to 5,000 kW;[21] and (3) that a 20-year limit be placed on Rate LED contracts. 4 Tr 2741, 2744, 2746.

These matters are discussed individually below.

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[20] Not to be confused with LED luminaires or LED technology. In this section of the instant order, LED refers to large economic development.

[21] The parties used the terms 5,000 kW and 5 MW synonymously. The parties also used the terms 35,000 kW and 35 MW synonymously.

GLREA testified that it is opposed to any rate that is based on or includes economic incentives, that demand charges should be eliminated, and all customers should pay the same price per kWh. GLREA asserted that the government, not utility customers, should fund economic incentive discounts. 4 Tr 3184-3188. GLREA also argued that the Commission should require that a comprehensive review of Consumers' rate book be conducted. 4 Tr 3204.

Regarding GLREA's suggestions about rate design, the ALJ agreed with Consumers, ABATE, and the Staff, that GLREA's proposals constitute a significant deviation from class COSS-based ratemaking and should not be adopted. PFD, p. 525 (citing 3 Tr 221-222; Staff's initial brief, pp. 120-124; and ABATE's initial brief, pp. 69-72). The ALJ also found that a comprehensive review of Consumers' rate book is a function of a rate case and conducting an additional review would be unnecessary and duplicative. PFD, pp. 525-526.

No exceptions were filed on GLREA's suggestions.

The Commission finds that the ALJ's opinions and recommendations related to GLREA's suggestions are well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's recommendations for the reasons stated in the PFD.

1. Miscellaneous Rate Modifications

a. Residential Rate Design

Consumers presented its plan to use the company's current residential rate structure in this case. The company opined that maintaining current residential rate structures for each rate option, including the Residential Smart Hours Rate, Residential Summer On-Peak Basic Rate, Residential Service Secondary Non-Transmitting Meter Rate, and Residential Nighttime Savers Rate will provide price stability for customers. Consumers projected that residential bills would increase an average of 3.4% in the projected test year based on its case, as filed. 3 Tr 202.

While not specifically opposing Consumers' residential rate design, MNSC argued that it calculated that Consumers' residential customers currently pay more than the national average per kWh of energy (Consumers' 18.11 cents per kWh versus a national average of 15.47 cents per kWh). 4 Tr 2629.

Consumers presented that, according to the Energy Information Administration, Consumers' residential customers pay $9.00 per month less than the national average ($134 per month projected as the average national monthly bill versus $125 per month projected for the average Consumers' residential bill). 3 Tr 203.

MNSC also argued that the difference between residential rates and industrial rates provides a proxy for the cost of distribution because residential rates generally include the cost of generation, transmission, and distribution, while commercial and industrial rates generally include only generation and transmission, and that Consumers' residential customers pay more because they are subsidizing industrial and commercial rates through added distribution costs. 4 Tr 2633, 2636.

The Staff refuted this argument, stating that the difference in costs for these rate classes is due to numerous other factors. Staff's initial brief, pp. 112-113.

No exceptions were filed on Consumers' residential rate design. Accordingly, the Commission adopts the company's residential rate design.

b. Large General Service Self Generation Rate Monthly Access Charge

Consumers proposed to discontinue its $200 monthly system access charge included in Rate GSG-2 for those customers that have generation that meets or exceeds load. 3 Tr 196, 204; *see*, Exhibits A-120 and A-16, Schedule F-5. The company stated that it has never had the necessity to administer the $200 charge and, upon its elimination, all customers on the GSG-2 rate would pay $100 for system access regardless of generation. 4 Tr 1850.

No party opposed the elimination of the GSG-2 $200 monthly access charge and no exceptions were filed. Accordingly, the Commission finds that the charge should be eliminated as proposed by Consumers.

2. Large Economic Development Tariff

As stated above, Consumers proposed three changes to its Rate LED: (1) implementing a facilities allowance, (2) permitting selection of day-ahead LMP, and (3) aligning the Rate LED/LC-REP energy credit and energy charge. 3 Tr 196, 206. Additionally, ABATE suggested that a proxy plant pricing option be developed for Consumers' Rate LED and that the minimum load requirement to qualify for Rate LED be lowered from 35,000 kW to 5,000 kW.[22] ABATE also suggested that a maximum Rate LED contract term of 20 years be established. 4 Tr 2741-2745.

a. Rate LED Facilities Allowance and Proxy Plant Pricing Option

Consumers proposed to add to its Rate LED tariff language that a facilities allowance may be available that will apply as part of the incremental distribution charge to help cover the upfront costs of bringing facilities to Michigan. Consumers reported that prospective customers have requested a facilities allowance and have indicated that other utilities, such as DTE Electric, offer such an allowance. The company proposed to calculate the facilities allowance individually by facility according to the proposed facility's net present value (NPV) of margin.[23] 3 Tr 196, 206-207.

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[22] *See*, December 22, 2021 order in Case No. U-21160, p. 3.

[23] In this instance, NPV of margin is defined as the proposed facility's non-energy related costs based on the facility's expected load over the term of the contract. Non-energy related customer costs would include the sum total of system contribution, power supply capacity, and distribution charge revenue.

ABATE supported the facilities allowance but proposed that Consumers offer the allowance and a general Rate LED option based on a proxy plant model. ABATE stated that a proxy plant option would attract more customers than Consumers' "current incremental cost of service rate based on the market price for capacity and energy[.]" 4 Tr 2741. ABATE proffered Consumers' New Covert Generating Facility (Covert plant)[24] as an appropriate proxy plant that is comparable to DTE Electric's Blue Water Energy Center (BWEC) proxy plant. 4 Tr 2740-2742.

Hemlock supported the facilities allowance, stating that such an allowance is available in DTE Electric's Rate D13 and that the allowance would be very helpful in bringing new load to Michigan. Hemlock's initial brief, p. 7. METC also supported the facilities allowance as a way to meet the needs of customers who may, perhaps, locate facilities in Michigan. METC's initial brief, p. 23.

MNSC and GLREA were opposed to the facilities allowance. MNSC argued that no evidence is on the record to support the idea that adding a facilities allowance to Rate LED will, in fact, attract new facilities to Michigan. MNSC's initial brief, p. 49. Further, MNSC argued that the economic development surveys[25] relied on by Consumers are nothing more than informal reader polls that are not based on any scientific evidence. *Id*. Finally, MNSC opined that Consumers has no "mandate or authority" to act as a "quasi-governmental economic development entity." *Id*.

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[24] *See*, the June 23, 2022 order in Case No. U-21090 (June 23 order).

[25] *Area Development Magazine* was the source of the surveys. It is a magazine and website devoted to facility planning, site selection, and related matters. *See*, https://www.areadevelopment.com/ (accessed February 26, 2024.)

Similarly, GLREA testified to its opposition to any rate based on economic incentives and averred that the state, not ratepayers, should pay for economic development incentives. 4 Tr 3184.

The Staff implied that it did not oppose a facilities allowance *per se*, stating that it is similar to a CIAC, but opposed calculating the facilities allowance based on NPV of margin as proposed by Consumers, in part, because the proposed calculation includes power supply revenue from Rate LED customers. The Staff also argued that both embedded distribution costs and a system contribution charge should be included in any facilities allowance calculation. Staff's initial brief, pp. 113-119. In summary, the Staff argued that, if the Commission approves a facilities allowance, "it should exclude power supply revenue and only include distribution revenue and system contribution charge revenue. If the Commission approves the Company's facilities allowance as proposed by the Company, then the customers' power supply revenue should be net of interruptible credits." Staff's initial brief, pp. 115-116.

The Staff also opposed implementing the Covert proxy plant calculation for several reasons. First, Consumers' acquisition of the Covert plant is "materially different from DTE's construction of its BWEC, on which DTE's proxy plant rate option is based." Staff's initial brief, p. 117 (citing 5 Tr 3678; 3 Tr 240). The Staff explained that "[s]etting a proxy plant rate on the acquisition of a plant assumes that another plant would be available for purchase at the same price if one were needed to meet new or expanded load on Rate LED[,]" but no party "identified whether another plant is available for purchase. ABATE's reliance on the purchase of the Covert facility also does not consider how broader market forces would affect the price of another similar plant acquisition." Staff's initial brief, pp. 117-118. The Staff also averred that Rate LED is currently based on a proxy solar plant rendering a new proxy plant rate unnecessary. *Id*., p. 118. Finally, the Staff opined that classifying costs as fixed or variable, as ABATE suggests, when recovering costs via demand or energy charges does not adequately consider the causation of the costs determined in a COSS. *Id*.

The ALJ recommended that the facilities allowance should be denied because the supporting parties have not demonstrated that it would bring additional large facilities to the state and the allowance would lead to other ratepayers paying more embedded costs. PFD, p. 500.

Additionally, the ALJ agreed with the Staff that:

> using the Covert facility as a proxy plant is not appropriate based on the company's acquisition of the plant as opposed the [*sic*] DTE's construction of the Blue Water Energy Center. [The] Staff is concerned that should a new or expanded load require more generation, there is no assurance that a facility such as Covert would be available with similar capacities at a similar price.

Id., p. 501. The ALJ, in agreement with the Staff, also recommended that, should the facilities allowance be approved, Rate LED customers should "pay the same embedded distribution costs as others and a system contribution charge." *Id*., p. 500. Additionally, the ALJ recommended that, if the Commission approves the facilities allowance, that the proxy plant option be denied because it "goes against the standard methodology of determining power supply charges by splitting revenue between fixed and variable costs." *Id*., p. 501.

In its exceptions, the Staff argues that the ALJ correctly recommended that the Commission reject the implementation of a facilities allowance in Rate LED. However, the Staff points out that the ALJ incorrectly stated the Staff's position when she stated that "'this PFD recommends the Commission adopt Staff's recommendation that Rate LED customers be required to pay the same embedded distribution costs as others and a system contribution charge.'" Staff's exceptions, p. 5 (quoting PFD, p. 500). The Staff states that its correct recommendation is that "if the Company's facilities allowance is approved without Staff's modification to exclude power supply revenue" (*see*, Staff's initial brief, pp. 115-116), then:

> the approved facilities allowance [should] only include distribution revenues and system contribution charge revenues. (Staff Initial Br, p 116.) If the Commission approves the facilities allowance as proposed by the Company, then Staff further recommends that the new Rate LED customer's applicable power supply revenue be net of interruptible credits. (*Id*.) Customers on Rate LED will already pay the established distribution and system contribution charges by taking service on the rate, while the actual contention between Staff, the Company, ABATE, and MNSC are what, if any, revenues should be included in the allowance. For the reasons presented in the PFD the Commission should deny the Company's proposed facilities allowance, and if it is approved then the facilities allowance should only include revenue from distribution and the system contribution charges.

Staff's exceptions, p. 6 (emphasis omitted).

Consumers excepts to the ALJ's recommended denial of the facilities allowance. Consumers argues that the allowance would benefit Rate LED customers in two ways: (1) by lowering the company's revenue requirement through collection of miscellaneous revenues and allocating said revenues to all rate schedules; and (2) through economic development which would offer opportunities to all customers such as jobs, increased income, and increased quality of life, among others. Consumers' points to two corporate surveys conducted by *Area Development Magazine* that listed energy costs as being in the top 10 considerations for the location of new facility sites. Relying on the two surveys, Consumers opines that Michigan must offer competitive rate options if the state wants economic growth. Consumers' exceptions, pp. 164-165.

Consumers also excepts to the ALJ's recommendation to exclude power supply revenue from the facilities allowance. Consumers' exceptions, p. 165 (citing 5 Tr 3665-3667). Consumers argues that capacity costs should be included in the facilities allowance because Rate LED benefits all ratepayers and, when the contract ends, Rate LED customers "will contribute to the recovery of full embedded costs." Consumers' exceptions, p. 165. Additionally, Consumers claims that DTE

Electric's Rate D13 Extra Large High Load Factor for load capacity of at least 50,000 kW[26] includes a "facilities allowance based on two times revenue, including production capacity revenue." *Id*., (citing 3 Tr 217-218).

Further, Consumers reiterates its support of ABATE's proxy plant proposal. Consumers argues that calculation of a facilities allowance based on a proxy plant offers more stability than does a market index option. Consumers avers that, without the proxy plant-based facilities allowance, the company is at a disadvantage to compete for economic development. The company also points to the loss of "embedded costs that would have come from the sales margins provided under the economic development rate by the load addition or expansion." Consumers' exceptions, p. 167 (citing 4 Tr 2742).

ABATE denies that the record supports the ALJ's conclusion that adoption of a facilities allowance, as presented, would result in more embedded costs being paid by ratepayers. ABATE's exceptions, p. 7. ABATE reiterates that "[t]he facilities allowance would go toward the cost of any incremental distribution investments necessary to serve the customer based on the expected sales margins (i.e. the expected contribution toward Consumers' embedded costs) that would be provided by the customer over the term of the customer's contract." ABATE's exceptions. p. 8. ABATE argues that the reasons against the adoption of the facilities allowance are "overstated" and that the allowance will not prevent Rate LED customers from paying the costs they cause and will not result in customer subsidies. *Id*. Further, ABATE argues that the proxy plant option based on the Covert plant will improve Rate LED and, again cites DTE Electric's proxy plant calculation based on the BWEC. *Id*., pp. 9-10.

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[26] *See*, https://www.dteenergy.com/content/dam/dteenergy/deg/website/business/service-and-price/pricing/BusinessElectricRates.pdf (accessed February 26, 2024).

Hemlock excepts to the ALJ's recommended rejection of the facilities allowance and the proxy plant method of calculation. Hemlock reiterates its case presentation and its agreement with ABATE and Consumers on the matter, describing the Staff's concern over embedded production capacity as being "without merit." Hemlock's exceptions, p. 4.; *see*, *id*., pp. 2-4. Further, Hemlock asserts that "[t]he proxy plant pricing option would provide additional rate stability for the Rate LED customers." Hemlock's exceptions, p. 5.

In its replies to exceptions, MNSC argues that, in site selection, the cost of labor overshadows the cost of energy and it is "not plausible that adding a facilities allowance to the LED rate will bring the sweeping, transformational economic benefits to Michigan that [Consumers] posits." MNSC's replies to exceptions, p. 43. MNSC characterizes the facilities allowance as "an unwarranted subsidy of customers who will already receive extraordinary discount[s.]" *Id*., p. 47. Additionally, MNSC argues that "[u]sing a proxy plant [such as the Covert plant] that will likely have lower costs than the true marginal cost of incremental capacity and energy is just one more way in which these parties are seeking discounts and subsidies for themselves at the cost of the rest of Consumers' customers." *Id*., p. 51.

In its replies to exceptions, Hemlock reiterates the reasons it supports the facilities allowance and discounts the Staff's concerns regarding calculation of the allowance, asserting that the allowance should be approved "on a comparable basis to the DTE rate." Hemlock's replies to exceptions, pp. 1-3.

Consumers replies that the ALJ's recommendation to reject the facilities allowance does not take sufficient note of the economic benefits the allowance would provide to the company's customers and the state. Consumers' replies to exceptions, p. 116. Additionally, Consumers reiterates that power supply revenues were appropriately included in its initial proposal. *Id*. (citing 3 Tr 216-218; Consumers' exceptions, p. 165).

The Staff replies that it does not oppose the entirety of the proposed facilities allowance, only both of the proposed calculations of the allowance. The Staff reiterates that the allowance should not include power supply costs. Staff's replies to exceptions, pp. 22-23.

The Commission finds the ALJ's recommendations related to the rejection of Consumers' proposed facilities allowance are well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's recommendations for the reasons stated in the PFD. The Commission is actively supportive of economic development efforts in Michigan, including its approval of Rate LED in its December 22, 2021 order in Case No. U-21160. However, the Commission agrees with the ALJ that "the arguments regarding the proposed facilities allowance creating a subsidy for Rate LED customers" are persuasive. PFD, p. 499. MCL 460.11(1) requires the Commission to "ensure the establishment of electric rates equal to the cost of providing service to each customer class," and sets forth a methodology for making such calculation. In approving Rate LED, the Commission specifically found that the rate reflected the marginal cost of serving the new load, and as such, "the proposed Rate LED complies with Michigan law" and that "approval of Consumers' amended application will not result in an increase in the cost of service for any customer[.]" December 22, 2021 order in Case No. U-21160, p. 4. The Commission will continue to support economic development efforts, including innovative rate offerings, but reminds Consumers that such offerings must reflect COS principles and remain consistent with statutory provisions that prohibit cross-subsidization.

This reasoning also applies to the proposed development of the Covert plant as a proxy plant for Rate LED. The Commission believes that the Covert plant is unlikely to be replicated and thus would not offer the rate stability asserted by Consumers and Hemlock. Should Consumers again propose a new or optional tariff for Rate LED, the Commission expects the proposal to include a detailed pricing plan that is consistent with COS principles and reflects the marginal cost of serving the new load, as discussed above. Again, the proposed pricing must be consistent with statutory provisions that prohibit cross-subsidization, and "not result in an increase in the cost of service for any customer." December 22, 2021 order in Case No. U-21160, p. 4.

b. Rate LED Day-Ahead LMP and Real-Time LMP

Consumers proposed that Rate LED customers, energy intensive by nature, be given the choice of opting for day-ahead LMP, as well as real-time LMP, so that customers may obtain some relief from any volatility in energy prices. 3 Tr 196, 207.

ABATE supported the day-ahead LMP option because day-ahead LMP is generally less volatile than real-time LMP. ABATE opined that the ability of customers to better manage hour-to-hour pricing will make the rate more competitive which, in turn, will attract more customers to the jurisdiction thereby benefiting all Consumers' customers. ABATE asserted that the ability to select day-ahead LMP may prevent rate subsidization. 3 Tr 196, 207-208; 4 Tr 2738-2739. Hemlock also supported the day-ahead pricing option. Hemlock's reply brief, p. 5. The Staff did not oppose it. 5 Tr 3665.

The ALJ recommended that the Commission approve the proposal. PFD, p. 499.

In its exceptions, Consumers agreed with the ALJ. Consumers' exceptions, pp. 162-163.

No party disagreed with adding the day-ahead LMP option to Rate LED. Accordingly, the Commission finds that this pricing option should be added to Rate LED as proposed by Consumers.

c. Rate LED/LC-REP Energy Credit Alignment

Consumers proposed to allow Rate LED customers that also take service under the LC-REP rate to match their energy billing under Rate LED with the energy credit under LC-REP. Consumers argued that this practice would help to eliminate the month-long gap between the time energy credits are provided under LC-REP and the time the customer is billed under Rate LED. 3 Tr 196, 205-208.

ABATE supported Consumers' proposed alignment of Rate-LED and LC-REP costs and credits because it would improve Rate LED's competitiveness as an economic development rate. Additionally, ABATE noted that the alignment would not change either the energy charges or the credits. 4 Tr 2739-2740. Hemlock also supported the proposal. Hemlock's reply brief, p. 5. The Staff did not oppose the change. 5 Tr 3665.

The ALJ recommended that the Commission approve the proposal. PFD, p. 499.

In its exceptions, Consumers agreed with the ALJ. Consumers' exceptions, p. 163.

No party opposed the proposed alignment of Rate LED and LC-REP as discussed in this order. Accordingly, the Commission finds that Rate LED customers that also take service under the LC-REP program should be permitted to align their energy billing under Rate LED with the energy credit under LC-REP.

d. Minimum Load Qualification for Rate LED.

ABATE recommended that the Commission require Consumers to lower its minimum demand for Rate LED eligibility from 35,000 kW to 5,000 kW. ABATE reasoned that 5,000 kW is a sizeable load addition or expansion and would permit greater economic development. However, ABATE averred that, should a proxy plant option be added to Rate LED, it should only be available to customers with demand of 35,000 kW or more until the company has time to assess the proxy plant effect. 4 Tr 2744-2745.

Consumers, METC, and Hemlock supported the lower eligibility threshold as a method of bringing additional economic development to Michigan, but MNSC and the Staff opposed it. 3 Tr 220; 4 Tr 3350; 5 Tr 3679-3680; Hemlock's initial brief, p. 10; MNSC's initial brief, pp. 51-53; Staff's initial brief, p. 119. The Staff argued that the Commission has determined that the current threshold for Rate LED eligibility is appropriate and that loads of less than 35,000 kW would be neither large nor unique. 5 Tr 3679-3680; *see*, December 22, 2021 order in Case No. U-21160. MNSC argued that the issue required a more robust analysis than is provided in the instant case and that Consumers is not legally required to "be an economic development agent for the State of Michigan." MNSC's initial brief, pp. 51-52.

The ALJ found the Staff's and MNSC's arguments to be persuasive and consistent with the Commission's previous findings in Case No. U-21160. Accordingly, recommended that the current Rate LED threshold eligibility of 35,000 kW should remain. PFD, p. 501.

In its exceptions, Consumers reiterates its support for a 5,000 kW minimum load to qualify for Rate LED. Consumers' exceptions, pp. 168-169.

ABATE also excepts and argues that Consumers presented situations where potential Rate LED customers did not meet the minimum 35,000 kW requirement and, as such, the current threshold prevents economic development. ABATE's exceptions, pp. 10-11.

In its exceptions, Hemlock points out that "[t]he lack of customers on Rate LED is evidence that the rate has been unsuccessful at attracting new loads to Michigan[,]" and the load threshold should be lowered. Hemlock's exceptions, p. 6; *see*, *id*., pp. 5-6.

In replies to exceptions, MNSC asserts that "[t]he LED rate package is already an extraordinarily generous set of discounts and subsidies[ ]" and that the parties have not "justified vastly expanding the set of customers who can take advantage of the rate." MNSC's replies to exceptions, p. 39. Additionally, MNSC argues that ABATE and Consumers have not met their burden of proof or shown that lowering the threshold load for Rate LED is necessary, reasonable, or prudent. *Id.*, p. 55.

In its replies to exceptions, the Staff opposes lowering the threshold load for Rate LED. The Staff asserts that the argument that more customers would take service under the rate if the threshold was lowered is unproven. The Staff also asserts that there has been an insufficient amount of time since Rate LED was implemented to properly determine whether the set threshold is inappropriate. Staff's replies to exceptions, p. 24.

The Commission is not persuaded that lowering the threshold load requirement for Rate LED from 35,000 kW to 5,000 kW is appropriate. Lowering the minimum load requirement so drastically is contrary to the December 22 order in Case No. U-21160, wherein the Commission carefully considered all aspects of the proposed Rate LED and approved a minimum load of 35,000 kW for new or expanded facilities customers that are large and unique. The rate is still relatively new and the Commission finds that the parties have not offered sufficiently compelling arguments to merit a change in the threshold limit set in that order. Accordingly, the Commission rejects lowering the threshold load for Rate LED.

e. Maximum Contract Term for Rate LED

ABATE proposed that Rate LED should require a maximum contract term of 20 years in addition to its required minimum contract term of 15 years. ABATE reasoned that this would ensure that customers would begin paying normal rates in a reasonable amount of time rather than continuing to pay the discounted Rate LED. 4 Tr 2745-2746. Consumers agreed with the 20-year contract limit. Consumers' initial brief, p. 434. Hemlock remarked that no party opposed the

20-year contract limit and agreed that it should be approved. Hemlock's reply brief, p. 8. The Staff did not indicate that it opposed the proposal.

The ALJ recommended that the Commission approve the proposal. PFD, p. 499.

In its exceptions, Consumers agreed with the ALJ. Consumers' exceptions, p. 163.

The Commission finds that no parties opposed ABATE's proposal and, accordingly, approves the 20-year contract limit for Rate LED.

C. Tariff Issues

1. Electric Vehicle Tariff Language

Relating to Consumers' Electric Rate C4.4, Sheet C-15.00, Application of Rates, Resale, the Staff recommended removing the following language: "For the purposes of this tariff, the provision of electric vehicle charging service for which there is no direct per kWh charge shall not be considered resale of service." The Staff testified that this language is confusing because it was replaced by newer Rate C4.4, Sheet C-16.00 language in the January 19 order. 5 Tr 4032-4033. The ALJ noted that Consumers agreed with the Staff and neither party briefed the matter in their reply briefs. Therefore, the ALJ regarded this issue as resolved and recommended removal of the language as suggested by the Staff. PFD, pp. 502-503.

As no parties opposed the Staff's proposal, the Commission approves the tariff language change as discussed in this order.

2. Streetlight Outage Reporting

Consumers testified regarding its on-line streetlight outage self-reporting system (SOAR), reporting that SOAR has increased customer satisfaction, reduced IT costs, reduced calls to contact centers, and improved the company's handling of streetlight outages. The company reported that it had made a number of improvements to SOAR in previous years and continues to do so. 4 Tr 2272-2275. Consumers also testified that its current streetlight tariff provides for an outage credit that is based on the date the outage is reported, continuing until the outage is repaired. The credit is issued within 90 days of the outage being repaired. 4 Tr 2275.

While MI-MAUI appreciated Consumers' payment of outage credits and its willingness to ensure that customers are not paying for streetlighting that is not working, it argued that there has been a 71% increase in reported streetlight outage days and a more than 14-hour increase in per streetlight outage time since 2022. MI-MAUI asserted that tracking streetlighting outages by the type of luminaire could pinpoint whether the increased outages were caused by a certain type of luminaire. MI-MAUI recommends that the Commission require Consumers to track outages by luminaire type so that the data gained may be used to reduce outage duration and frequency. MI-MAUI also requested that the Commission require Consumers to issue an annual standardized outage report. 4 Tr 2159, 3156; MI-MAUI's initial brief, pp. 13-16.

The ALJ recommended that the Commission direct Consumers to collaborate with MI-MAUI and the Staff to develop a standardized report format, delivery method, data protocols, and a streamlined outage report process in order to enhance efficiency and cost savings. The ALJ opined that the company currently tracks outages by the type of fixture and to now track outages by the type of luminaire would not be inordinately burdensome. PFD, p. 507.

In its exceptions, Consumers states that it made clear in its case presentation that the company does not have the ability to track outages by the type of luminaire. Consumers' exceptions, p. 169 (citing 4 Tr 2300). Additionally, Consumers argues that the record contains no evidence to establish that preparing the report described in the PFD would not be unduly burdensome as supposed by the ALJ. *Id.*, p. 170. Consumers also opines that tracking outages by luminaire type would be of limited benefit because it would not provide the reason for the outage and, in any case, tracking outages by cause would be burdensome. *Id*., p. 169 (citing 4 Tr 2300). Consumers points to the company's plan to convert its remaining high density discharge fixtures to LED luminaires within five years and, at that time, all streetlights will be LED luminaires. Consumers' exceptions, pp. 169-170. Finally, Consumers argues that the company does not have either the IT resources or the funding to fulfill the ALJ's recommendation, that obtaining needed resources would be neither cheap nor easy, and that no other customer group is provided a comparable annual report. *Id*., p. 170.

In its replies to exceptions, MI-MAUI argues that it is not burdensome for Consumers to note the type of luminaire when it investigates outages, particularly considering the decreasing streetlight reliability over the past couple of years. Although Consumers argues that no other company was required to provide the level of specificity as was suggested by the ALJ, MI-MAUI points out that in the December 1 order, DTE Electric was required "to work with stakeholders to develop a streetlight report request process, standardized report format, data protocols, and delivery method, as well as to update its streetlighting tariff to reflect the requirement to provide streetlight outage reports." MI MAUI's replies to exceptions, p. 2; *see*, *id*., pp. 1-2; *see also*, December 1 order, p. 373.

The Commission is not persuaded that working with the Staff and MI-MAUI to develop a standardized report or that reporting outages by the type of luminaire would be overly burdensome to the company. The Commission believes that discussions with the Staff and MI-MAUI may lead to solutions to the problems described by MI-MAUI in its case presentation, as well as solutions that would render such reporting to be far less difficult than anticipated by the company. Additionally, such discussions will provide MI-MAUI the opportunity to fully inform Consumers of the difficulties faced by streetlighting customers and the ways in which a report containing the suggested information would be helpful in easing those difficulties. Finally, reporting outages by a more granular metrics and developing the suggested report provides Consumers with the opportunity to meet the needs of its customers and to provide improved service, both of which are company goals. Accordingly, the Commission adopts the ALJ's recommendation for Consumers, the Staff, and MI-MAUI to work together to create a report as discussed in this order and for Consumers to develop the ability to report outages by luminaire type or other metrics deemed valuable during discussions.

3. Boat Slips

The Staff argued that a stand-alone case should be commenced within six months of the date of issuance of the decision in this case to fully evaluate whether additional tariffs are needed to offer residential rates, in some instances, to boat slips and marinas. The Staff testified that Consumers was previously directed to discuss how certain types of properties, such as boat slips, are classified for purposes of rate class eligibility.[27] The Staff argued that the criteria that is applied to seasonal condominium campgrounds, theoretically allowing them to be classified as residential, should also be applied to marinas and boat slips. 5 Tr 4037-4040.

Consumers opposed the Staff's recommendation, recounted the company's arguments from previous cases,[28] and affirmed that boat slips are classified as non-residential. The company argued that boat slips likely have fluid circumstances and that the administrative processes and

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[27] Consumers asserted there was a thorough discussion on the matter in Case No. U-21224; however, the case was resolved by a settlement agreement that did not include further discussion of classification of certain types of properties for rate eligibility. *See*, January 19 order.

[28] *See*, Case Nos. U-21224, U-20963, and U-20755.

costs to reevaluate the innumerable boat slips in its service territory for residential criteria would be burdensome. 4 Tr 659-660.

The ALJ opined that comparing seasonal campground condominiums with boat slips was not helpful because the applicable tariff appears to be written so that campground condominiums are always considered non-residential service. The tariff then points to other tariffs applicable to campers, boats, and yachts, all of which are classified as non-residential service and have no exception for residential classification even when they might have facilities considered necessary for a residence. Among other reasons, the ALJ pointed to the considerable administrative burden of reclassifying boat slips and individual boats, which generally serve recreational purposes rather than being long-lasting places of intentional dwelling. She also pointed out that reclassifying boat slips would likely benefit only a small number of customers. Accordingly, the ALJ recommended against a stand-alone proceeding in this instance. PFD, pp. 510-512.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation in this matter to be well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's recommendation for the reasons stated in the PFD.

4. Demand Response Recommendations

a. Updated Demand Response Credits for Next Electric Rate Case

The Staff recommended that the Commission should direct "Consumers to file an updated calculation of its DR credits in the Company's next rate case, which includes the latest estimate of CONE, [and] updated values of expected per-customer load reduction for credits that are administered monthly (e.g., the residential AC cycling program)[.]" PFD, p. 512 (citing Staff's initial brief, p. 179; 5 Tr 3671). The Staff requested that these calculations and values be based on actual figures whenever possible, rather than anticipated values. *Id*.

The ALJ noted that no party objected to the Staff's suggestion and considered the matter to be resolved. PFD, p. 512.

Therefore, the Commission adopts the Staff's recommendation for an updated DR credits calculation as discussed in this order to be submitted in Consumers' next electric rate case.

b. Miscellaneous Demand Response Suggestions

MEIBC/IEI/United proposed three changes to Consumers' DR tariffs to correct alleged anti-competitive language and policies and to improve the ability of offerings to meet individualized customer needs. MEIBC/IEI/United made these proposals in light of the Commission's December 21, 2022 order in Case Nos. U-21099 *et al*. that partially lifted the ban on aggregators of retail customers' (ARC's) development of DR resources. 5 Tr 3492.

First, MEIBC/IEI/United argued that Consumers should now be required to include in its DR tariff language and program materials whether customers considering participation in a particular Consumers' contractual or interruptible DR program are eligible or ineligible to participate in MISO's DR programs with an ARC. MEIBC/IEI/United asserted that Consumers' proposed changes to tariff wording on the issue fall short of providing clear eligibility information to customers. MEIBC/IEI/United pointed out that most, but not all, of Consumers' load modifying resources (LMRs) are registered with MISO and that customers enrolled with Consumers are not eligible to double-dip by also participating as part of an LMR with an ARC. If tariffs and other materials contained clear eligibility language, then customers may, perhaps, choose to enroll as part of an LMR with an ARC because customers would be informed prior to enrollment whether there are other opportunities for the customer to consider. 5 Tr 3493-3509.

Second, MEIBC/IEI/United proposed that Consumers unbundle its DR offerings. MEIBC/IEI/United argued that this will permit customers to make better use of various available DR programs without being limited by the receipt of bundled services from Consumers. Unbundled services and benefits would provide for competition from ARCs, as well as more opportunities for customers to pursue offerings that are tailored to their individual needs. MEIBC/IEI/United asserted that the changes stated above would likely lower customer costs by lowering administrative costs and costs to acquire customers while increasing load flexibility and customer participation in programs that are more suited to the customer's needs than currently available offerings. 5 Tr 3499-3509.

Third, MEIBC/IEI/United argued that Consumers could adopt "[a FIT] tariff that allows for DR aggregator participation and allows the utility to purchase ZRCs [zonal resource credits] registered with MISO towards meeting its Resource Adequacy Requirements as an LSE [load serving entity] in MISO, as well as satisfy its Capacity Demonstration requirements under Michigan law." 5 Tr 3509-3510. MEIBC/IEI/United requested that the Commission require Consumers to work with MEIBC/IEI/United to develop a DR FIT tariff model. 5 Tr 3510-3514.

Consumers disagreed that its DR programs are anticompetitive and stated that its DR customers are compensated based on the value of avoided capacity. Consumers generally opposed MEIBC/IEI/United's recommendations but stated that "[t]he Company is not averse to collaborating with DR aggregators to discuss the potential benefits of a DR FIT model proposal in a future electric rate case." 4 Tr 660, 2121-2122; Consumers' initial brief, p. 197.

The Staff agreed with MEIBC/IEI/United that a clarifying statement should be added to the DR tariff language. Staff's initial brief, p. 175. However, the Staff opposed MEIBC/IEI/United's other proposals as being either unclear or an emergent issue that requires more time to understand what response, if any, Consumers should make. The Staff also stated that a DR FIT tariff would be impractical because it would likely over- or under-compensate DR resources. *Id*., pp. 175-176.

The ALJ agreed with the Staff that MEIBC/IEI/United's proposals for unbundling DR tariff programs and development of a DR FIT tariff should be rejected at this time. However, the ALJ opined that the Commission desires further exploration of the issues related to the proposals and, accordingly, recommended that the Commission direct Consumers to participate in the workgroup established in the December 1 order, which stated:

> As such, the Commission directs the Staff to convene a workgroup to consider the following issues: (1) whether tying of retail and wholesale DR programs by the retail electric provider is appropriate; (2) whether a FIT or other tariff mechanism is needed or advantageous; (3) how Michigan's approach to DR aggregation comports with the frameworks being developed by PJM Interconnection, L.L.C., and MISO for compliance with Order 2222; and (4) any other related issues that the Staff finds appropriate to consider.

PFD, p. 520 (quoting December 1 order, p. 322); *see*, PFD, pp. 519-520.

In their exceptions, MEIBC/IEI/United reiterate their case presentation, arguing that their proposal would benefit customers and that the ALJ acknowledged the Commission's interest in such matters. MEIBC/IEI/United oppose participation in the workgroup and aver that the Commission should move ahead with the group's proposals, stating that the Commission could later "alter or reconsider the matters in a future proceeding." MEIBC/IEI/United's exceptions, pp. 7-8.

No replies to exceptions were filed.

The Commission finds the ALJ's recommendations to be well-reasoned and supported in the record. Accordingly, the Commission adopts the ALJ's recommendation to reject proposals for unbundling DR tariff programs and to develop a DR FIT tariff at this time for the reasons stated in the PFD. The Commission also adopts the ALJ's suggestion that Consumers participate in the workgroup established in the December 1 order as discussed above. Additionally, the

Commission directs Consumers to work with the Staff to develop language for the company's DR tariffs and related materials to clarify that customers may choose to enroll as part of an LMR with an ARC.

5. Other Rate Design and Tariff Issues

a. Transitioning Commercial General Service Rate Customers to a Time-of-Use Rate

In its previous electric rate case, Consumers proposed to close its commercial secondary flat energy-only Rate GS to new business, to gradually transition existing Rate GS customers to the company's new commercial secondary time-of-use (TOU) Rate GSTU, and to make this new rate the default assignment of new commercial customers. In the instant case, Consumers noted that the Staff had previously opposed the proposal, recommending that Consumers transition Rate GS customers immediately to a default TOU rate similar to the company's residential TOU rate. However, Consumers countered that the company could simplify rate GSTU thereby addressing the Staff's concerns. Finally, Consumers proposed that the company work with the Staff and interested persons to explore and pilot testing of "alternative communication and TOU rate designs structures to measure customer reactions." 3 Tr 204; *see*, 3 Tr 203-204; Consumers' initial brief, p. 435.

The ALJ noted that the Staff agreed with Consumers' proposal and considered the matter to be resolved. PFD, p. 521 (citing 5 Tr 3664).

The Commission finds that Consumers should work with the Staff and other interested persons to develop and pilot alternative communication and TOU rate design structures for secondary commercial customers.

b. Purchase of Excess Energy From Self-Generating Customers

Referring to behind-the-meter solar generation customers taking service under Consumers' General Service Primary Time-of-Use rate (Rate GPTU), ABATE recommended that the Commission direct Consumers to revise the Self-Generation, Net Metering, and Distributed Generation tariff, C11.1, Self Generation, Energy Purchase, that currently states "[t]he Company may discontinue purchases during system emergencies, maintenance, and other operational circumstances."[29] ABATE argued that Consumers should be obligated to make a payment for excess energy equal to MISO's real-time LMP for a maximum of 5 MW per meter of net output. ABATE's initial brief, pp. 59-61; 4 Tr 2747-2749. However, Consumers testified that it does purchase excess energy under Rate GPTU via contract but that the company must be able to refuse to purchase excess energy when conditions make this necessary. 3 Tr 221. Even so, ABATE continued to argue that there is no reason, other than a system emergency, maintenance, or other operational condition, that would justify the company's refusal to purchase excess energy from self-generating customers. ABATE's initial brief, p. 61.

The Staff testified that it did not take a position on whether ABATE's proposal is reasonable but asserted that Consumers should have the right to refuse to make excess energy purchases in cases where there is an outage, emergency, or other constraining event. 5 Tr 3680.

The ALJ acknowledged that Consumers must be permitted to refuse the purchase of excess energy when emergency circumstances make this necessary and, also, that ABATE is concerned that the tariff language does not provide sufficient protection for self-generation customers. The

[29] Rate GPTU refers customers to the Self-Generation, Net Metering and Distributed Generation, C11.1, Self Generation, Energy Purchase, for information on the purchase of excess energy.

ALJ recommended that Consumers and ABATE meet to discuss acceptable tariff language that addresses both parties' concerns to be submitted to the Commission within 60 days following the issuance date of the final order in this case. PFD, p. 523.

In its exceptions, Consumers states that it does not oppose meeting with ABATE but has no expectation that they will achieve a mutual understanding. The company argues its current tariff language provides needed flexibility. Consumers points out that ABATE did not point to any legal requirement for additional language nor to any instance in which Consumers had failed to contract with or refused to purchase excess energy from Rate GPTU customers. Consumers' exceptions, p. 171.

In its exceptions, the Staff states that it should be included in the discussions if the Commission orders ABATE and Consumers to discuss tariff language regarding the purchase of excess energy from Rate GPTU customers. Staff's exceptions, pp. 6-7.

In its replies to exceptions, the Staff reiterates that Consumers should have the ability to refrain from the purchase of excess energy in emergencies. Staff's replies to exceptions, p. 26.

In its replies to exceptions, Consumers reiterates that it does not oppose meeting with ABATE or the Staff being involved but the company does not believe the discussions will result in an agreement between the company and ABATE. Consumers' replies to exceptions, p. 117.

The Commission finds that the ALJ's recommendations on this matter are well-reasoned and supported in the record. Accordingly, the Commission adopts the ALJ's recommendations for the reasons stated in the PFD.

c. Alignment of General Service Primary Time-of-Use Rate and Energy Intensive Program Rate's Mid- and High-Peak Hours

ABATE recommended that Rate GPTU's mid- and high-peak hours should be aligned with Rate EIP's mid- and high-peak hours because Rate GPTU's periods are too long, are inconsistent with Consumers' system peaks, and may not properly incentivize customers to shift load to another period. ABATE's initial brief, pp. 61-63.

The ALJ found that peak hours for Rate EIP and Rate GPTU should match and that the evidence on the record is sufficient to establish that a seven-hour peak is too long. PFD, p. 525.

In its exceptions, Consumers opposes aligning Rate EIP and Rate GPTU mid- and high-peak hours and requests that the company be permitted to address the matter in its next electric rate case. If the Commission finds that the alignment should take place, Consumers states that it needs at least six months to properly enact the change. Consumers' exceptions, pp. 171-172.

In its replies to exceptions, ABATE reiterates that the evidence of record is sufficient for a finding to align the rates as proposed. ABATE's replies to exceptions, pp. 14-15.

The Commission finds that the ALJ's recommendations on this matter are well-reasoned and supported in the record. Accordingly, the Commission adopts the ALJ's recommendations for the reasons stated in the PFD. The Commission directs Consumers to implement this change within six months of the date of issuance of this order.

IX. OTHER ISSUES

A. Investment Recovery Mechanism

To further the company's commitment toward the reliability and resilience of its electric distribution system, Consumers proposed an IRM as follows:

> The Company's proposed IRM would provide for the recovery of capital programs that are critical for distribution system reliability, while providing customer protections and additional opportunities for collaboration and review. 3 TR 103. All of the investments included in the proposed IRM will have the effect of hardening the system against severe weather and/or limiting the number or duration of customer interruptions when an incident on the distribution system occurs. And with fewer and shorter interruptions when severe weather hits the system, there will be fewer MEDs [major event days]. 3 TR 103; 4 TR 400-401.

> The investments included in the proposed IRM consist of the following sub-programs:
>
> > • *LVD Lines Reliability*, excluding Circuit Exit Enhancements and ROW [right-of-way]/Easement Procurement;
> >
> > • *Resiliency*, excluding Overhead to Underground;
> >
> > • *Automation*, excluding DSCADA, Line Sensors, Voltage Regulator Controllers, and Capacitor Upgrades;
> >
> > • *HVD Lines Reliability*; and
> >
> > • *System Protection*.
>
> These investments would total $100,770,000 in the test year. 3 TR 106; 4 TR 401.
>
> The IRM would cover a three-year period, going into effect at the beginning of the test year and continuing through the end of February 2027, or until base rates are reset in a future rate case. 3 TR 103-104. The IRM's revenue requirements would be collected through a surcharge. 3 TR 103.

Consumers' initial brief, pp. 443-444 (emphasis in original). Consumers further provided that:

> the Company would hold Year 2 and Year 3 IRM investment levels consistent with the test year IRM amounts. While in the future the Company may need to increase annual investments in these programs, the Company proposes to keep the annual investment level capped at test year levels for the purposes of this initial IRM. 3 TR 106.
>
> The IRM will provide multiple benefits to customers and stakeholders. 3 TR 103. Customers will benefit from the certainty of investments in the capital programs included in the IRM that are critical to improved reliability. And the IRM will bring additional transparency and accountability to project planning and results through reconciliation filings, collaboration on IRM project planning, and reporting on the execution of those plans. 3 TR 104.

Consumers' initial brief, pp. 444-445. Notably, the company also agreed during rebuttal to some revisions from the Staff and Walmart regarding transparency concerns with IRM planning meetings, demand-based charges for rate schedules with demand-based rates, and reconciling revenues generated by each customer class through the IRM surcharge. 3 Tr 116-117; Consumers' initial brief, pp. 445, 447-449.

The Staff supported the IRM as modified in rebuttal, reasoning that an IRM will assist in ensuring that approved spending on distribution system improvements will be spent on those investments. 5 Tr 4085-4086; Staff's initial brief, pp. 147-150. The Staff, however, maintained its recommended downward adjustment of $15,842,000 for the IRM based on overall recommended test year capital expenditure reductions from HVD capital programs (specifically, the company's HVD Lines Reliability and System Protection programs). 5 Tr 4085-4086; Staff's initial brief, p. 149. The Attorney General, ABATE, Walmart, UCC, the CEOs, GLREA, and MNSC, on the other hand, opposed the IRM as unnecessary, among various other reasons. Consumers disagreed with the intervenors, dismissing their arguments as being without merit. Consumers' initial brief, pp. 451-454.

The ALJ agreed with the intervenors and concluded that the IRM should be rejected for three principal reasons:

> First, this [ALJ] agrees with the Attorney General and the CEO that approving IRM spending before projects are planned, then undertaking a prudency review post-investment is problematic given the reluctance to disallow investment capital spending once incurred. Second, the [ALJ] agrees with the UCC and MNSC, that that [sic] the "metrics" the company proposes to report are more in the line of program accomplishments (e.g., X number of miles of LVD lines replaced; Y number of substations rebuilt) rather than actual reliability metrics like reductions in SAIDI, SAIFI [system average interruption frequency index], or MEDs. Lastly, this [ALJ] is as mystified as many of the intervenors are about the purported need for an IRM. As Walmart, the Attorney General, and ABATE point out, Consumers is in the habit of filing annual rate cases, which in turn present a yearly opportunity to propose, and have reviewed, spending on resiliency and reliability programs without the need for an additional reconciliation proceeding. While Consumers makes much of the fact that with the IRM, the company will be required to spend on specific distribution programs, there is nothing in the normal rate case process that prevents the company from requesting reliability capital expenditures, and then following through by actually spending the approved amounts on those programs.

PFD, pp. 532-533.

The Staff disagrees with the ALJ's analysis and maintains that the Commission should approve the company's IRM with the Staff's modifications, consistent with the Staff's recommendation in Case No. U-21297. The Staff reiterates that "[a]n IRM will help ensure that approved spending on distribution system investments is spent on those investments." Staff's exceptions, p. 8.

Consumers, too, disagrees with the ALJ and argues that the ALJ's analysis failed to mention that the Commission recently approved an IRM for DTE Electric in Case No. U-21297, a similar mechanism as proposed by Consumers with similar arguments raised by the intervenors in the instant case. Following a recap of the details of its proposed IRM, Consumers rebukes the ALJ's conclusions by stating:

> [c]ontrary to the [ALJ]'s conclusions, the IRM reconciliation provides for a process that allows for full scrutiny of the capital expenditures. The reconciliation would also provide an opportunity to review the results of the reporting metrics for the IRM programs, and to address any concerns with actual capital dollars spent. 3 TR 109. Through a contested case proceeding, the IRM reconciliation will compare the IRM capital spending that the Company used in the calculation of the surcharge for the applicable IRM period to the actual capital spending by program. If the Company did not spend the full amount of capital, it would refund to customers the revenue requirement of the difference in the capital spending. 3 TR 110-111, 210-211. Additionally, the IRM reconciliation would include a comparison of reporting metric targets to actual achievements. The Company's filing would explain deviations between the plan and actual spending and target metrics and achievements. Notably, the Company would reconcile each program included in the IRM and would not shift spending between the programs. *Id*.
>
> While the [ALJ] expressed concern with the Company's proposed reporting metrics, the concerns expressed overlooked the purpose of the proposed metrics. The proposed IRM metrics is to ensure that the Company completes the planned amount of work for the stated investment level. 4 TR 477. The IRM is premised on the Company investing a certain dollar amount in certain investment categories, with refunds owed to customers if the Company does not do so. The proposed metrics ensure that the Company does not simply find the most expensive projects and complete them in order to hit spending targets, and they further encourage the Company to stay on budget for the selected projects and to complete them on time.

Consumers' exceptions, pp. 151-152. The company avers that its identified IRM investments are critical for the reliability and resiliency of its distribution system and that such investments warrant further transparency and accountability that the proposed IRM would provide, with benefits of the proposed IRM acknowledged by the Staff. Consumers further states that its proposal is aligned with the Commission's recent guidance on pages 76-77 of the November 18 order. In sum, per Consumers:

> The Company's proposed IRM ensures that approved spending on critical investments is spent on those investments. The reconciliation process and the Company's commitment to reconcile by line item provides a strong incentive for the Company to complete the IRM spending as included in the IRM surcharge and not shift dollars between programs. These demonstrated benefits will be realized even if rate cases are filed annually.

Consumers' exceptions, p. 152.

UCC conversely applauds the ALJ's rejection of the company's proposed IRM. UCC's exceptions, p. 1.

In replies to exceptions, Consumers expresses appreciation for the Staff's support regarding approval of its proposed IRM and reiterates the company's agreement to proposed modifications set forth by the Staff and other intervenors, just not Staff's proposed downward adjustment to IRM spending. Consumers maintains that its "spending amounts are reasonable and the identified IRM investments are critical for distribution system reliability and resiliency." Consumers' replies to exceptions, p. 74.

MNSC argues that the company's IRM should be disapproved, highlighting that the Commission did not invite Consumers to propose an IRM in this case like it did for DTE Electric in Case No. U-20836 and noting also the Commission's disapproval of the company's prior IRM proposals in Case Nos. U-17735 and U-17990. MNSC further argues that the ALJ thoroughly analyzed this issue and presented compelling reasons to deny the IRM, which the Commission should uphold on all counts but also because the company has not shown that the IRM will benefit customers. MNSC recaps the company's proposal, the company's agreement to some but not all of the Staff's recommendations, and the united opposition to the IRM from other intervenors and then expands on its response to the company's and the Staff's exceptions, refuting their claims. MNSC's replies to exceptions, pp. 56-72. MNSC argues:

> In sum, the IRM is a flawed and unnecessary proposal that does not benefit customers and that the Commission did not ask Consumers to make. The [ALJ] thoroughly evaluated the evidence and recommended that the Commission deny approval of the IRM. The Commission should uphold the PFD and reject this proposal.

Id., p. 72.

The CEOs assert that the ALJ correctly rejected the IRM and that the Commission should do the same. The CEOs state that the ALJ "astutely observed [that] an IRM has little value when the Company returns to the Commission for rate increases annually" and reiterate that an IRM will introduce a lower level of scrutiny, with the potential of IRM projects being given a presumption of just and reasonableness by the Commission because investments had already occurred. CEOs' replies to exceptions, p. 1 (citing PFD, p. 533; 4 Tr 3248; CEOs' initial brief, p. 26). The CEOs, in this regard, agree with the Attorney General's witness that "'there is virtually nothing appealing about the proposed IRM. Most importantly, it is not needed.'" CEOs' replies to exceptions, p. 1 (quoting 4 Tr 2999).

The Attorney General argues that just because an IRM was approved for DTE Electric does not mean it is appropriate for this case, that the existing rate case process which Consumers avails itself to yearly already provides for recovery of programs that are critical for the distribution system while providing customer protections, that the company's claims about fewer MEDs are unsupported other than by way of vague claims that the IRM will lead to fewer and shorter interruptions when severe weather hits, and that the scope of review is different in a reconciliation versus a rate case, arguing that higher costs are passed on to customers with less scrutiny via reconciliation. Attorney General's replies to exceptions, pp. 86-87. The Attorney General asserts that "[t]he proposed IRM is not needed," as "[t]he Company has not demonstrated that it is hurting financially from any lack of cost recovery pertaining to capital expenditures included in the IRM or that it is not able to recover the same capital investments in a general rate case." *Id*., p. 87.

UCC asserts that the exceptions provided by Consumers and the Staff lack merit and rehash arguments that have already been refuted by UCC and other intervenors. More specifically, UCC argues that Consumers trivializes concerns raised by intervenors about accountability and transparency, that the company improperly assumes that its IRM should be approved just because one was approved for DTE Electric in Case No. U-21297 (on a record unclear as to whether concerns about post-investment prudency review and affordability challenges were considered), and that the Staff's exceptions are unresponsive to the PFD and do not support the IRM being necessary. UCC's replies to exceptions, p. 6; *see also*, *id*., pp. 7-13. UCC also questions how equity would be addressed in a contested reconciliation case with Consumers given the company's "stated reticence to provide the data necessary to make equity determinations." *Id*., p. 10. If the Commission, however, approves the IRM in this case, UCC requests that the Commission answer the following questions:

1. What is the exact approach that the Commission is proposing to use in the contested reconciliation proceeding to assess the equity of the IRM investments?

2. Does the Commission support requiring the Company to provide information—whether as part of the Company's reconciliation filing or through discovery—that would allow Intervenors, the ALJ, and the Commission to assess accurately the equity impacts of the investments made through the IRM?

> 3. Does the Commission agree with UCC that differential impacts or "racialized disparities in service" resulting from or perpetuated by new grid investments should bear on the question of whether the Company's expenditures were reasonable and prudent and whether the Company should be able to recover on those investments after they have been made?
>
> 4. Is the Commission willing to disallow recovery for investments made through the IRM during the reconciliation process on the basis that the Company's investments exacerbate or perpetuate racial or socioeconomic disparities in service or are otherwise inequitable, even after the Company has already incurred the cost of these investments?
>
> If not, how can the contested reconciliation serve the Commission's stated goal of assessing "equity concerns?" Given the lack of clarity on how equity can be reviewed in a reconciliation proceeding, UCC is concerned that Intervenors' "input" on equity issues during the reconciliation process, after the IRM has been approved and expenditures have been made, will neither be able to impact the direction of the Company's investments nor protect ratepayers from the imprudence of such investments. If the Intervenors do not have a meaningful opportunity to address disparities resulting from the Company's investments during reconciliation, then the reconciliation process will not provide even fleeting lip-service to Intervenors' equity concerns.

Id., pp. 11-12.

ABATE maintains that the Commission should not approve the proposed IRM, arguing that Consumers' claims in exceptions do not address the flaws of the company's proposal. Specifically, ABATE asserts that the reconciliation process discussed by the company does not rectify the problem of undertaking a prudency review post-investment and the reluctance to disallow capital spend once incurred but rather "embodies it." ABATE's replies to exceptions, p. 12. ABATE argues that the company's claim about performance metrics is "similarly unsupportive," stating that "if the Company is apparently willing to track this data, it could simply file an annual report with the Commission to assess the execution of the Company's investment plans approved in this rate case, or include such a report along with its rate case applications." *Id*. Thus, per ABATE, "[t]he proposed IRM is neither necessary nor a reasonable approach to accomplish what Consumers could otherwise do of its own accord." *Id*. ABATE further argues, in response to the Staff's claims, that meetings in advance of an IRM period will not address or rectify the proposed IRM's myriad deficiencies as identified by the ALJ and that the rate case process already allows for a way to ensure approved spending on distribution system investments are spent on those investments by way of future adjustments to cost projections, considering past discrepancies between planned and actual spending. In sum, as set forth by ABATE:

> Given its deficiencies and the lack of necessity for the proposed IRM the Company's proposal should be rejected. Further, cost recovery for these distribution system investments should be based on historical expenses to avoid over-recovery. If, however, the Commission approves an IRM it must ensure the IRM revenue requirement calculation reflects depreciation expense for similar plant included in base rates as an offset to the incremental IRM plant investment for the purpose of calculating a return on IRM investment[.]

Id., p. 13.

Considering crosscutting concerns over safety and reliability impacting Consumers' electric distribution system, the Commission finds it reasonable and prudent to partially approve the company's request for an IRM with agreed-upon IRM process modifications (regarding planning meetings, demand-based charges, and contested reconciliations) and as modified by the Commission in this order. *See*, Consumers' initial brief, pp. 445-449; *see also*, e.g., Case No. U-21305. With specific consideration for safety and reliability in making this determination, the Commission accordingly finds the capital programs for LVD Lines Reliability, excluding Circuit Exit Enhancements and ROW/Easement Procurement; Resiliency, excluding Overhead to Underground; and System Protection to be reasonable and prudent for inclusion in the IRM, with IRM approval for two years, as opposed to three, to allow time for the IRM to move forward but for reevaluation to take place as to whether the IRM should continue beyond Year 2. This review of whether the IRM should continue will consider how the concerns raised by UCC, MNSC, the CEOs, the Attorney General, and others are addressed and whether they outweigh the benefits of the IRM. In this review, the Commission will consider, among other things, evidence presented on whether the investments are, in fact, being deployed equitably, whether the investments exacerbate or perpetuate racial or socioeconomic disparities in service, whether there has been a positive impact on reliability and resilience, whether there is sufficient opportunity for scrutiny of the investments, and whether customers have benefitted from the IRM mechanism. Insights from the audit in Case No. U-21305, along with other ongoing cases, will also be informative and may lead to further changes. And with the capital programs involving HVD Lines Reliability and Automation, excluding DSCADA, Line Sensors, Voltage Regulator Controllers, and Capacitor Upgrades, the Commission finds the standard rate case process to be the appropriate forum to continue vetting such investments for reasonableness and prudence at this time. The Commission thus, consistent with capital expenditure decisions made earlier in this order, approves the following capital spend amounts to be included in the IRM in this case:

Capital Program	**IRM Year 1 (12 months ending 2/28/25)**	**IRM Year 2 (12 months ending 2/28/26)**
Lines Reliability – LVD	$36,880,000	$36,880,000
Resiliency	$8,973,000	$8,973,000
System Protection	$3,473,000	$3,473,000
Totals	**$49,326,000**	**$49,326,000**

Equity considerations are addressed directly below.

B. Environmental Justice, Grid Equity, and Affordability

1. Grid Equity

Consumers acknowledged its commitment in the settlement agreement in Case No. U-21224 that in future distribution plans and rate cases the company would analyze reliability performance and hosting capacity for EJ communities. The company further described the EJ and grid equity work the company has done so far and is planning to do moving forward. 3 Tr 131-134; 4 Tr 385-386; Consumers' initial brief, pp. 454-458. The Staff, the CEOs, and UCC weighed in and provided several recommendations going forward. Staff's initial brief, pp. 150-170; CEOs' initial brief, pp. 5-25; UCC's initial brief, pp. 28-41. Consumers responded. Consumers' initial brief, pp. 458-468; Consumers' reply brief, pp. 72-76.

The ALJ found insufficient evidence to conclude that Consumers failed to comply with the commitments it made in the settlement agreement in Case No. U-21224. The ALJ summarized the Staff's recommendations as follows and found that Consumers "acquiesced" to Staff's points 3, 4, 5, and 7:

> (1) a request that the Commission require Consumers to provide additional information in future rate case filings as explained by [Staff witness] Dr. Wang, including reliability metrics associated with EJ screening scores in 5-percentile-increments; (2) a request that the Commission explore the minimum reliability expectations that should be set, to consider both below-average reliability metrics and high restoration costs; (3) a request that the Commission require additional information regarding wires down as explained by Dr. Wang; (4) a request that the Commission require Consumers, Staff, and stakeholders to evaluate cooling season disconnection protections or other pathways to prevent heat-related illnesses and death in Michigan as global temperatures increase; (5) a request that the Commission require Consumers to develop a pilot in conjunction with a third party that could tap into available funding to promote the installation of household EWR [energy waste reduction], solar, and storage to provide a source of protection for medically vulnerable residents; (6) a request that the Commission require Consumers to include climate resiliency planning in future distribution plans, with a 50-to-100-year time horizon; (7) a further request that the Commission request the company to explain its consideration of EJ and equity issues in its next rate case and foster additional stakeholder engagement as explained by [Staff witness] Ms. Schiller; (8) a request that the Commission establish additional standards for distribution planning; and (9) a request that the Commission develop a standardized process for Staff and intervenors to request, safely obtain, and use GIS [geographic information system] data. Staff also cites [Staff witness] Mr. Isakson's testimony in arguing that the Commission should not rely on the output of [CEO witness] Mr. Tan's statistical analysis.

PFD, pp. 550-551 (footnotes omitted); *see also*, PFD, pp. 558-559,[30] and Staff's initial brief, pp. 150-170.

The ALJ found that, while Consumers and the Staff agree that additional, more formalized standards for distribution planning are desirable, the Staff's request from point 2 that the Commission explore minimum reliability expectations (to consider both below-average reliability metrics and high restoration costs) should be addressed in Case No. U-20147, along with Staff's recommended 50-to-100-year time horizon for climate resiliency planning in future distribution plans from point 6. PFD, p. 559.

Lastly, with regard to recommendations from the Staff (points 1 and 9), the CEOs, and UCC on additional data, metrics, mapping, and regression analysis requests, the ALJ stated:

> Consumers is generally willing to make the information available, but considers it to be a burden, and objects as a matter of principle to ad hoc requests regarding its rate case filing that are not incorporated into the filing requirements applicable to all utilities. While this [ALJ] generally finds it reasonable to ensure that the parties have access to the information they need in a timely manner, this [ALJ] encourages the parties to confer prior to the company's next rate [case] filing to clarify and preferably consolidate the data requests into a manageable list for the company, based on an understanding of the limits on the available data. Also, this [ALJ] recommends that until the results of additional equity analyses are reviewed, that the Commission not require the provision of the requested information on an ongoing basis, i.e., applicable to all future filings, but only to the company's next rate case filing.
>
> Finally, this [ALJ] notes the CEO's request that the company be required to undertake regression analysis. Consistent with the Commission's determination in its December 1, 2023 order in Case No. U-21297 not to require DTE Electric to perform regression analysis as part of its evaluation of grid equity, this [ALJ] similarly finds that there would be little value in requiring Consumers to undertake an analysis it does not find useful.

[30] The ALJ considered Staff's point 7 here to essentially be the same request from the CEOs for Consumers to provide a more comprehensive explanation as to how the company incorporates the results of its EJ analysis into its grid investment decisions. PFD, p. 559.

PFD, p. 560 (footnote omitted).

The CEOs object to the ALJ's rejection of their regression analysis recommendation for two reasons. First, the CEOs assert that the ALJ misread the December 1 order, which they assert "could simply be a result of several missing words on page 352 of the Commission order, which the PFD cites to." CEOs' exceptions, p. 2. More specifically, the CEOs state that page 352 of the December 1 order should read, as confirmed by pages 375-376 of the order, that DTE Electric is directed to "'work with the Staff and other stakeholders to develop a detailed [*regression analysis*] of customer demographics and reliability for vulnerable customers to be used in the company's distribution plan case, and orders DTE Electric to provide the data supporting their regression analyses that will allow interested parties to perform their own analyses.'" CEOs' exceptions, pp. 2-3 (citing December 1 order, p. 352) (alteration and emphasis in exceptions). The CEOs thus argue that the December 1 order "does the exact opposite of what the [ALJ] claims." CEOs' exceptions, p. 3. Second, and despite the first reason, the CEOs assert that the ALJ applied the wrong standard in determining that Consumers should not perform a regression analysis, as "what the Company 'finds useful' is not the relevant standard in determining what type of evidence it must bring to bear in a rate case, nor is it the standard in determining whether rates are just and reasonable." *Id*. Rather, per the CEOs, "[t]he Company must provide '[thorough], detailed, and meaningful' evidence in order for the Commission to approve a rate increase," and "[w]ithout a clear basis for understanding differential reliability in the Company's territory, the Commission cannot determine whether the company's spending proposals are just and reasonable." *Id*. (citing June 7, 2012 order in Case No. U-16794, p. 13). The CEOs thus contend that "[t]he Commission should conclude that in order for the Company to properly support its case regarding reliability investments in the distribution system, the Company must properly account for differential reliability experiences using granular statistical analysis like regression analysis." CEOs' exceptions, pp. 3-4.

Beyond regression analysis, the CEOs also assert that the PFD is unclear about future equity analysis. More specifically, the CEOs are unclear about what is recommended by the ALJ when she recommends that "'until the results of additional equity analyses are reviewed, that the Commission not require the provision of the requested information on an ongoing basis, i.e., applicable to all future filings, but only to the company's next rate case filing.'" *Id*., p. 4 (citing PFD, p. 560). The CEOs question and state:

> Does this mean that the Company provide the type of analysis requested by Staff Witness Wang in only the next case or not at all? The CEO support Staff Witness Wang's recommendation, and believe that, in general, the Company's simplistic analysis of EJ reliability v. systemwide reliability lacks the necessary detail to be useful. *See* CEO Opening Br. at 23-24. To the extent that the [ALJ] fails to order a more searching analysis of differential reliability, the CEO take exception. The Commission should clarify this unclear aspect of the PFD and decisively order the Company to undertake a more rigorous and granular analysis that delves deeper than the Company's rudimentary systemwide scope.

CEOs' exceptions, p. 4.

Consumers contrastingly appreciates the ALJ's recognition of the company's concern about imposing additional burdensome filing requirements on it. Consumers states:

> As the [ALJ] suggests, the Company can meet with the parties to help clarify the limits of data that is readily available. If the parties desire such a meeting, it should be for the purpose of developing an understanding of what the Company is able to provide during the rate case discovery process and not to establish additional rate case filing requirements that apply only to Consumers Energy. The Commission has already initiated a process in Case No. U-21122 to address utility reporting of additional information pertaining to distribution system reliability, customer outages, and storm response and to develop a Commission webpage to display the latest information related to distribution reliability. See [Commission] Case No. U-21122, March 3, 2022 Order, page 83. The Commission should not impose additional distribution-related rate case filing requirements that apply just to Consumers Energy in this case. 4 TR 476.

Consumers' exceptions, pp. 155-156.

UCC argues that the Commission should clarify and partially reject some of the ALJ's findings regarding environmental justice in the PFD. First, while the ALJ seemed generally receptive to data requests from intervenors, UCC contends that the ALJ's recommendation regarding UCC's specific information requests is ambiguous. More specifically:

> The [ALJ] recommended that, "until the results of additional equity analyses are reviewed, [] the Commission not require the provision of the requested information on an ongoing basis, i.e., applicable to all future filings, but only to the company's next rate case filing." There seem to be three potential interpretations of this recommendation. First, one may interpret the [ALJ] as recommending that the Commission reject the information requests of the Intervenors. Second, the [ALJ] may have declined to make a recommendation on UCC's specific requests for additional information. Third, the [ALJ] may be suggesting that the Company should be required to confer the requested information in its next rate case, with a recommendation to Intervenors that those requests are provided as a list near the start of the next rate case. Regardless of the ambiguity of the [ALJ]'s recommendations, UCC requests that the Commission require Consumers to provide UCC's requested data in the Company's next rate case.

UCC's exceptions, p. 3 (footnote omitted; second alteration in original). UCC addresses each of these interpretations in greater detail, ultimately asserting the benefits that its data request on customers experiencing multiple interruptions (CEMI) and customers experiencing long interruption data (CELID) would provide in terms of inequities in energy reliability and outages within Consumers' service territory, with little additional burden on the company to provide. Per UCC, "[t]he combination of these metrics would provide additional context for the Company's EJ analyses, helping to target communities that suffer from the most frequent and longest outages." *Id*. Thus, to the extent the ALJ's recommendation is interpreted to mean that the Commission should require the provision of UCC's requested information during the Company's next rate case, UCC agrees, stating its "general[ ] willing[ness] to meet with other intervenors to, 'clarify and preferably consolidate the data requests into a manageable list for the company'" but also requesting that "the Commission provide additional guidance on this recommendation and clarify how this consolidated data request will be enforced against the Company." *Id*., p. 5 (quoting PFD, p. 560).

Second, UCC contends that the Commission should require Consumers to conduct an EJ analysis that compares reliability in similarly situated communities. UCC asserts that the ALJ made no direct findings or recommendations related to this request. While the ALJ's recommendations do reference additional equity analyses, UCC argues that such reference is unclear. More precisely:

> First, the [ALJ]'s recommendation does not specifically point to what equity analyses are ongoing. More importantly, the Company has already provided an "equity analysis" in this case. Indeed, the Company's equity analysis provided in this case appears to be used as support for the requested approval of a number of the Company's investments and will likely continue to be used to support approval of the Company's distribution grid investments in the next rate case. To the extent the ALJ is suggesting that better analysis is forthcoming, and that the Company's equity analysis in this case was insufficient, the Commission should not reject UCC's request to improve this analysis with additional data. As such, the Commission should require the Company to improve upon its EJ analysis, both by providing additional data, and by requiring an improved EJ analysis that will more accurately reflect inequities within the Company's service territory.

UCC's exceptions, pp. 6-7 (footnotes omitted).

Third, UCC asserts that the Commission should reject the ALJ's recommendation that distribution planning concerns be moved directly to Case No. U-20147. With this objection, UCC argues that the ALJ's failure to engage with its arguments regarding Consumers' distribution plan, as well as the recommendation to move general issues concerning distribution planning to Case No. U-20147, are unreasonable and should be rejected for three reasons: "(1) [Case No.] U-20147 is an uncontested case where the ability to both challenge and influence the utility's decisions is limited, (2) funding for the distribution plan is reliant on this and future rate cases, and (3) the Company itself has relied on its distribution plan to justify its rate proposals." UCC's exceptions,

p. 7; *see also*, *id*., pp. 7-9. In this regard, UCC requests that the Commission find that considering distribution investment concerns in a rate case is appropriate.

Fourth, UCC argues that there is ample evidence to suggest that Consumers failed to make its best efforts to account for EJ in its distribution planning as required pursuant to the settlement agreement in Case No. U-21224 and that it is unclear how the ALJ decided otherwise. More specifically:

> [I]n Consumers' initial filing, Witness Kelly acknowledged that the Company could do more to consider environmental justice and was considering other statistics to include in future versions of its EDIIP [electric distribution infrastructure investment plan], including studying, "reliability performance and hosting capacity on circuits that overlap with EJ communities." However, the Company's EJ analysis only evaluated differences between EJ and non-EJ communities generally and did not analyze how EJ status affects customers when accounting for key community characteristics. As such, the Company's assessment likely provided misleading information about the differences in reliability between EJ and non-EJ communities.
>
> Other evidence suggests that the Company lacked basic knowledge about its own EJ assessments. After confirming that he was the best Company witness to address EJ issues within the distribution system, Witness Kelly admitted that he did not know why the Company provides separate grid archetypes for rural and urban customers, nor could he explain why this bifurcation is useful. Similarly, Witness Kelly did not know whether the Company had analyzed what percentage of EJ communities fell within each of the archetypes. If these statements are correct, then the Company appears to not have effectively incorporated any EJ considerations into its Grid Archetype analysis, which seems to be a primary mechanism for ensuring equitable investment in its distribution infrastructure.
>
> Because the Company lacked knowledge about its EJ assessments, it has jumped to dubious conclusions. For example, when questioned about CEMI and CELID metrics, Witness Kelly stated that the Company had not included these metrics in its EJ analysis, noting potential resource constraints. However, when questioned further about CELID, Witness Kelly admitted that he could neither explain what this metric measures, nor did he know whether the Company currently tracked this data. The Company must already track much of this data for other purposes, such as for distributing outage credits. Curiously, the Company did not address these points in its Reply Brief. If the Company assumed that analyzing CELID would constrain resources without even attempting to learn what CELID measures are and whether it already tracks such data, it is unclear how this could possibly constitute its "best effort."

UCC's exceptions, pp. 10-11 (footnotes omitted). In short, according to UCC:

> the Company cannot just put forth "any effort" and call it its "best." Here, the evidence suggests the Company knew it could improve its EJ assessments, lacked basic knowledge about its own EJ assessment, failed to fully consider reviewing additional reliability metrics, and as result, produced what is likely a misleading assessment. To ensure the Company meets its obligations under its settlement agreement, the Commission should order the Company to provide new metrics that better capture the disparity in reliability between EJ and non-EJ communities. Specifically, UCC requests that the Commission require the Company to track and regularly provide CEMI and CELID in addition to the other reliability metrics the Company currently tracks and shares, and to provide additional analysis of reliability comparing EJ communities and similarly situated non-EJ communities.

UCC's exceptions, p. 11.

In replies to exceptions, Consumers first addresses the CEOs' exceptions as to the request for additional grid equity analysis and maintains that such additional analysis is neither necessary nor cost-effective. Consumers states:

> The SAIDI statistics that the Company provided in this case reflect the reliability that is occurring on the Company's distribution system, and the Company is already performing a granular review of this data by considering SAIDI by census tract. This analysis allows the Company to identify the reliability of a given area of its system and identify solutions when that area has reliability issues.

Consumers' replies to exceptions, pp. 102-103 (citing 4 Tr 473). Consumers recaps the CEOs' data assertions but states that "[i]t is not clear why the number of census tracts in EJ communities compared with non-EJ communities would skew the data because the method by which SAIDI is calculated already accounts for the number of customers in a given population." Consumers' replies to exceptions, p. 103 (citing 4 Tr 473). Consumers further states, "[w]hile it is true that densely populated circuits tend to have better reliability, it is not clear why that is a problem that requires additional analysis." Consumers' replies to exceptions, p. 103 (citing 4 Tr 473). Moreover, according to Consumers:

> the Company already considers the independent variables that were used in CEO's regression analyses in the Company's distribution planning without the need for complex modeling. Population density is featured in the Company's Grid Archetypes; characteristics such as median income will be considered in distribution planning as the Company includes EJ status in its Grid Archetypes going forward; and the MiEJScreen tool provides an appropriate means for identifying vulnerable communities without creating new models based on individual demographic data points.

Consumers' replies to exceptions, p. 104 (citing 4 Tr 474). Consumers further distinguishes its service territory from Detroit and Chicago, reiterates that the data analysis that the CEOs recommend requires skilled personnel and software applications, and asserts a lack of demonstration by the CEOs and the Staff as to why reliability analysis in 5% intervals of MiEJ Screen percentiles is necessary. Consumers thus maintains that there is a lack of demonstrated usefulness of this information and that the same should thus be rejected, allowing the EAAC process to continue bringing together a wide variety of interested persons on these issues instead. Consumers' replies to exceptions, pp. 104-105 (citing 4 Tr 478-479).

As to UCC's additional information requests, Consumers responds, with regard to CEMI and CELID data, that it:

> continues to have concerns with having the available resources to collate more data and produce more interactive maps in providing this data. 4 TR 476. The Company will continue to provide reasonably available information to the parties through the rate case and discovery process as it did in this case, but the Commission should not make additional rate case filing requirements that apply just to Consumers Energy. *Id*. Regarding UCC's request to require the Company to compare reliability performance of EJ communities to only those non-EJ communities with similar characteristics, UCC has not demonstrated what value this comparison would provide. As discussed, the Company has already presented data showing good reliability performance in EJ communities. 4 TR 476-477.

Consumers' replies to exceptions, p. 106. Consumers further disputes that its analysis is likely misleading, stating:

> As discussed, the analysis performed by the Company indicates that EJ census tracts experienced better reliability in 2020 through 2022 than the system as a

> whole and better than non-EJ census tracts, whether considering SAIDI, SAIFI, or CAIDI and whether including or excluding MEDs. 4 TR 466. This data represents the actual frequency and duration of outages experienced by customers, and the Company's focus on census tracts indicates whether those communities are experiencing reliable electric service. *Id*. The Company's analysis of the SAIDI, SAIFI, and CAIDI experienced in EJ communities is a proper analysis of reliability in those communities.

Consumers' replies to exceptions, pp. 106-107. And as to UCC's best efforts arguments, Consumers states:

> The Settlement Agreement in Case No. U-21224, paragraph 23.g, states: "While the Company may not be able to fully implement changes in its business processes and tools by the next rate case, the Company will make best efforts to consider equity in its distribution system planning in the next rate case . . . ." UCC challenges whether the Company used "best efforts" under the Settlement Agreement in part because of UCC's argument that "the evidence suggests the Company knew it could improve its EJ assessments." UCC's Exceptions, page 11. However, the Settlement Agreement itself recognized that the Company may not be able to fully implement changes in distribution planning processes by the Company's next rate case, and thus the Company's recognition in its initial filing that there is room for improvement is <u>not</u> contrary to the Settlement Agreement.

Consumers' replies to exceptions, p. 107 (emphasis in original). In this regard, Consumers recaps its analysis provided in this case, including its continued best efforts in accounting for EJ in distribution planning, and states that the settlement agreement in Case No. U-21224 does not require it to perform the specific analysis that UCC requests. *Id*., pp. 107-108. Consumers reiterates the process already initiated by the Commission in Case No. U-21122 with regard to the reporting of additional information by utilities and asserts that the Commission should not impose different or additional requirements that apply just to the company in this case. And lastly, as to UCC's exception over the consideration of general distribution planning issues being addressed in Case No. U-20147, Consumers states:

> Clearly the [ALJ]'s statement that some "general issues" related to distribution planning should be addressed in Case No. U-20147 did not suggest that there should be no consideration of "distribution investment concerns" in rate cases. The

> [ALJ] spent 60 pages addressing several "distribution investment concerns" in this case. See PFD, pages 30-90.
>
> The [ALJ]'s statement at page 595 was a recognition that some issues related to the Company's EDIIP are more appropriately addressed in the proceeding where the EDIIP was filed. As discussed in the PFD, these issues include more formalized standards for distribution planning and the climate horizon [sic: 50-to-100-year time horizon for climate resiliency planning] to use in distribution planning. See PFD, page 559. The Commission has recognized that Case No. U-20147 is the appropriate case to consider distribution planning issues by establishing the opportunity for interested persons to comment and present their positions on the distribution plans. See Case No. U-20147, October 24, 2023 Order. The Commission should not hold otherwise in this case.

Consumers' replies to exceptions, pp. 108-109.

The CEOs dispute Consumers' characterization of their EJ/reliability analysis and maintain that the Commission should order Consumers to conduct more granular EJ/reliability analyses, like that conducted by the CEOs in this case, to ensure that the company's rates are truly just and reasonable. CEOs' replies to exceptions, pp. 2-3 (referencing 4 Tr 3280; CEOs' initial brief, pp. 20, 22-23; CEOs' reply brief, pp. 4-6).

UCC reiterates confusion over the ALJ's recommendations here, thus making it difficult for UCC to respond to the PFD and other parties' exceptions. Nevertheless, UCC ultimately reaffirms its request for Consumers to be required to provide in the company's next rate case: (1) CEMI and CELID data, (2) census tract level data for key metrics, and (3) further analyses that compare reliability between similarly situated EJ and non-EJ communities. UCC's replies to exceptions, pp. 1-4. As part of this, UCC asks that the Commission reject Consumers' interpretation of what the ALJ recommended with regard to this data and analysis. More specifically:

> To the extent that the Company's interpretation of the [ALJ]'s recommendations is viewed as a request that the Commission overrule the unclear recommendations of the [ALJ] in its favor, the Commission should reject the Company's request. The Company's argument that any data-gathering meeting with intervenors "should be for the purpose of developing an understanding of what the Company" feels is feasible would likely not provide parties with sufficient information and would not

> resolve any issues relating to the Company's EJ analysis. The Company has previously expressed skepticism over UCC's claims that (1) its EJ analysis is unsound and (2) that there are benefits in reporting more data. UCC has already addressed both where the Company's EJ analysis falls short and why its information proposals are reasonable in testimony and in previous briefing. However, without an order from the Commission requiring the Company to conduct additional EJ analysis or provide the requested information, it is unlikely that the Company will voluntarily do so. As UCC has previously demonstrated the value of CEMI and CELID data and more granular reliability data, as well as the need for additional EJ analysis comparing reliability in likely situated communities, UCC requests that the Commission require the Company to provide this data and analysis in the Company's next rate case.
>
> The Commission should make UCC's proposals a filing requirement over the Company's objections. In addition to arguing that complying with data requests is burdensome, the Company claims that the Commission should not "establish additional rate case filing requirements that apply only to Consumers Energy." This argument ignores the recent Commission order in [Commission] Case [No.] U-21297. In that case, the Commission ordered that DTE electric "provide Customers Experiencing Multiple Interruptions data . . . moving forward and for five years prior to the rate case or distribution plan." In this case, much of the data requested by UCC is similar to what the Commission ordered DTE to provide in [Case No.] U-21297. As the Commission has previously determined that it was acceptable to require energy utilities to provide this sort of information in rate cases, UCC requests that the Commission require Consumers to provide CEMI and CELID data as a filing requirement in its next rate case.

UCC's replies to exceptions, pp. 3-4 (footnotes omitted).

The Commission finds that Consumers satisfied its commitments related to equity and outreach from Case No. U-21224. Nevertheless, the Commission makes several findings on these topics moving forward. These findings are as follows, in list form for clarity and readability considering the depth of topics addressed on the overall issue of grid equity in this case:

a. The Commission agrees with the Staff and finds that Consumers should provide EJ- and equity-related information, such as reliability metrics and investments in its future rate cases and other upcoming proceedings (with such information to be reported by community vulnerability gradations based on the MiEJScreen composite score, initially defined as 0% to less than 5%, 5% to less than 10%, and so on in 5% increments up to 95% to 100% of the MiEJScreen composite score at this time, with room for refinement in the future, including the use of other increments). 5 Tr 3742–3743; Staff's initial brief, pp. 150-152. The Commission is persuaded that this information will allow for better understanding on how reliability experiences and program investments vary for Michigan communities with different MiEJScreen scores. 5 Tr 3742; Staff's initial brief, p. 152; *see also*, MCL 24.281(3).

b. The Commission agrees with the Staff and finds that Consumers should develop, with the Staff's input, "a clear and repeatable process that allows interested parties to request, safely obtain, and use GIS data." 5 Tr 3812-3813; Staff's initial brief, pp. 168-169. The Commission is persuaded by the value this data will provide for communities and analyzing the company's plans for the future. 5 Tr 3806; Staff's initial brief, p. 168; *see also*, MCL 24.281(3).

c. As far as the ALJ's recommendation regarding a manageable list of data, the Commission finds that much of this data, CEMI and CELID data included, is already part of, and available through, the reliability data template adopted by the Commission in the March 3, 2022 order in Case Nos. U-21122 *et al*. *See*, Case No. U-21122, filings #U-21122-0067, -0069. Further, as highlighted in the December 21, 2023 order in Case No. U-21388 (December 21 order), "[a] publicly available website displaying utility-reported data filed pursuant to Case No. U-21122 will be ready by the end of the first quarter in 2024" in connection with the Commission's "work[ ] on developing new webpages surrounding data, inventorying the data that is currently requested, and considering data use guidelines—all in an effort to add additional transparency around reliability and resilience data and for that data to be more easily useable for all interested persons." December 21 order, p. 9. The Commission finds that this ongoing data collection, with improvements already in progress, offers the insight to equity and the ability for the resultant analysis that is being requested; thus, no further data requirements or processes, in this regard, are required of Consumers through this case, aside from regression analysis discussed below.

d. Consistent with the December 1 order, the Commission agrees with the CEOs and finds it appropriate for Consumers to include a regression analysis in support of reliability investments in its distribution system in future filings and to provide the data supporting its regression analyses that will allow interested persons to perform their own analyses. *See*, December 1 order, pp. 375-376.

e. Considering no objections from the company in exceptions, the Commission adopts the ALJ's findings about Consumers' acquiescence to Staff's points 3, 4, 5, and 7.

f. With regard to general distribution plan issues directed by the ALJ to Case No. U-20147 (e.g., Staff's points 2 and 6), the Commission agrees with Consumers that "the [ALJ]'s statement that some 'general issues' related to distribution planning should be addressed in Case No. U-20147 did not suggest that there should be no consideration of 'distribution investment concerns' in rate cases," with the company highlighting that the ALJ "spent 60 pages addressing several 'distribution investment concerns' in this case." Consumers' replies to exceptions, pp. 108-109 (citing PFD, pp. 30-90). Thus, issues such as formalized standards for distribution planning and the time horizon to use for climate resiliency planning in future distribution planning, along with comments on the distribution plans themselves, are appropriate for Case No. U-20147, whereas distribution investment

> concerns, where a utility relies on its distribution plan to support cost recovery requests, are appropriate for a rate case.

2. Energy Burden

Considering energy equity, the CEOs and UCC also focused on energy cost burdens and the affordability gap within the company's service territory and set forth recommendations to address these inequalities. CEOs' initial brief, pp. 8-16; UCC's initial brief, pp. 9-13.

Addressing the parties' recommendations, the ALJ stated that she:

> recognizes the effort underlying the CEO's analysis of the energy burden and affordability gap facing Michigan residents, but, as discussed above, agrees with the company that it is premature to adopt a PIPP [percent of income payment plan] program while the pilot is pending, and questions regarding the Commission's authority to fund the program as a low-income assistance program with costs borne by ratepayers have not been addressed. Consistent with the discussion above regarding calls for significant additional analysis by the company in its next rate case, this [ALJ] further declines to recommend that the Commission require the company to track and report on the affordability gap in rate cases, recommending instead that the development of appropriate affordability metrics be assigned to the Commission's affordability workgroup. And as [Consumers witness] Mr. McLean explained, the CEO's call for additional EWR can be addressed through the EWR planning process, which does include consideration of low-income programs. Similarly, community solar should be evaluated in the VGP program docket. Lastly, turning to the UCC recommendation for expanded outage credits, as discussed elsewhere in this PFD, the proper venue for addressing increased outage credits is through the rulemaking process.

PFD, pp. 565-566.

The CEOs object to the ALJ's recommendation to divert the important work of managing the affordability gap away from the company to a workgroup. The CEOs state that they set forth appropriate and non-complex affordability metrics in testimony and assert that the Commission "should work to address the staggering affordability gap by requiring utilities to report on the gap and how they will reduce the gap through their spending proposals." CEOs' exceptions, pp. 5-6. Per the CEOs, sending this to a workgroup will not only delay and frustrate the purpose of testimony provided in this case but also the work of the CEOs and other intervenors on this important issue. The CEOs state:

> Rate cases inevitably tend to increase costs and rates for customers. The Commission should have the full slate of information before it in making these critical decisions, including how utility proposals either mitigate or exacerbate energy cost burdens and affect the affordability gap. Accordingly, the Commission should order Consumers to track and mitigate energy cost burdens and the affordability gap in future rate cases.

Id., p. 6.

UCC asserts that the ALJ failed to adequately consider affordability in her PFD. More specifically:

> Despite the centrality of affordability to the ratemaking process, the [ALJ] significantly cabins [her] consideration of affordability, largely ignoring the issue across [her] recommendations. The [ALJ] improperly recommended that matters relating to affordability, such as changes to the Company's affordability assistance programs and potential additional affordability analysis, not be handled in the rate case, pushing them to other proceedings. In addition, on the issues of return on equity (ROE) and the investment recovery mechanism (IRM), the [ALJ]'s reasoning and recommendations appear to ignore affordability concerns entirely. In light of the [ALJ]'s reasoning and recommendations, UCC requests that the Commission recognize the cross-cutting nature of affordability concerns in issues such as the percent of income payment program (PIPP), ROE, and the IRM.

UCC's exceptions, pp. 12-13 (footnote omitted). From there, UCC provides further arguments on: (1) affordability being a paramount customer interest; (2) the Legislature having provided a clear signal via Public Act 231 of 2023 that affordability is central to good utility governance; (3) the energy affordability crisis being urgent, affecting hundreds of thousands of Consumers' customers; and (4) the ALJ having failed to adequately consider how affordability affects several issues (i.e., affordability tracking/reporting, the company's ROE, the company's proposed PIPP (which UCC argues the Commission should make a determination on as to whether to expedite the implementation of a PIPP program with affordability considerations in mind), and the company's proposed IRM). *Id*., pp. 13-18. UCC "urges the Commission to depart from the PFD and to instead walk side-by-side with the Legislature, which has expressed that it takes the struggles of energy insecure Michiganders seriously." *Id*., p. 16.

In response to the CEOs on affordability gap metrics, Consumers maintains that the proper venue to discuss issues related to affordability is with the EAAC and the EWR and low-income workgroups, thus supporting the ALJ's recommendation on this issue. Consumers' replies to exceptions, p. 105. The company further recaps testimony on how it considers the impacts of rates on customers, including the impact of this case if granted in full; cost saving opportunities; and customer assistance options available, including contributions made by the company for such purpose. *Id*., pp. 109-111 (citing 3 Tr 83, 95-97, 133). And lastly, as to UCC's assertion about affordability considerations when considering whether to expedite the implementation of a PIPP program, Consumers recaps testimony about the phase of pilot and for this reason argues that the ALJ correctly found that it is premature to adopt a PIPP program while the pilot is pending. Consumers' replies to exceptions, pp. 111-112 (citing 4 Tr 1553-1554; PFD, p. 565).

The Commission finds the ALJ's recommendations well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's findings and conclusions on affordability. *See*, PFD, pp. 565-566; *see also*, Part V, Section K below on the Commission's decision as to Issues Deferred to Other Proceedings.

To date, the topic of affordability has been addressed through the EAAC workgroup and its subcommittees, which the Commission finds should continue at this time. Among other advantages, the EAAC workgroup and subcommittees allow for the consideration of the many issues affecting affordability without the strict time constraints imposed by statute (MCL 460.6a(5)) and where the views and voices of all persons can be openly heard and considered on the issue, not just those that are parties in a contested case. In addition, while eager to see the results of the ongoing PIPP pilot, the Commission agrees with the ALJ that "it is premature to adopt a PIPP program while the pilot is pending." PFD, p. 566. Finally, the Commission finds that there are multiple elements that contribute to the overall affordability of utility bills, including energy assistance plans, programs, and offerings; LIA and RIA credits; VGP and EWR offerings; and affordable payment plans and finds that the EAAC workgroup is the best place to work to harmonize these various elements towards a comprehensive approach to affordability, particularly for low-income customers. The workgroup continues to work on developing appropriate affordability metrics, which are due by year end in Case No. U-20757. *See*, December 21, 2023 order in Case No. U-20757 and November 18 order, p. 485. More precisely, the Commission finds that the EAAC should develop a straw proposal on affordability metrics for the Commission to consider, share that straw proposal with interested persons for review and feedback, and then incorporate those results in the EAAC's report due by year end for consideration by the Commission.

C. State Reliability Mechanism

Consumers described its state reliability mechanism (SRM) capacity charge calculation, resulting in an SRM capacity charge of $73.87/MW-Day. 4 Tr 1327-1328, 2138-2142; Exhibit A-79; Consumers' initial brief, pp. 468-469. The Staff used the company's same calculation method but with adjustments to the company's capacity revenue requirement ($124.9 million versus $202.9 million) reached an SRM capacity charge of $45.48/MW-Day. 5 Tr 3717-3718; Exhibit S-6, Schedule F1.5; Staff's initial brief, p. 146. Energy Michigan proposed two ways for the Commission to address MISO's new resource adequacy construct and to harmonize the SRM capacity charge with COS principles. Energy Michigan's primary proposal is to set the SRM capacity charge at the MISO seasonal auction clearing price and to apply that charge to the MW value of a load service entity's seasonal capacity deficiency. 5 Tr 3522-3532. Consumers disagreed with the Staff's proposed charge. Consumers agreed that the SRM capacity charge needs to be revisited. Consumers argued, however, that this was best accomplished via the reopening of Case No. U-18239, not through an electric rate case proceeding such as the instant case. 4 Tr 2154-2156; Consumers' initial brief, pp. 469-470. The Staff argued that Energy Michigan's claims regarding the SRM should be rejected. 5 Tr 4042-4045.

The ALJ agreed with Consumers that "Case No. U-18239 is the proper docket to address changes to the MISO capacity construct, the SRM capacity charge calculation method, as well as the dispute between Staff, Energy Michigan, and anyone else who cares to weigh in, over the operation and correct interpretation of the MISO tariff." PFD, pp. 567-568.

No exceptions were filed on this issue.

The Commission agrees with Consumers and the ALJ and finds that Case No. U-18239 is the proper venue to address SRM calculation methodology issues. *See*, December 1 order, p. 307, and December 22 order, p. 385. Accordingly, the company's SRM capacity charge, based on the Commission's previous approval of the methodology for the SRM capacity charge and production-related decisions in the instant case, is as set forth below in Ordering Paragraph B.

D. Demand Response Surcharge

Consumers proposed modifying the current, three-phase regulatory framework that the Commission approved in the September 15, 2017 order in Case No. U-18369 by separating DR-related costs from the overall revenue requirement and recovering the costs through an all-encompassing DR surcharge. Per the company, "[t]his approach will streamline and simplify the reconciliation process, eliminating potentially long lags for the recognition of over-recoveries and under-recoveries in rates, and allow for timely and accurate recovery of the performance incentive." 4 Tr 2086. ABATE disputed the company's proposal as unnecessary and unreasonable. 4 Tr 2844-2845. Walmart also disputed the proposal, arguing that the appropriate forum for consideration of these non-volatile costs is in a general rate and that such costs should be recovered through base rates, not a surcharge. 5 Tr 3563-3564.

The ALJ recapped the Commission's rejections of the same proposal from Consumers in Case Nos. U-20697 and U-20963 and, although finding that the company provided more details regarding its DR surcharge proposal in the instant case, nevertheless recommended that the Commission reject the proposal at this time. The ALJ stated:

> As noted by ABATE and Walmart, Consumers has not established that the current treatment of DR costs between rate cases has resulted in unreasonably high regulatory balances or cash flow problems. And, as ABATE points out if the test year projected DR costs accurately reflect cost and benefit estimates, the surcharge is unnecessary.

PFD, pp. 572-573 (citing ABATE's initial brief, pp. 72-73); *see also*, 5 Tr 3563-3564 and Walmart's initial brief, pp. 6-11.

Consumers objects to the ALJ's recommendation. Consumers argues that the ALJ failed to recognize that the company modified its proposal in response to criticisms raised in Case Nos. U-20697 and U-20963. More specifically:

> In response to the Commission's direction, and Staff's proposal in Case No. U-20963, the Company has calculated a separate revenue requirement for the DR program inclusive of all DR related capital, O&M costs, and rate credits. See Exhibit A-26 (JCA-61). Exhibit A-188 (AMG-6) provides the development of the proposed DR surcharge to recover the test year program's revenue requirement. The DR surcharge will be adjusted during the Company's annual DR Reconciliation proceedings to account for changing costs, over/under-recoveries, and recovery of the performance incentive. 4 TR 2086. During the annual reconciliation, the Company will use the same DR surcharge methodology approved by the Commission in the most recent rate case. *Id*. With these changes, the Company's proposed surcharge conforms with the Commission's previous direction.

Consumers' exceptions, p. 154. While the ALJ contended that the proposed surcharge is unnecessary in terms of volatility and regulatory balance or cash flow concerns, Consumers states that the proposed DR surcharge nevertheless results in accurate DR rates for customers, which, as the Staff previously recognized in Case No. U-20963, are akin to PSCR costs that are both significant and out of the company's control. Consumers recaps the benefits of its proposed DR surcharge and contends that the Commission should approve its proposal. Consumers' exceptions, p. 154.

Responding, ABATE maintains that the company's proposed DR surcharge is neither necessary nor reasonable, even with the changes made from prior proceedings, and thus supports the ALJ's analysis on this issue. If, however, the Commission decides otherwise and approves the company's requested DR surcharge, ABATE asserts that the Commission "should also approve Consumers' proposed rate design, which appropriately allocates the costs to rate classes and develops a voltage differentiated demand rate for demand-billed customers." ABATE's replies to exceptions, p. 14.

The Commission adopts the ALJ's recommendation to reject Consumers' DR surcharge proposal at this time. The Commission acknowledges the company's reforms to its proposal from prior cases; however, in the company's last contested rate case (Case No. U-20963) there was a lack of agreement between the Staff and the company on the costs and credits to be included in a surcharge, and on the record in the instant case there is still no evidence that such an agreement exists. December 22 order, pp. 338-339. Given this prior discord, the Commission would like to see more input on accounting details in the future, particularly from the Staff, before a change in the way in which DR costs are recovered from ratepayers can be fully considered for approval.

E. Distribution Deferral

For authorized deferral of actual 2022 capital spending amounts above those included in rates for new business, reactive demand failures, and asset relocation programs from Case No. U-20963, Consumers proposed a 12-month surcharge to collect the $8.6 million total deferred amount from 2022 versus including the same in the revenue requirement calculated for this case. The company also addressed a similar deferral approved for actual 2023 capital spending above amounts approved for these three programs in Case No. U-21224, asking that the deferral mechanism be extended until actual 2023 amounts can be determined for inclusion in rates (since these amounts were unable to be included when the instant case was filed). More specifically, to maintain spending in reliability and forestry, Consumers requested:

i. To collect $8.6 million related to the 2022 deferral of the 2022 revenue requirement of capital spending above rate levels as approved in Case No. U-21224;

ii. To extend the deferral of the revenue requirement of 2023 capital spending above rate levels until actual 2023 capital spending is included in rates. This requested extension would begin January 1, 2024 to pick up where the deferral for 2023 capital spending approved as part of the Case No. U-21224 settlement agreement leaves off. The Company also requests that the agreed to $4 million cap included in the settlement agreement not apply to this extension; and

iii. To implement a new deferral associated with capital spending in the test year of this case, for the 12 months ending on February 28, 2025 revenue requirement of capital spending above rates levels and to continue the deferral until capital spending actuals for this period are included in rates.

4 Tr 647.

The Staff reviewed Consumers' proposal and agreed with the company's requests, with five stipulations. The Staff also proposed that the mechanism be discontinued at the end of 2026 as no longer necessary based on the company's line clearing plans and implementation of the IRM. 5 Tr 4082-4085; Staff's initial brief, pp. 180-184. MNSC opined that it is reasonable to continue the deferral of excess expenditures for these programs. 4 Tr 2653-2654. Walmart asserted that the appropriate forum to address these types of costs is in a general rate case and by way of base rates, not a surcharge. Walmart's initial brief, pp. 6-11. Consumers agreed with the Staff's stipulations except for terminating the deferral mechanism at the end of 2026. 4 Tr 487-489; Consumers' initial brief, pp. 475-476.

The ALJ agreed with Consumers and recommended that the Commission approve the company's proposed distribution deferral mechanism, with the Staff's stipulations except for terminating the mechanism in 2026. In her analysis, the ALJ found that Walmart did not specifically address the company's proposal, that MNSC supported the mechanism as reasonable, and that no party, aside from Consumers, addressed the Staff's stipulations. The ALJ reiterated her recommendation to reject the IRM in this case and, in this regard, found it "premature for the Commission to terminate the distribution mechanism, the efficacy of which should be reevaluated in the company's next rate case." PFD, p. 578.

Disagreeing with the ALJ on this issue in part, the Staff maintains that the distribution deferral mechanism should be terminated in 2026. The Staff also reiterates its support for the IRM with modifications here, which "would create the incentive necessary to maintain reliability spending[,] . . . so it supports terminating the distribution deferral mechanism at the end of 2026." Staff's exceptions, p. 9.

Consumers responds that it agrees that the Commission should approve its IRM but disagrees that such approval should result in the distribution deferral mechanism ending in 2026. The company recaps testimony in support of the need for the mechanism and supports the ALJ's conclusion that it is premature to set an end date. Consumers' replies to exceptions, pp. 75-76 (citing 4 Tr 488-489; PFD, p. 578).

The Commission agrees with the ALJ to approve the company's proposed distribution deferral mechanism, with the Staff's stipulations except for terminating the mechanism in 2026. While the Commission is not necessarily convinced on this record that a distribution deferral mechanism should exist, especially in tandem with an approved IRM, the Commission is also not convinced that terminating the distribution deferral mechanism in 2026 is appropriate, given the implementation of the new IRM for Consumers in this case (which is only approved through Year 2 at this time, ending February 28, 2026, as opposed to year end 2026) and considering the difference in programs addressed by each mechanism. The Commission thus finds that continuation of the distribution deferral mechanism should be reevaluated in the company's next rate case, similar to continuation of the company's IRM beyond Year 2, as discussed above in Part VIII, Section A of this order.

F. Accounting Authority/Regulatory Assets

As provided for in Case Nos. U-20849, U-21090, and U-21224, Consumers detailed its projected test year regulatory asset balance and amortization expenses for the decommissioning costs of Karn Units 1 and 2, along with the Campbell units, and the ash disposal costs for Karn Units 1 and 2, the previously retired Classic 7 plants, and the Campbell units. 4 Tr 640-642; Exhibits A-23, A-24, and A-25. With this, Consumers also requested that the Campbell regulatory asset decommissioning costs and ash disposal costs be amortized over a period of 10 years, both beginning in 2024. 4 Tr 642. The company additionally addressed the treatment of the remaining net book value of the Campbell units pursuant to Case No. U-21090 and indicated that the same would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset. 4 Tr 638-639; Exhibits A-21 and A-22. The company also addressed the regulatory asset treatment of the 2022 retention costs for the Campbell and Karn units pursuant to Case Nos. U-20697 and U-21090. Exhibit A-19.

The ALJ found that no party disputed the company's presentation or accounting requests and recommended that they be approved. PFD, p. 579.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation supported by the record. Accordingly, the Commission adopts the ALJ's findings and conclusion on this issue. *See*, PFD, p. 579.

G. Advanced Metering Infrastructure Business Case

Consumers provided its AMI business case update but requested that this filing requirement be removed from electric rate case filings moving forward, setting forth three main reasons:

> First, this AMI Business Case already fulfilled its purpose. As detailed previously in . . . testimony, the Company has achieved all the benefits it initially projected for its AMI investment now that all AMI meters have been installed (i.e., every customer who has not opted out of a smart meter has one). Any subsequent investments should be supported in general rate case filings and should stand on their own merits, irrespective of the original AMI investment. Second, the information contained in . . . testimony is duplicative to several other reports that the Commission requires the Company to file. As detailed earlier in . . . testimony, there are at least three annual reports that include data presented in this business case, making this requirement unnecessary. Finally, there has not been any significant change in the NPV as it continues to stay within the range calculated by Staff in Case No. U-20963.

4 Tr 1202-1203. The Staff disagreed, arguing that "the purpose of the AMI business case is to *continue* to provide justification for the AMI program, including the *continued* costs and benefits of undertaking it." 5 Tr 3985 (emphasis in original). Notably, the Staff highlighted significant investments totaling $378 million for new 5G compatible meters (i.e., replacement meters) from 2023-2032, which would significantly change the NPV if appropriately included in the calculation, along with LVD metering subprogram costs of $49.875 million in 2024-2026 due in part to AMI

meter failures. The Staff noted that the company's same request to discontinue this filing requirement was rejected by the Commission in Case Nos. U-17990, U-18322, U-20134, and U-20697 and described the value of continuing to require this information moving forward. 5 Tr 3986-3991. Consumers rebutted. 4 Tr 1205-1208.

The ALJ agreed with the Staff and found that the AMI business case requirement should continue. The ALJ reasoned:

> As Staff argues: (1) the Commission has previously determined that simply finishing the installation of AMI meters does not mean that the program is complete and that ongoing oversight is necessary to ensure AMI benefits are achieved; (2) while the company claims that the AMI business case is duplicative of other reports that Consumers is required to file, Consumers does not specifically mention any report that provides the same information as the AMI business case; and (3) although Consumers states that there has not been a significant change in the NPV since the assessment in Case No. U-20963, this is clearly not true, because the business case presented here did not include the additional almost half billion dollars in investment to replace failed meters and upgrade to 5G compatible equipment. Moreover, this [ALJ] agrees with Staff that the AMI program serves as a cautionary tale that might inform the Commission about other significant investments justified on the basis of potentially inflated future benefits.

PFD, pp. 584-585.

Consumers refers to testimony and briefing it provided in the case in response to the Staff's rationale for continuing the AMI business case but emphasizes, in exceptions, its alternative request for relief. Specifically:

> If the Commission determines the time is still not right to sunset the requirement to regularly update the Company's AMI business case, the Company asks that the Commission clarify when the time will be right and what additional conditions must be met before the Commission will release the Company from the requirement. Further direction from the Commission would at least give the Company a path forward and additional objectives to satisfy to be released from its obligation to continue filing an AMI business case *if* the Commission denies the Company's primary request for relief to be released from this obligation.

Consumers' exceptions, p. 157 (emphasis in original); *see also*, Consumers' reply brief, pp. 76-78.

Responding, the Staff states that the Commission should require Consumers to continue filing updates to its AMI business case until either "the cumulative benefits exceed the cumulative costs or until the business case period has ended," with the company's business case including all costs necessary to support benefits included within. Staff's replies to exceptions, p. 30 (citing 5 Tr 3991).

The Commission finds merit in continuing to require Consumers to file information on its AMI investment. However, the Commission clarifies that the value of this reporting is less about supporting a BCA for meters that have long-since been installed and much more about how to fully unlock the customer value of this significant investment moving forward. Specifically, the Commission is interested in the provision of information regarding continuous opportunities that the investment in AMI brings to customers and the company, including opportunities for efficiencies and cost savings; more awareness of the system and its capabilities, including how such increased awareness can contribute to improved reliability; and how to leverage the AMI infrastructure to unlock opportunities for DER deployment. Using this framework, the Commission thus finds that, in lieu of the continued provision of future advanced metering infrastructure business case updates, the company and the Staff should meet following this order to coordinate on appropriate value-focused AMI metrics and elements for the company to include in its future rate case filings—which, to be clear, is to be a substitute for the updated AMI business case filing requirement moving forward, not in addition to.

H. Home Heating Electrification Pilot

Per the settlement in Case No. U-21224, the company proposed an electrification pilot to electrify homes heated by propane, fuel oil, and kerosene—with design of the pilot in 2023, small scale implementation in 2024, and expansion through 2026 until enrollment goals have been met and evaluation requirements have been satisfied. 4 Tr 2111-2112; Exhibit A-145; Consumers' initial brief, pp. 194-195; January 19 order, Exhibit A, p. 9. The Staff recommended that the pilot, also referred to as the delivered fuel electrification pilot (DFEP), be rejected as proposed due to a lack of a BCA and other Staff-identified deficiencies including potential competitive concerns, a lack of details normally required by the Commission for pilot approval, and current evidence showing that the pilot would be a net cost to ratepayers and even more so at scale. 5 Tr 4029-4031; Staff's initial brief, pp. 184-190; Staff's reply brief, pp. 44-46. Consumers and MNSC rebutted the Staff's recommended rejection of the pilot. 4 Tr 2699-2709, 2115-2116; Consumer's initial brief, pp. 195-196; MNSC's initial brief, pp. 88-97; MNSC's reply brief, pp. 21-25.

The ALJ acknowledged the Staff's concern that the pilot is not fully developed but nevertheless agreed with the company's and MNSC's arguments, recommending approval of the DFEP "with the understanding that the utility will proactively work with Staff and interested intervenors to further develop the design and implementation details." PFD, pp. 590-591.

The Staff avers that the ALJ erred in recommending approval. The Staff reiterates that it would be inappropriate to approve the pilot given its numerous flaws and lack of specificity and states that it "is equally inappropriate to approve the pilot under the assumption that the flaws and omissions will be rectified to the point approval would be appropriate with no method of ensuring they will be." Staff's exceptions, p. 5. The Staff further notes that the Commission rejected a similarly flawed proposal in Case No. U-21297 and thus maintains that the company's DFEP proposal in the instant case should be rejected, with the company being directed to work with the Staff and interested intervenors to attempt to rectify the deficiencies to improve future proposals. Staff's exceptions, p. 5; *see also*, December 1 order, p. 256.

In response, MNSC asserts that the Commission should adopt the ALJ's recommendation to approve the pilot. MNSC states that the pilot completes the agreement from Case No. U-21224, will benefit customers by generating an estimated $18 million in net revenue, and is urgently needed to decarbonize home heating in the company's service territory. MNSC further distinguishes the pilot in this case compared to Case No. U-21297 and maintains that "not approving the pilot here and waiting until after the next rate case to even begin the pilot would be a lost opportunity for customers," in terms of cost effectiveness, environmental benefits, and federal rebate dollars and tax incentives. MNSC's replies to exceptions, pp. 72-73. Following a recap of the company's proposal, party positions, and the PFD, MNSC addresses the Staff's exceptions and asserts that the same does not warrant overturning the ALJ's recommendation. Per MNSC:

> As a general matter, many of Staff's objections focus on the potential future expansion of the DFEP to a full-scope program. But those objections are premature – the proposal before the Commission is a small pilot, and the point of the pilot is to gather the kind of information that Staff requests before developing a full program. Other Staff objections relate to certain features of the pilot and the process by which the pilot was introduced into this case. However, key features of the pilot and the process for introducing it in this case were already prescribed by the settlement. If Staff wanted a different process or features, Staff should have requested those before signing the settlement.

Id., p. 78; *see also*, *id*., pp. 78-83.

Consumers also responds and argues that the Staff's reference to Case No. U-21297 on this issue fails to provide context for the Commission's decision in that case. Consumers distinguishes its proposal in the instant case as compared to DTE Electric's in Case No. U-21297, noting that DTE Electric's proposal was on its own initiative absent agreement from any parties, contrary to Consumers' proposal in the instant case that stems from a settlement agreement "where the parties agreed to the pilot's fundamentals such as who the pilot would target and where the pilot would be proposed." Consumers' replies to exceptions, p. 96. Consumers further argues that the flaws raised by the Staff were previously stipulated to, highlighting that "[n]otably absent from the agreement of the parties are the items that Staff is now requesting." *Id*. The company reiterates the purpose of the DFEP, along with details of the pilot, maintaining that it needs to move forward with the pilot to fulfill its settlement commitments, including leveraging federal funding through the IRA, and that any delay in implementation may result in a more costly pilot. *Id*., pp. 96-97 (citing 4 Tr 2112, 2115). For these reasons, Consumers asks that the Commission approve its pilot proposal.

The Commission agrees with the Staff and finds that the company's DFEP should be rejected in its current form. The Commission notes that the settlement agreement in Case No. U-21224 called for Consumers to propose a pilot for electrifying residential use of propane, fuel oil, and other unregulated fuels and that the company would collaborate with the Staff, MNSC, and others in the design of the pilot. However, the Commission finds that the pilot as proposed is not sufficiently well developed to merit approval. Specifically, the Commission notes the lack of a BCA and that, "of the approximately 24 items that the Commission requests for pilots, nearly half are either not fully specified or are yet to be determined." PFD, p. 588 (citing 5 Tr 4029; Exhibit A-145; Staff's initial brief, p. 187). The Commission thus encourages Consumers to work with the Staff, MNSC, and other interested persons to come back in the future with an improved proposal containing more comprehensive details the Commission expects to see when presented with pilot proposals, consistent with the Commission's desire for more from DTE Electric in Case No. U-21297. *See*, February 4, 2021 order in Case No. U-20645[31] and December 1 order, p. 256.

I. Transmission Coordination

METC requested for the Commission to direct Consumers to engage in substantive discussions with METC to proactively assess the grid for EV charging impacts and to provide transparency with METC about the company's DER, DR, and DG programs to ensure resilience and reliability. METC's initial brief, pp. 19-21. More specifically, METC requested that the Commission direct Consumers to:

> (i) collaborate with METC to facilitate the provision of needed distribution system data to support system planning and operation of METC's BES [bulk electric system]; (ii) collaborate with METC to identify the specific data to be provided no later than six months from the issuance of an order in this case; and (iii) provide the agreed upon distribution system data to METC no less frequently than annually.

METC's initial brief, pp. 21-22 (citing 4 Tr 3357). Consumers rebutted METC's requests as unnecessary but did welcome METC sharing data with the company regarding METC's efforts to add transmission-connect distributed resources to its transmission system as part of collaboration between the two companies. 4 Tr 494-495.

The ALJ agreed with Consumers that an additional process for collaboration or information-sharing between the two companies is unnecessary at this time. The ALJ stated that "Consumers appears quite willing to provide relevant information to METC, if requested, and the IRP and EDIIP dockets offer additional opportunities for the parties to work together." PFD, p. 592.

No exceptions were filed on this issue.

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[31] This order was reissued by the Commission by way of an erratum on February 8, 2021, to include the attachment referenced within the order that was inadvertently omitted when first issued. *See*, Case No. U-20645, filing #U-20645-0015.

The Commission finds the ALJ’s recommendation well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ’s findings and conclusion on this issue. *See*, PFD, p. 592.

J. Customer Outreach

Pursuant to the settlement agreement approved in Case No. U-21224, Consumers stated that it scheduled and held an outreach event on May 15, 2023, in Grand Rapids, Michigan. 3 Tr 102. UCC, however, argued that Consumers did not sufficiently meet all of the goals for this event. UCC stated that “there should have been more engagement on the instant case and its impact on residential customers, particularly LMI households,” and that “[t]he event became more of a resource fair than a meaningful discussions [sic] of the issues at hand in this case.” 5 Tr 3412. In this regard, UCC recommended that Consumers should:

> put more effort into educating community members on the impacts of rate cases—particularly those residential ratepayers most vulnerable to rate increases. The Company should incorporate the feedback that it receives at these sessions into the current and future regulatory cases and other activities. Additionally, the Commission should mandate that Consumers work together with relevant stakeholders such as UCC to share the comments gathered at such events, instead of having them be shared through discovery requests.

5 Tr 3413. Consumers disagreed with UCC’s portrayal of the event and stated that it always reviews customer feedback pertaining to rate cases. 3 Tr 123-124.

The ALJ found that Consumers complied with the public outreach requirements from Case No. U-21224 but recommended that the company “be directed to continue to hold outreach events, providing customers with rate case and assistance information and an opportunity to offer feedback soon after the filing date of the company’s next rate case.” PFD, p. 594.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's findings and conclusion on this issue. *See*, PFD, p. 594.

K. Issues Deferred to Other Proceedings

The ALJ lastly noted a few additional issues raised by the parties that she opined to either be beyond the scope of a rate case or more appropriate to be addressed in another case or forum. More specifically:

> The UCC made a recommendation regarding increasing outage credits, which is appropriately addressed in a rulemaking. Several parties brought up community solar issues; however, as Consumers points out, the company has submitted a proposal for community solar in its Voluntary Green Pricing case, Case No. U-21374, which is the appropriate forum to address these concerns regarding community solar.
>
> The Attorney General recommended implementation of a Service Improvement Incentive Mechanism [SIIM], a performance-based ratemaking . . . proposal, and MNSC and the UCC made recommendations for adjusting the company's ROE based on certain performance metrics. These proposals are more appropriately included as part of the docket addressing performance incentives and disincentives in Case No. U-21400. And general issues concerning distribution planning and distribution planning priorities should be taken up in the company's EDIIP case, Case No. U-20147.
>
> Lastly, the distributed generation cap is set by statute, and while the cap was recently raised to 10% of a utility's average in-state peak load for the preceding five calendar years, the discretion to raise the cap above the 10% requirement remains with the utility.

PFD, pp. 594-595.

The Attorney General argues that the ALJ erred in not recommending approval of her proposed SIIM in this case. The Attorney General states that Consumers "has steadily increased its capital spending in the last 10 years to replace aging infrastructure, increase the reliability and resilience of the distribution grid, reduce power outages, and improve the overall level of service to customers," spending approximately $4.8 billion in capital investments from 2018 to 2022, forecasting an additional capital investment amount of $3.6 billion for 2023 to 2024, and currently spending approximately $100 million annually for O&M expense on tree trimming and line clearing costs. Attorney General's exceptions, p. 45 (citing 4 Tr 3089-3090); *see also*, Attorney General's initial brief, pp. 192-197. The Attorney General continues:

> While capital expenditures and O&M expense costs have been significant drivers of the revenue requirement and rate increases in recent rate cases, [Consumers] has not achieved commensurate results in terms of performance improvement in power outages, distribution grid reliability and resilience, and reductions in power outage restoration time and costs. Therefore, the Attorney General proposes that the Commission adopt the Service Improvement Incentive Mechanism (SIIM) developed by her expert, Mr. Coppola. It helps to provide accountability for service funded by ratepayers by providing both a financial incentive to improve performance and financial penalties for falling short of specific targets for improvement.

Attorney General's exceptions, p. 46 (footnote omitted). While the ALJ claimed that this recommendation from the Attorney General is beyond the scope of this proceeding and should be addressed in Case No. U-21400, the Attorney General responds that she did present this proposal in that docket but argues that there is nothing that prevents the Commission from also considering this proposal in the instant case. The Attorney General recaps testimony about the purpose, details, and procedures for administering her proposed SIIM and states:

> "The SIIM strikes a fair balance in holding the Company accountable for performance related to capital investments and operating costs directly related to the distribution system. It provides for both incentive awards and penalties, within reason, and challenges the Company to improve service reliability and outage restoration time, among other goals." It also put [sic] guardrails on the amount of penalties or incentives due to unusual circumstances.

Attorney General's exceptions, p. 48 (footnote omitted) (quoting 4 Tr 3098). The Attorney General continues:

> Over the past years, there has [sic] been discussions and proposals made about establishing a broader performance-based ratemaking . . . system, but nothing has

> been established to date due to complexities surrounding the implementation of [performance-based ratemaking] systems. A more narrowly focused approach for holding the Company accountable for service reliability results, such as the SIIM proposed by the Attorney General can provide clear benefits to ratepayers, while a broader [performance-based ratemaking] system is developed. It is specific to reducing power outages, which is one of the greatest benefits to customers given the amounts they pay each month for electric service. As described above, the SIIM is simple and easy to implement and it can be modified later when a new or more comprehensive [performance-based ratemaking] mechanism is adopted by the Commission.

Attorney General's exceptions, p. 48.

UCC objects to the ALJ's recommendation to move general issues concerning distribution planning to Case No. U-20147. This objection is discussed in more detail and addressed above in Part VIII, Section B.1. UCC's exceptions, p. 7. UCC also objects to the ALJ's recommendation about its $2 per hour outage credit, arguing that the Commission should depart from the PFD and accept its proposal. UCC states:

> The [ALJ] is generally unresponsive to UCC's request for an alteration to the outage credit. Without addressing either UCC's arguments for why addressing the issue in this forum is procedurally appropriate nor reaching the merits, the [ALJ] dismisses the argument as better suited in the rulemaking process. This assertion is incorrect and UCC requests that the Commission find that it has jurisdiction to alter the outage credit in this rate case and adopt UCC's proposed $2 per hour alteration.

UCC's exceptions, pp. 18-19 (footnote omitted). UCC then further elaborates on the Commission's ability to consider altering the outage credit outside the rulemaking process and why the Commission should adopt its proposal in this case. *Id*., pp. 19-21.

Responding to the Attorney General, Consumers asserts that her claims in exceptions about her proposed SIIM in this case "does not give due regard to the work being done in Case No. U-21400" with regard to performance incentives and disincentives—namely the first straw proposal for comment issued in that case on August 30, 2023; the second straw proposal for comment thereafter issued on December 21, 2023, with comments to the second straw proposal due on February 2, 2024; the next engagement session with interested persons having taken place on February 12, 2024; and the evolution and improvements with the second straw proposal "that are inconsistent with several aspects of the Attorney General's proposed SIIM in this case." Consumers' replies to exceptions, pp. 97, 99. In sum, according to Consumers:

> The [ALJ] was correct that it is premature to adopt the Attorney General's SIIM at this time. There are too many important issues that still need to be resolved before some type of incentive and disincentive mechanism is ready to be included in Consumers Energy's ratemaking. The work in Case No. U-21400 is ongoing and it has been constructive. The Commission should reject the Attorney General's request to impose such a mechanism in this case, which is based on the unvetted views of one party and did not have the benefit of the work that has already occurred in Case No. U-21400. The Commission should adopt the [ALJ]'s recommendation to defer consideration of the Attorney General's SIIM to that proceeding.

Consumers' replies to exceptions, p. 99.

The Commission finds the ALJ's recommendations here to be well-reasoned and supported by past precedent and statute. *See*, e.g., December 1 order, pp. 293 and 365 on the appropriate forums to address outage credits and performance-based ratemaking proposals and MCL 460.1173. Accordingly, the Commission adopts the ALJ's findings and conclusions on issues deferred to other proceedings, including the deferral of general distribution plan issues to Case No. U-20147 as addressed by the Commission above in Part VIII, Section B.1 of this order. *See*, PFD, pp. 594-595.

THEREFORE, IT IS ORDERED that:

A. Based on the findings in this order adopting a March 1, 2024 through February 28, 2025 test year, a jurisdictional rate base of $13,669,075,000, an authorized rate of return on common equity of 9.9%, and an authorized overall rate of return of 5.86%, Consumers Energy Company is authorized to implement rates that increase its annual electric revenues by $92,009,000, on a jurisdictional basis, over the rates approved in the January 19, 2023 order in Case No. U-21224.

B. Consumers Energy Company is authorized to implement rates consistent with the revenue deficiency approved by this order on a service-rendered basis for electric service provided on and after March 15, 2024, as reflected in Attachment A (a summary of revenue by rate class), Attachment B (tariff sheets), and Attachment C (updated capacity charge calculation) to this order. Within 30 days of March 1, 2024, the date of this order, Consumers Energy Company shall file with the Commission Staff tariff sheets substantially similar to Attachment B. After the tariff sheets have been reviewed and accepted by the Commission Staff for inclusion in the tariff book, Consumers Energy Company shall promptly file the final tariff sheets in this docket and serve all parties. Consumers Energy Company shall implement a state reliability mechanism capacity charge of $16,882.95 per megawatt-year, or $46.25 per megawatt-day, for customers taking capacity service, as shown on Attachment C to this order. Attachment B contains the associated capacity rates. When filing the tariffs consistent with those ordered, Consumers Energy Company shall also update the Contributions In Aid of Construction Allowance Schedule amounts on Tariff Sheet C-4.00, Section C1.4, to be consistent with the rates approved in this order.

C. Consumers Energy Company shall file in its next general electric rate case an alternatives analysis addressing the replacement of the Karn Unit 3 Cooling Tower internal structure, including information on the most cost-efficient solution and alternatives to full replacement as described in this order.

D. If cost recovery for work on the Hardy Dam is sought in its next general electric rate case, Consumers Energy Company shall file a full evaluation of all alternative options and pricing for the work that must be done in order to remain in compliance with Federal Energy Regulatory Commission standards, with projected total costs.

E. Consumers Energy Company shall file in its next general electric rate case an updated calculation of its demand response credits that includes the latest estimate of cost of new entry and updated values of expected per-customer load reduction for credits that are administered monthly, as described in this order. Consumers Energy Company shall include actuals rather than expected values in the update whenever possible.

F. Consumers Energy Company shall evaluate penetration levels for direct current fast charging electric vehicle chargers and conduct a load shaping study for direct current fast charging electric vehicle charges as well as Level 2 chargers and evaluate whether it is appropriate for these chargers to have separate tariffs. Consumers Energy Company shall include the results of this study in its next general electric rate case.

G. Consumers Energy Company shall file its transportation electrification plan in Case No. U-21538 no later than July 1, 2024. Consumers Energy Company shall include in its transportation electrification plan in Case No. U-21538 updates of the company's projections and actual costs of the programs related to electric vehicle adoption and resulting impacts to its transportation electrification plan. Consumers Energy Company shall serve a copy of its transportation electrification plan on the parties to Case No. U-21389. Prior to filing on July 1, 2024, Consumers Energy Company shall hold at least two public meetings with interested persons regarding the company's transportation electrification plan.

H. Consumers Energy Company shall perform a formal optimization analysis of line clearing cycles that accounts for customer costs of outages, the costs of service restoration, and the costs of line clearing, including an evaluation of shorter clearing cycles as outlined in this order. As discussed in this order, the analysis should include issues involving higher contractor costs, added vegetation data, and corresponding reliability concerns regarding the proposed nine-year clearing cycle for 4.8 kilovolt circuits. Consumers Energy Company shall file this analysis by September 3, 2024, in the docket in Case No. U-20697.

I. In its next general electric rate case, Consumers Energy Company shall provide an analysis of the feasibility of more aggressive line clearing in everything outside of the first zone as discussed in this order.

J. In the matter of the electric-only staking program, Consumers Energy Company shall provide the Commission Staff with a report at the end of the three-year staking contract period that contains, at a minimum, the information outlined in this order.

K. As set forth in this order, Consumers Energy Company shall supplement its quarterly electric damage reports to include system level details throughout the year broken down by month to include the details described in this order and shall share billing amounts when a third party causes damage, costs to ratepayers when Consumers Energy Company causes damages, and penalty amounts distributed broken down by month.

L. In its next general electric rate case, Consumers Energy Company shall present detailed information that connects performance in operational metrics to proposed incentive compensation, as individual operational metrics will be scrutinized more critically going forward.

M. In its next general electric rate case, Consumers Energy Company shall provide a list of pending tax assessment litigation cases and negotiations, an accounting of estimated compared to actual tax assessments for 10 years prior to the filing, and records of any proceeds received.

N. Consumers Energy Company shall set the Rate EIP demand response credit to 100% of cost of new entry in this case, as reflected in the rate calculated for this order and set forth in Attachment B, and shall reduce the credit to 75% of cost of new entry in the company's next general electric rate case.

O. Consumers Energy Company and the Commission Staff shall work together with the Michigan Municipal Association for Utility Issues to create a standardized report as described in this order that includes information on outages by luminaire type or other metrics deemed valuable during discussions. Consumers Energy Company shall develop the ability to report outages by luminaire type or other metrics deemed valuable during discussions with the Commission Staff within six months of the date of this order.

P. Consumers Energy Company shall participate in the demand response workgroup established by the December 1, 2023 order in Case No. U-21297.

Q. Consumers Energy Company shall work with the Commission Staff to develop clarifying language for the company's demand response tariffs and related materials that customers may choose to enroll in for demand response programs developed by aggregators of retail customers. No later than September 3, 2024, Consumers Energy Company shall file with the Commission Staff tariff sheets consistent with the results of those discussions. After the tariff sheets have been reviewed and accepted by the Commission Staff for inclusion in the tariff book, Consumers Energy Company shall promptly file the final tariff sheets in this docket and serve all parties.

R. Consumers Energy Company shall align, within six months of the date of this order, Rate GPTU's mid-peak and high-peak hours with Rate EIP's mid-peak and high-peak hours. No later than September 3, 2024, Consumers Energy Company shall file with the Commission Staff tariff sheets and supporting calculations consistent with this directive. After the tariff sheets have been reviewed and accepted by the Commission Staff for inclusion in the tariff book, Consumers Energy Company shall promptly file the final tariff sheets in this docket and serve all parties.

S. As set forth and modified in this order, Consumers Energy Company's investment recovery mechanism is partially approved and subject to reevaluation before continuing beyond the approved implementation timeframe. For Year 1 of the investment recovery mechanism, Consumers Energy Company shall share its distribution investment plans with the Commission and other interested persons, including all intervening parties in the instant case and all intervening parties in the company's most recently filed rate case, as soon as reasonably possible after the date of this order. For Year 2 of the investment recovery mechanism, Consumers Energy Company shall share the same with the Commission and other interested persons, including all intervening parties in the company's most recently filed rate case, at least four months prior to the start of the investment recovery mechanism year, in other words four months prior to March 1, 2025.

T. As set forth in this order, Consumers Energy Company shall implement the grid equity recommendations adopted by the Commission in this order, including (i) the provision of environmental justice- and equity-related information, such as reliability metrics and investments in the company's future rate cases and other upcoming, applicable proceedings; (ii) the development, with the Commission Staff's input, of a clear and repeatable process that allows interested persons to request, safely obtain, and use geographic information system data; (iii) the provision of a regression analysis and related data in support of reliability investments in the company's distribution system in future filings; (iv) for future company reports of contacts reported under Mich Admin Code, R 460.3804, the provision of information to include not only a person's health status and contact description but also information on distribution system voltage, whether contact involved a wire down, and whether contact involved overhead or underground distribution infrastructure; (v) engagement from Consumers Energy Company to work with the Commission, Commission Staff, other utilities, and other interested persons to begin identifying effective, reasonable, and prudent pathways for energy security to prevent heat-related illnesses and deaths in Michigan; (vi) a pilot proposal toward which the company will work with a third-party to provide a resource for income-qualified, medically vulnerable residential customers to help coordinate and maximize the use of utility, city, state, and federal incentives for the installation of household energy waste reduction, solar, and storage; (vii) a full summary of the environmental justice and equity considerations in its next rate case, including a detailed discussion of how proposed environmental justice changes will both impact customer rates and be implemented on such rates; and (viii) engagement of interested and affected customers and communities regarding future distribution plans so the needs, wants, and concerns of interested and affected customers and communities can be considered when designing and selecting distribution system program, projects, and sites, with subsequent rate case filings then discussing how the company addressed customer concerns in its program and project justifications, where applicable.

U. As set forth in this order, the Energy Affordability and Accessibility Collaborative shall develop a straw proposal on affordability metrics for the Commission to consider, share that straw proposal with interested persons for review and feedback, and then incorporate those results in the Energy Affordability and Accessibility Collaborative's end of year report due in Case No. U-20757.

V. As set forth in this order, Consumers Energy Company's distribution deferral mechanism for the company's new business, reactive demand failures, and asset relocation programs is approved.

W. As set forth in this order, Consumers Energy Company's accounting requests relative to costs for the company's Karn units, Campbell units, and retired Classic 7 plants are approved.

X. As set forth in this order, and in lieu of the continued provision of future advanced metering infrastructure business case updates, Consumers Energy Company and the Commission

Staff shall meet as soon as reasonably possible after the date of this order to coordinate on appropriate value-focused advanced metering infrastructure metrics and elements for the company to include in its future rate case filings.

Y. As set forth in this order, Consumers Energy Company shall continue to hold outreach events to provide customers with rate case and assistance information and an opportunity to offer feedback soon after the filing date of the company's next rate case.

Z. In its next general electric rate case, Consumers Energy Company shall provide a demonstration that the current $100 contribution in aid of construction required for streetlight installation remains the appropriate contribution in light of cost of service principles and the function of the fee.

AA. In its next general electric rate case, Consumers Energy Company shall provide workpapers and a detailed explanation of the derivation of inputs to rate design and other rate case models from the company's sales forecast.

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 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

Daniel C. Scripps, Chair

Katherine L. Peretick, Commissioner

Alessandra R. Carreon, Commissioner

By its action of March 1, 2024.

Lisa Felice

Lisa Felice, Executive Secretary

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
ORDER Summary of Present and Proposed Pro Forma Revenues by Rate Schedule
Total Revenues

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line				Revenue		Net Increase / (Decrease)	
No.	Description	Customers	Sales	Present	Proposed	Revenue	Percent
		Mthly	MWh	$000	$000	$000	%
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	1,618,090	12,185,915	$ 2,224,248	$ 2,236,151	$ 11,904	0.5
2	Smart Hours RSH	16,512	125,514	22,819	22,973	154	0.7
3	Night Time Savers RPM	13,773	105,411	18,653	18,951	298	1.6
4	Non-Transmitting Meters RSM	14,474	142,301	26,189	26,387	198	0.8
5	Total Residential Class	1,662,850	12,559,141	$ 2,291,910	$ 2,304,463	$ 12,554	0.5
	Secondary Class						
6	Energy-only GS	196,122	3,996,698	$ 633,550	$ 669,321	$ 35,771	5.6
7	Time-of-Use GSTU	918	27,489	4,193	4,474	281	6.7
8	Demand GSD	20,782	2,949,510	395,241	420,720	25,479	6.4
9	Total Secondary	217,821	6,973,697	$ 1,032,984	$ 1,094,515	$ 61,531	6.0
	Primary Class						
10	Energy-only GP	1,479	805,656	$ 95,337	$ 92,997	$ (2,340)	(2.5)
11	Demand GPD	796	4,580,914	428,713	424,205	(4,508)	(1.1)
12	Time-of-Use GPTU	1,365	4,681,858	488,788	488,183	(605)	(0.1)
13	Energy Intensive EIP	17	447,618	32,177	35,133	2,956	9.2
14	Total Primary	3,656	10,516,047	$ 1,045,014	$ 1,040,518	$ (4,497)	(0.4)
	Lighting & Unmetered Class						
15	Metered Lighting GML	404	12,195	$ 1,545	$ 1,868	$ 323	20.9
16	Universal Unmetered Lighting UUL	4,686	71,839	28,616	35,683	7,067	24.7
17	Unmetered GU	461	93,426	9,896	10,241	346	3.5
18	Total Lighting & Unmetered	5,551	177,460	$ 40,056	$ 47,792	$ 7,736	19.3
	Self-generation Class						
19	Small Self-generation GSG-1	-	-	$ -	$ -	$ -	NA
20	Large Self-generation GSG-2	15	101,694	12,214	12,515	301	2.5
21	Total Self-generation	15	101,694	$ 12,214	$ 12,515	$ 301	2.5
22	Total Full Service	1,889,894	30,328,039	$ 4,422,178	$ 4,499,802	$ 77,625	1.8
	ROA SERVICE						
	Secondary Class						
23	Energy-only GS	96	23,026	$ 1,041	$ 1,340	$ 299	28.7
24	Demand GSD	462	172,462	6,526	8,078	1,553	23.8
25	Total Secondary	558	195,488	$ 7,567	$ 9,419	$ 1,852	24.5
	Primary Class						
26	Energy-only GP	59	75,604	$ 1,347	$ 1,599	$ 252	18.7
27	Demand GPD	338	3,442,823	23,011	26,713	3,702	16.1
28	Total Primary	396	3,518,427	$ 24,358	$ 28,312	$ 3,954	16.2
29	Total ROA Service	954	3,713,915	$ 31,925	$ 37,731	$ 5,806	18.2
30	Total Jurisdictional Service	1,890,848	34,041,954	$ 4,454,102	$ 4,537,533	$ 83,430	1.9
31	Plus: Rounding			-	22	23	
32	Total Jurisdictional Revenues			$ 4,454,102	$ 4,537,555	$ 83,453	1.9
33	Less: PSCR Factor Revenues			190,772	190,772	-	
34	Less: DR Surcharge			-	-	-	
35	Less: IRM Surcharge			-	2,981	2,981	
36	Total Jurisdictional Base Revenues			$ 4,263,330	$ 4,343,802	$ 80,472	1.9
37	Total Jurisdictional Revenues			4,454,102	4,537,555	83,453	1.9
38	Plus: ERC Deferral Surcharge			-	8,556	8,556	
39	Total Jurisdictional Revenues Requested			$ 4,454,102	$ 4,546,111	$ 92,008	2.1

	(a)	(b)	(c)	(d)	(e)	(f)
			Revenue		Net Increase / (Decrease)	
Line No.	Description	Sales	Present	Proposed	Revenue	Percent
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,185,915	$ 1,309,577	$ 1,196,393	$ (113,184)	(8.6)
2	Smart Hours RSH	125,514	13,356	12,222	(1,134)	(8.5)
3	Night Time Savers RPM	105,411	10,706	9,922	(784)	(7.3)
4	Non-Transmitting Meters RSM	142,301	15,556	14,293	(1,263)	(8.1)
5	Total Residential Class	12,559,141	$ 1,349,195	$ 1,232,830	$ (116,365)	(8.6)
	Secondary Class					
6	Energy-only GS	3,996,698	$ 407,937	$ 391,672	$ (16,266)	(4.0)
7	Time-of-Use GSTU	27,489	2,744	2,667	(77)	(2.8)
8	Demand GSD	2,949,510	277,469	276,349	(1,121)	(0.4)
9	Total Secondary	6,973,697	$ 688,151	$ 670,688	$ (17,463)	(2.5)
	Primary Class					
10	Energy-only GP	805,656	$ 79,920	$ 74,923	$ (4,996)	(6.3)
11	Demand GPD	4,580,914	388,824	378,174	(10,650)	(2.7)
12	Time-of-Use GPTU	4,681,858	421,973	411,582	(10,391)	(2.5)
13	Energy Intensive EIP	447,618	29,871	32,395	2,524	8.5
14	Total Primary	10,516,047	$ 920,587	$ 897,074	$ (23,514)	(2.6)
	Lighting & Unmetered Class					
15	Metered Lighting GML	12,195	$ 720	$ 818	$ 99	13.7
16	Universal Unmetered Lighting UUL	71,839	4,111	4,775	664	16.1
17	Unmetered GU	93,426	7,772	7,742	(30)	(0.4)
18	Total Lighting & Unmetered	177,460	$ 12,603	$ 13,335	$ 733	5.8
	Self-generation Class					
19	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
20	Large Self-generation GSG-2	101,694	10,526	10,526	-	-
21	Total Self-generation	101,694	$ 10,526	$ 10,526	$ -	-
22	Total Full Service	30,328,039	$ 2,981,062	$ 2,824,454	$ (156,609)	(5.3)
	ROA SERVICE					
	Secondary Class					
23	Energy-only GS	-	$ -	$ -	$ -	NA
24	Demand GSD	-	-	-	-	NA
25	Total Secondary	-	$ -	$ -	$ -	NA
	Primary Class					
26	Energy-only GP	-	$ -	$ -	$ -	NA
27	Demand GPD	-	-	-	-	NA
28	Total Primary	-	$ -	$ -	$ -	NA
29	Total ROA Service	-	$ -	$ -	$ -	NA
30	Total Jurisdictional Service	30,328,039	$ 2,981,062	$ 2,824,454	$ (156,609)	(5.3)
31	Plus: Rounding		-	11	11	
32	Total Jurisdictional Base Revenues		$ 2,981,062	$ 2,824,465	$ (156,597)	(5.3)
33	Less: PSCR Factor Revenues		190,772	190,772	-	
34	Less: DR Surcharge		-	-	-	
35	Less: IRM Surcharge		-	-	-	
36	Total Jurisdictional Base Revenues		$ 2,790,291	$ 2,633,693	$ (156,597)	(5.6)
37	Total Jurisdictional Revenues		2,981,062	2,824,465	(156,597)	(5.3)
38	Plus: ERC Deferral Surcharge		-	-	-	
39	Total Jurisdictional Revenues Requested		$ 2,981,062	$ 2,824,465	$ (156,597)	(5.3)

	(a)	(b)	(c)	(d)	(e)	(f)
Line			Revenue		Net Increase / (Decrease)	
No.	Description	Sales	Present	Proposed	Revenue	Percent
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,185,915	$ 914,671	$ 1,039,758	$ 125,087	13.7
2	Smart Hours RSH	125,514	9,463	10,752	1,288	13.6
3	Night Time Savers RPM	105,411	7,948	9,030	1,082	13.6
4	Non-Transmitting Meters RSM	142,301	10,633	12,094	1,461	13.7
5	Total Residential Class	12,559,141	$ 942,715	$ 1,071,633	$ 128,918	13.7
	Secondary Class					
6	Energy-only GS	3,996,698	$ 225,612	$ 277,649	$ 52,037	23.1
7	Time-of-Use GSTU	27,489	1,449	1,807	358	24.7
8	Demand GSD	2,949,510	117,772	144,371	26,599	22.6
9	Total Secondary	6,973,697	$ 344,833	$ 423,827	$ 78,994	22.9
	Primary Class					
10	Energy-only GP	805,656	$ 15,417	$ 18,074	$ 2,656	17.2
11	Demand GPD	4,580,914	39,889	46,031	6,142	15.4
12	Time-of-Use GPTU	4,681,858	66,815	76,601	9,787	14.6
13	Energy Intensive EIP	447,618	2,306	2,738	431	18.7
14	Total Primary	10,516,047	$ 124,427	$ 143,444	$ 19,017	15.3
	Lighting & Unmetered Class					
15	Metered Lighting GML	12,195	$ 825	$ 1,049	$ 224	27.2
16	Universal Unmetered Lighting UUL	71,839	24,505	30,908	6,403	26.1
17	Unmetered GU	93,426	2,124	2,499	376	17.7
18	Total Lighting & Unmetered	177,460	$ 27,454	$ 34,457	$ 7,003	25.5
	Self-generation Class					
19	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
20	Large Self-generation GSG-2	101,694	1,687	1,988	301	17.9
21	Total Self-generation	101,694	$ 1,687	$ 1,988	$ 301	17.9
22	Total Full Service	30,328,039	$ 1,441,115	$ 1,675,349	$ 234,233	16.3
	ROA SERVICE					
	Secondary Class					
23	Energy-only GS	23,026	$ 1,041	$ 1,340	$ 299	28.7
24	Demand GSD	172,462	6,526	8,078	1,553	23.8
25	Total Secondary	195,488	$ 7,567	$ 9,419	$ 1,852	24.5
	Primary Class					
26	Energy-only GP	75,604	$ 1,347	$ 1,599	$ 252	18.7
27	Demand GPD	3,442,823	23,011	26,713	3,702	16.1
28	Total Primary	3,518,427	$ 24,358	$ 28,312	$ 3,954	16.2
29	Total ROA Service	3,713,915	$ 31,925	$ 37,731	$ 5,806	18.2
30	Total Jurisdictional Service	34,041,954	$ 1,473,040	$ 1,713,079	$ 240,039	16.3
31	Plus: Rounding		-	11	11	
32	Total Jurisdictional Base Revenues		$ 1,473,040	$ 1,713,090	$ 240,050	16.3
33	Less: PSCR Factor Revenues		-	-	-	
34	Less: DR Surcharge		-	-	-	
35	Less: IRM Surcharge		-	2,981	2,981	
36	Total Jurisdictional Base Revenues		$ 1,473,040	$ 1,710,109	$ 237,069	16.1
37	Total Jurisdictional Revenues		1,473,040	1,713,090	240,050	16.3
38	Plus: ERC Deferral Surcharge		-	8,556	8,556	
39	Total Jurisdictional Revenues Requested		$ 1,473,040	$ 1,721,646	$ 248,606	16.9

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(Continued From Sheet No. A-2.00)

SECTION C
COMPANY RULES AND REGULATIONS

Part I - Applicable to All Customers **Sheet No.**

(Continued on Sheet No. A-4.00)

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(Continued From Sheet No. A-3.00)

SECTION C
COMPANY RULES AND REGULATIONS (Contd)

SECTION D
RATE SCHEDULES

(Continued on Sheet No. A-5.00)

(Continued From Sheet No. B-4.00)

B2. CONSUMER STANDARDS AND BILLING PRACTICES FOR ELECTRIC AND NATURAL GAS SERVICE (R 460.101 – R 460.169) (Contd)
https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20460.101%20to%20R%20460.169.pdf

PART 10. DISPUTES, HEARINGS AND SETTLEMENTS

R 460.154 Disputed matters.
R 460.155 Customer hearing and hearing officers for residential and small nonresidential customers.
R 460.156 Notice of hearing.
R 460.157 Customer hearing procedures.
R 460.158 Settlement agreement procedures for residential and small nonresidential customers.
R 460.159 Default of settlement agreement procedures for residential and small nonresidential customers.

PART 11. APPEAL PROCEDURES
R 460.160 Customer hearing appeal.
R 460.161 Filing procedures.
R 460.162 Customer hearing appeal procedures.
R 460.163 Interim determination.
R 460.164 Appeal review.
R 460.165 Customer hearing appeal decision.
R 460.166 Failure to comply with customer hearing appeal decision.
R 460.167 Same dispute.
R 460.168 Formal appeal.
R 460.169 Other remedies.

B3. UNCOLLECTIBLES ALLOWANCE RECOVERY FUND (R 460. 2601 - R 460.2625) (RESIDENTIAL CUSTOMERS) – Rescinded November 12, 2013
https://dmbinternet.state.mi.us/DMB/ORRDocs/AdminCode/108_09_AdminCode.pdf

B4. BILLING PRACTICES APPLICABLE TO NON-RESIDENTIAL ELECTRIC AND GAS CUSTOMERS (R 460.1601 – 460.1640) – Rescinded December 11, 2017
http://www.michigan.gov/documents/mpsc/New_Billing_Practices_Applicable_to_Non-residential_Electric_and_Gas_Customers_608318_7.pdf

B5. UNDERGROUND ELECTRIC LINES (R 460.511 - R 460.519)
https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=824_10790_AdminCode.pdf

Refer to the Company's approved Rule C6.2, Underground Policy.

R 460.511 Payment of difference in costs.
In Case No. U-21389 ordered on XXXXXX XX, XXXX, the Company was granted a permanent waiver of Rule 511 for the limited purpose of waiving contribution in aid of construction charges to customers participating in the Company's PowerMIDrive or PowerMIFleet program. This is to ensure that the difference of costs associated with overhead versus underground line infrastructure installed by the Company may not be assessed to the customer.
R 460.512 Extensions of residential distribution and service lines in the lower peninsula mainland.
R 460.513 Extensions of commercial and industrial lines in lower peninsula mainland.
R 460.514 Costs in case of special conditions.
R 460.515 Extensions of lines in other areas of state.
R 460.516 Replacement of existing overhead lines.
R 460.517 Underground facilities for convenience of utilities or where required by ordinances.
R 460.518 Exceptions.
R 460.519 Effective dates.

B6. ELECTRICAL SUPPLY AND COMMUNICATION LINES AND ASSOCIATED EQUIPMENT (R 460.811 – R 460.814)
https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=1683_2017-007LR_AdminCode.pdf

Refer to the Company's approved Rate Schedules for Pole Attachment and Conduit Use Rate PA and General Service Unmetered Rate GU.

R 460.811 Definitions.
R 460.812 Purpose.
R 460.813 Standards of good practice; adoption by reference.
R 460.814 Exemption from rules; application to Commission; public hearing.

(Continued on Sheet No. B-6.00)

(Continued From Sheet No. C-3.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.4 Extraordinary Facility Requirements and Charges (Contd)

Contribution In Aid of Construction Allowance Schedule							
		With a Full Service Contract, by Contract Duration					Without Full Service Contract
Schedule	Customer Voltage Level(CVL)	1 Year	2 Year	3 Year	4 Year	5 Year	
General Service Primary Rate GP	1	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
	2	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
	3	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
Large General Service Primary Demand Rate GPD	1	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
	2	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
	3	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
General Service Primary Time-of-Use Rate GPTU	1	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	NA
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	
	2	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	NA
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	
	3	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	NA
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	
Energy Intensive Primary Rate EIP	1	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	NA
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	
	2	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	NA
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	
	3	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	NA
		TBD	*TBD*	*TBD*	*TBD*	*TBD*	

The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, minimum bills, require upfront deposit and other service conditions, including, but not limited to, when the customer's load requirements are of a short-term duration, temporary or a transient nature, or if in the opinion of the Company, the customer does not have acceptable credit history or represents an unacceptable credit risk or other reasons within the sound discretion of the Company.

Contributions in Aid of Construction otherwise required by the Company may be suspended for *charging* sites participating in the PowerMIDrive *Public or PowerMIFleet programs*.

C1.5 Invalidity of Oral Agreements or Representations

When a written contract is required, no employee or agent of the Company is authorized to modify or supplement the Rules and Regulations and Rate Schedules of the Electric Rate Book by oral agreement or representation, and no such oral agreement or representation shall be binding upon the Company.

(Continued on Sheet No. C-5.00)

(Continued From Sheet No. C-14.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

D. Rate Application for Seasonal Condominium Campgrounds (Contd)

(6) The customer must notify individuals and co-owners utilizing the customer's property that requests and concerns regarding electric service will be addressed between the single legal entity and ownership and primary operating authority, not with individuals.

(7) The customer shall be responsible for ensuring that the electrical facilities are adequate to meet the needs of the units placed within the Seasonal Condominium Campground in their entirety and shall pay the Company for any charges incurred for modifications necessary to accommodate load according to other portions of this Electric Rate Book.

C4.4 Resale

This provision is closed to resale for general unmetered service, unmetered or metered lighting service and new or expanded service for resale for residential use.

No customer shall resell electric service to others except when the customer is served under a Company rate expressly made available for resale purposes, and then only as permitted under such rate and under this rule.

Where, in the Company's opinion, the temporary or transient nature of the proposed ultimate use, physical limitation upon extensions, or other circumstances, make it impractical for the Company to extend or render service directly to the ultimate user, the Company may allow a customer to resell electric service to others.

A resale customer is required to take service under the resale provision of one of the following rates for which they qualify: General Service Secondary Rate GS, General Service Secondary Time-of-Use Rate GSTU, General Service Secondary Demand Rate GSD, General Service Primary Rate GP, Large General Service Primary Demand Rate GPD, or General Service Primary Time-of-Use Rate GPTU. Resale Service is provided pursuant to a service contract providing for such resale privilege. Service to each ultimate user shall be separately metered.

A. If the resale customer elects to take service under a Company Full Service resale rate, the ultimate user shall be served and charged for such service under standard Rate RSM for residential use or under the appropriate standard General Service Rate applicable in the Company's Electric Rate Book available for similar service under like conditions. Reselling customers are not required to offer or administer any additional service provisions or nonstandard rates contained in the Electric Rate Book, such as the Income Assistance Service Provision or the Educational Institution Service Provision.

B. If the resale customer elects to take service under a Company Retail Open Access Service rate, the ultimate user shall be served and charged for such service under Rate ROA-R for residential use or under Rate ROA-S or ROA-P applicable in the Company's Electric Rate Book available for similar service under like conditions.

C. If the ultimate user is a campground lot or boat harbor slip, the resale customer has the option to charge a maximum of the following all inclusive rate per kWh in place of billing the ultimate customer on the appropriate standard Company tariff rate:

$0.178872	per kWh for all kWh during the months of June-September
$0.165117	per kWh for all kWh during the months of October-May

The Company shall be under no obligation to furnish or maintain meters or other facilities for the resale of service by the reselling customer to the ultimate user.

The service contract shall provide that the reselling customer's billings to the ultimate user shall be audited each year by February's month end, for the previous calendar year. The audit shall be conducted either by the Company, if the Company elects to conduct such audit, or by an independent auditing firm approved by the Company. The reselling customer shall be assessed a reasonable fee for an audit conducted by the Company. If the audit is conducted by an independent auditing firm, the customer shall submit a copy of the results of such audit to the Company in a form approved by the Company.

(Continued on Sheet No. C-16.00)

(Continued From Sheet No. C-25.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.6 Customer-Selected Due Date Program

Notwithstanding other provisions in this tariff book, the Company, at its discretion, may provide its electric service customers and combination electric and gas service customers the option to select the day of the month on which their bill is due, regardless of the meter read date. Participating customers must have an electric AMI transmitting technology meter.

Participation in the Customer-Selected Due Date Program is available to customers, as determined by the Company, when technically feasible based on the customer's selected rate and billing options. Customers not eligible to participate include, but not limited to, customers billed on a calendar-month basis, customers participating in Retail Open Access and customers participating in the Net Metering Program.

The Customer-Selected Due Date Program is only available for the following rate categories: Residential Summer On-Peak Basic (RSP), Residential Smart Hours (RSH), Residential Nighttime Savers (RPM), General Service Secondary (GS), General Service Secondary Demand (GSD), General Service Primary (GP) and General Service Metered Lighting (GML).

(This sheet has been cancelled and is reserved for future use)

(Continued From Sheet No. C-26.10)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS

C6.1 Overhead Extension Policy

Applications for electric service which require the construction of an overhead distribution system shall be granted under the following conditions:

A. Residential Customers

The Company shall construct single-phase distribution line extensions at its own cost a distance of 600 feet, for each residential dwelling.

The length of the distribution line extension shall be measured from the nearest point of connection to the Company's facilities from which the extension can be made to the point from which the service line to the customer shall be run.

Distribution line extensions in excess of the above 600 feet shall require a deposit for the estimated cost of such excess footage. The required deposit for such excess footage shall be $3.50 per lineal foot less 25%.

The Company shall make a one-time refund, five years from the completion date of the extension or upon completion of the customer's construction, whichever the customer chooses, of $1,000 for each additional residential customer and/or three times the estimated annual revenue for each additional General Service customer who connects directly to the line for which a deposit was required. Refund allowances shall first be credited against the 25% reduction before a refund is made to the customer based on the customer's cash deposit. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy. Total refund shall not exceed the amount of the original deposit.

(Continued on Sheet No. C-27.00)

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C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.1 Overhead Extension Policy (Contd)

C. General (Contd)

(6) The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, amount of deposit and refunds thereon, minimum bills or other service conditions with respect to the customers or prospective customers whose load requirements exceed the capacity of the available distribution system in the area, or whose load characteristics or special service needs require unusual investments by the Company in Service Facilities or where there is not sufficient assurance of the permanence of the use of the service. The Company shall construct overhead electric distribution facilities and extensions only in the event it is able to obtain or use the necessary materials, equipment and supplies. The Company, subject only to review by the Commission, reserves the right, in its discretion, to allocate the use of such materials, equipment and supplies it may have on hand from time to time among the various classes of customers and prospective customers and among various customers and prospective customers of the same class.

(7) Contributions in Aid of Construction otherwise required by the Company may be suspended for *charging* sites participating in the PowerMIDrive *Public or PowerMIFleet programs*.

(8) All service rendered shall be subject to the Company's Standard Contract forms and to its Electric Rate Book.

(9) Any charges, deposits or contributions may be required In Advance of commencement of construction.

C6.2 Underground Policy

A. General

This rule sets forth the conditions under which the Company shall install direct burial underground electric distribution systems and underground service connections for residential and General Service customers. For the purpose of this rule, such underground distribution facilities are defined as those facilities operated at 15,000 Volts or less phase to ground wye connected or 20,000 Volts or less phase to phase delta connected.

The general policy of the Company is that real estate developers, property owners or other applicants for underground service shall make a contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between underground and equivalent overhead facilities.
Methods for determining this cost differential for specific classifications of service are provided herein. In cases, where the nature of service or the construction conditions are such that these conditions are not applicable, the general policy stated above shall apply.

In cases where the Company does not require underground electric distribution systems and/or underground service connections, but is required to underground such facilities by state or local law or regulation, the Company may adjust the contribution in aid of construction to account for such requirement.

It shall be mandatory that all original electric distribution systems installed in new residential subdivisions and in existing residential subdivisions in which overhead electric distribution facilities have not already been constructed be placed underground, except that a lot within a subdivision facing a previously existing street or county road and having an existing overhead distribution line on its side of the street or county road shall be served with an underground service from these facilities and shall be considered a part of the underground service area. It shall also be mandatory that all original service connections installed to serve one-family or two-family dwellings from an underground distribution system be placed underground.

Except as otherwise provided in the following paragraph, it shall be mandatory that all new General Service distribution systems and service connections installed in the vicinity of or on the customer's premises to be served, and constructed solely to serve the customer or a group of adjacent customers, be placed underground.

(Continued on Sheet No. C-29.00)

(Continued From Sheet No. C-33.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.2 Underground Policy (Contd)

E. Where, in the Company's judgment, practical difficulties exist, such as frost or water conditions, rock near the surface, or where there are requirements for deviation from the Company's filed construction standards, the per foot charges included in this Rule C6.2, Underground Policy, shall not apply and the contribution in aid of construction shall be equal to the estimated difference in cost between overhead and underground facilities but not less than the contribution calculated under the appropriate per foot charge.

F. Where electric facilities are placed underground at the option of the Company for its own convenience, or where underground construction is required by ordinance in heavily congested downtown areas, the Company shall bear the cost of such construction.

G. Conditions

The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, amount of deposit and refunds thereon, minimum bills or other service conditions with respect to the customers or prospective customers whose load requirements exceed the capacity of the available distribution system in the area, or whose load characteristics or special service needs require unusual investments by the Company in Service Facilities or where there is not sufficient assurance of the permanence of the use of the service. The Company shall construct underground electric distribution facilities and extensions only in the event it is able to obtain or use the necessary materials, equipment and supplies. The Company, subject only to review by the Commission, reserves the right, in its discretion, to allocate the use of such materials, equipment and supplies it may have on hand from time to time among the various classes of customers and prospective customers and among various customers and prospective customers of the same class.

Contributions in Aid of Construction otherwise required by the Company may be suspended for *charging* sites participating in the PowerMIDrive *Public or PowerMIFleet programs*.

All service rendered shall be subject to the Company's Standard Contract forms and to its Electric Rate Book.

H. Any charges, deposits or contributions may be required In Advance of commencement of construction.

(Continued on Sheet No. C-35.00)

(Continued From Sheet No. C-35.00)

C8. POWER SUPPLY COST RECOVERY (PSCR) CLAUSE (Contd)

A. Applicability of Clause (Contd)

"Power Supply Costs" means those elements of the costs of fuel and purchased and net interchanged power as determined by the Commission to be included in the calculation of the Power Supply Cost Recovery Factor. The Commission determined in its Order in Case No. U-10335 dated May 10, 1994 that the fossil plant emissions permit fees over or under the amount included in base rates charged the Company are an element of fuel costs for the purpose of the clause.

B. Billing

(1) The Power Supply Cost Recovery Factor shall consist of an adjustment factor of *1.07573* applied to projected average booked cost of fuel burned for electric generation and purchased and net interchange power incurred above or below a cost base of $0.05570 per kWh (excluding line losses). Average booked costs of fuel burned and purchased and net interchange power shall be equal to the booked costs in that period divided by that period's net system kWh requirements. The average booked costs so determined shall be truncated to the full $0.00001 cost per Kilowatt-hour. Net system kWh requirements shall be the sum of the net kWh generation and net kWh purchased and interchange power.

(2) Each month the Company shall include in its rates a Power Supply Cost Recovery Factor up to the maximum authorized by the Commission as shown on Sheet No. D-6.00.

Should the Company apply lesser factors than those shown on Sheet No. D-6.00, or if the factors are later revised pursuant to Commission Orders or Michigan Compiled Laws, Annotated, 460.6 et seq., the Company shall notify the Commission if necessary and file a revised Sheet No. D-6.00.

C. General Conditions

(1) The power supply and cost review shall be conducted not less than once a year for the purpose of evaluating the Power Supply Cost Recovery Plan filed by the Company and to authorize appropriate Power Supply Cost Recovery Factors. Contemporaneously with its Power Supply Cost Recovery Plan, the Company shall file a 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply and projections of Power Supply Costs.

(2) Not more than 45 days following the last day of each billing month in which a Power Supply Cost Recovery Factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the Power Supply Cost Recovery Factor and the allowance for cost of power included in the base rates established in the latest Commission order for the Company, and the cost of power supply.

(3) All revenues collected pursuant to the Power Supply Cost Recovery Factors and the allowance for power included in the base rates are subject to annual reconciliation proceedings.

(Continued on Sheet No. C-37.00)

(Continued from Sheet No. C-64.20)

C11. SELF-GENERATION, NET METERING AND DISTRIBUTED GENERATION (Contd)

C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)

E. Customer Billing – Category 1, 2 and 3 Customers (Cont)

a. Full Service Customers Outflow Credit
Customers will be credited per kWh or per kW of Outflow based on the power supply rates (which include transmission costs) of their Full Service Rate Schedule as shown below, plus the PSCR factor as shown on Tariff Sheet No. D-6.00.

			Residential Rates
Summer		*($0.141183)*	per kWh of On-Peak Outflow between June 1 and September 30
On-Peak Basic		*($0.092207)*	per kWh of Off-Peak Outflow between June 1 and September 30
Rate RSP		*($0.087554)*	per kWh of all Outflow kWh between October 1 and May 31
		($0.141183)	per kWh of On-Peak Outflow between June 1 and September 30
Smart Hours		*($0.092207)*	per kWh of Off-Peak Outflow between June 1 and September 30
Rate RSH		*($0.096587)*	per kWh of On-Peak Outflow between October 1 and May 31
		($0.085505)	per kWh of Off-Peak Outflow between October 1 and May 31
		($0.141183)	per kWh of On-Peak Outflow between June 1 and September 30
Nighttime Savers		*($0.103106)*	per kWh of Off-Peak Outflow between June 1 and September 30
Rate RPM		*($0.076876)*	per kWh of Super Off-Peak Outflow between June 1 and September 30
		($0.096587)	per kWh of On-Peak Outflow between October 1 and May 31
		($0.095973)	per kWh of Off-Peak Outflow between October 1 and May 31
		($0.073627)	per kWh of Super Off-Peak Outflow between October 1 and May 31
			Secondary Rates
Rate GS		*($0.100813)*	per kWh of Outflow during the billing months of June through September
		($0.087058)	per kWh of Outflow during the billing months of October through May
Rate GSTU(1)		*($0.139692)*	per kWh of On-Peak Outflow during the billing months of June through September
		($0.104353)	per kWh of Mid-Peak Outflow during the billing months of June through September
		($0.077283)	per kWh of Off-Peak Outflow during the billing months of June through September
		($0.095801)	per kWh of On-Peak Outflow during the billing months of October through May
		($0.075354)	per kWh of Off-Peak Outflow during the billing months of October through May
Rate GSD(1)		*($0.032155)*	per kWh of Outflow during the billing months of June through September
		($0.029962)	per kWh of Outflow during the billing months of October through May
		($27.58)	per kW of Outflow Demand during the billing months of June through September
		($16.55)	per kW of Outflow Demand during the billing months of October through May
(1) Outflow credit will be reduced by the applicable Interruptible Credit for GSTU and GSD customers participating on GSI Provision.			

(Continued on Sheet No. C-64.40)

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Sheet No. C-64.40

(Continued from Sheet No. C-64.30)

C11. SELF-GENERATION, NET METERING AND DISTRIBUTED GENERATION (Contd)

C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)

E. Customer Billing – Category 1, 2 and 3 Customers (Contd)

a. Full Service Customers Outflow Credit (Contd)

Primary Rates			
Rate GP			
Customer Voltage Level 1		*($0.092378)*	per kWh of outflow during the billing months of June through September
		($0.079924)	per kWh of outflow during the billing months of October through May
Customer Voltage Level 2		*($0.093527)*	per kWh of outflow during the billing months of June through September
		($0.080905)	per kWh of outflow during the billing months of October through May
Customer Voltage Level 3		*($0.094686)*	per kWh of outflow during the billing months of June through September
		($0.081888)	per kWh of outflow during the billing months of October through May
Rate GPD(2)			
Customer Voltage Level 1		*($0.044464)*	per kWh of On-Peak Outflow during the billing months of June through September
		($0.028405)	per kWh of Off-Peak Outflow during the billing months of June through September
		($25.83)	per kW of Outflow Demand during the billing months of June through September
		($0.033984)	per kWh of On-Peak Outflow during the billing months of October through May
		($0.029617)	per kWh of Off-Peak Outflow during the billing months of October through May
		($22.96)	per kW of Outflow Demand during the billing months of October through May
Customer Voltage Level 2		*($0.044980)*	per kWh of On-Peak Outflow during the billing months of June through September
		($0.028734)	per kWh of Off-Peak Outflow during the billing months of June through September
		($26.15)	per kW of Outflow Demand during the billing months of June through September
		($0.034378)	per kWh of On-Peak Outflow during the billing months of October through May
		($0.029960)	per kWh of Off-Peak Outflow during the billing months of October through May
		($23.25)	per kW of Outflow Demand during the billing months of October through May
Customer Voltage Level 3		*($0.045478)*	per kWh of On-Peak Outflow during the billing months of June through September
		($0.029052)	per kWh of Off-Peak Outflow during the billing months of June through September
		($26.49)	per kW of Outflow Demand during the billing months of June through September
		($0.034759)	per kWh of On-Peak Outflow during the billing months of October through May
		($0.030292)	per kWh of Off-Peak Outflow during the billing months of October through May
		($23.55)	per kW of Outflow Demand during the billing months of October through May
(2) For customers on Rate GPD GI Provision, On-Peak kW Outflow Credit shall be reduced by $7.00 per kW during the billing months of June through September and $6.00 per kW during the billing months of October through May.			

(Continued on Sheet No. C-64.50)

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Consumers Energy Company

Sheet No. C-64.50

(Continued from Sheet No. C-64.40)

C11. SELF-GENERATION, NET METERING AND DISTRIBUTED GENERATION (Contd)

C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)

E. Customer Billing – Category 1, 2 and 3 Customers (Contd)

a. Full Service Customers Outflow Credit (Contd)

Rate GPTU			
Customer Voltage Level 1		*($0.127765)*	per kWh of High-Peak Outflow between June 1 and September 30
		($0.111968)	per kWh of Mid-Peak Outflow between June 1 and September 30
		($0.085182)	per kWh of Low-Peak Outflow between June 1 and September 30
		($0.068781)	per kWh of Off-Peak Outflow between June 1 and September 30
		($0.089340)	per kWh of High-Peak Outflow between October 1 and May 31
		($0.084366)	per kWh of Mid-Peak Outflow between October 1 and May 31
		($0.075284)	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 2		*($0.129338)*	per kWh of High-Peak Outflow between June 1 and September 30
		($0.113354)	per kWh of Mid-Peak Outflow between June 1 and September 30
		($0.086239)	per kWh of Low-Peak Outflow between June 1 and September 30
		($0.069625)	per kWh of Off-Peak Outflow between June 1 and September 30
		($0.090435)	per kWh of High-Peak Outflow between October 1 and May 31
		($0.085403)	per kWh of Mid-Peak Outflow between October 1 and May 31
		($0.076207)	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 3		*($0.130916)*	per kWh of High-Peak Outflow between June 1 and September 30
		($0.114748)	per kWh of Mid-Peak Outflow between June 1 and September 30
		($0.087306)	per kWh of Low-Peak Outflow between June 1 and September 30
		($0.070472)	per kWh of Off-Peak Outflow between June 1 and September 30
		($0.091530)	per kWh of High-Peak Outflow between October 1 and May 31
		($0.086443)	per kWh of Mid-Peak Outflow between October 1 and May 31
		($0.077132)	per kWh of Off-Peak Outflow between October 1 and May 31
Rate EIP			
Customer Voltage Level 1		*($0.195586)*	per kWh of Critical Peak Outflow between June 1 and September 30
		($0.130391)	per kWh of High-Peak Outflow between June 1 and September 30
		($0.115405)	per kWh of Mid-Peak Outflow between June 1 and September 30
		($0.089809)	per kWh of Low-Peak Outflow between June 1 and September 30
		($0.067791)	per kWh of Off-Peak Outflow between June 1 and September 30
		($0.135787)	per kWh of Critical Peak Outflow between October 1 and May 31
		($0.090524)	per kWh of High-Peak Outflow between October 1 and May 31
		($0.086691)	per kWh of Mid-Peak Outflow between October 1 and May 31
		($0.075057)	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 2		*($0.197979)*	per kWh of Critical Peak Outflow between June 1 and September 30
		($0.131986)	per kWh of High-Peak Outflow between June 1 and September 30
		($0.116824)	per kWh of Mid-Peak Outflow between June 1 and September 30
		($0.090917)	per kWh of Low-Peak Outflow between June 1 and September 30
		($0.068620)	per kWh of Off-Peak Outflow between June 1 and September 30
		($0.137442)	per kWh of Critical Peak Outflow between October 1 and May 31
		($0.091628)	per kWh of High-Peak Outflow between October 1 and May 31
		($0.087750)	per kWh of Mid-Peak Outflow between October 1 and May 31
		($0.075974)	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 3		*($0.200370)*	per kWh of Critical Peak Outflow between June 1 and September 30
		($0.133580)	per kWh of High-Peak Outflow between June 1 and September 30
		($0.118248)	per kWh of Mid-Peak Outflow between June 1 and September 30
		($0.092031)	per kWh of Low-Peak Outflow between June 1 and September 30
		($0.069448)	per kWh of Off-Peak Outflow between June 1 and September 30
		($0.139093)	per kWh of Critical Peak Outflow between October 1 and May 31
		($0.092728)	per kWh of High-Peak Outflow between October 1 and May 31
		($0.088806)	per kWh of Mid-Peak Outflow between October 1 and May 31
		($0.076889)	per kWh of Off-Peak Outflow between October 1 and May 31

b. Retail Open Access Customers
The Outflow Credit will be determined by the Retail Service Supplier

(Continued on Sheet No. C-64.60)

(Continued From Sheet No. C-76.00)

C18. STANDARD OFFER - PURCHASED POWER (Contd)

D. Monthly Rate (Contd)

Rate Options (Contd)

Capacity

The monthly capacity payment will be equal to the number of Zonal Resource Credits ("ZRCs") that MISO determines the seller's QF can supply to the Company for the applicable MISO resource planning period multiplied by the applicable capacity rate expressed in such units of capacity. The current resource planning period is the planning year which runs from June 1st of each year through May 31st of the following year. If no historical generation data is available for the first year of generation a QF shall be assigned the MISO class average capacity credits by technology.

Capacity value paid to QFs does not depend on whether the Company actually obtains ZRCs for such capacity, only that the Company could obtain ZRCs for the QF capacity. Capacity value paid to a QF is in units of $ per ZRC-Month. MISO ZRCs are equal to the project's nameplate capacity (in MW_{AC}) modified by the MISO effective load carrying capacity (ELCC) calculation.

Capacity will be paid based on the average of the methodologies utilized by MISO at the time the QF contract is executed and at the time of capacity delivery from the QF, according to the MISO Business Practices Manual (BPM) calculation method effective at the respective times.

Eligible QFs that meet the requirements of Section C18A (1) or C18A (2) of this Rule can select one of the Energy Rate Options listed below:

Rate Option	**Energy Rate $/kWh**			
1. As Available Rate	Actual MISO Day Ahead Locational Marginal Price (LMP) at the Company's CONS.CETR load node under a 15-year term then multiplied by 1 plus the line loss adjustment factor of *2.40*% for interconnection voltages less than 46 kV or *1.31*% for interconnection voltage at 46 kV and less the Administrative Fee of $0.001/kWh.			
2. LMP Energy Rate Forecast (Year 1-5)	A 10-year term based on a forecast of LMPs for the first five years and year six through year 10 of the term will be based on actual LMPs as described below. Rates include the line loss adjustment and Administrative Fee.			
	On-Peak Energy Rate Interconnection Voltage <46 kV	**Off-Peak Energy Rate Interconnection Voltage <46 kV**	**On-Peak Energy Rate Interconnection Voltage =46 kV**	**Off-Peak Energy Rate Interconnection Voltage =46 kV**
Year	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
2022	$0.02983	$0.02477	$0.02955	$0.02453
2023	$0.03076	$0.02553	$0.03048	$0.02529
2024	$0.03118	$0.02643	$0.03089	$0.02618
2025	$0.03145	$0.02646	$0.03116	$0.02621
2026	$0.03293	$0.02755	$0.03263	$0.02729
2027	$0.03455	$0.02863	$0.03423	$0.02836
2028	$0.03527	$0.02874	$0.03495	$0.02847
2029	$0.03621	$0.02973	$0.03588	$0.02945
2030	$0.03724	$0.03049	$0.03690	$0.03021
Actual LMP (Year 6-10)	Actual MISO Day Ahead Locational Marginal Price (LMP) at the Company's CONS.CETR load node under the remaining contract term then multiplied by 1 the line loss adjustment factor of *2.40*% for interconnection voltages less than 46 kV or *1.31*% for interconnection voltage at 46 kV and less the Administrative Fee of $0.001/kWh.			

(Continued on Sheet No. C-78.00)

(Continued From Sheet No. C-78.00)

C19. TRANSPORTATION ELECTRIFICATION PROGRAMS (TEPS)

The Company's Transportation Electrification Programs (TEPs) have been created to support the development of infrastructure within the Company's service territory needed to accommodate widespread adoption of electric vehicles (EVs) and help optimize use of the grid. TEPs will also increase battery and plug-in hybrid electric vehicle (EV) charging capabilities and charging infrastructure across the state, while improving off-peak utilization of the electric grid to benefit all electric customers. Eligible customers who participate in these programs may receive a rebate incentive for optimizing use of their electric vehicle supply equipment (EVSE) to help reduce the cost of make-ready infrastructure and EVSE but the EVSE must be separately metered from all other electrical load and used for the exclusive purpose of charging electric vehicle batteries.

Customers not participating in TEPs that still want to install EVSE at their premises may select a Rate Schedule commensurate with their Non-Residential or Residential usage as applicable but may incur additional costs due to co-incident peak usage of their EVSE, exceeding design standards, or both.

C19.1 Residential Electric Vehicle Programs

A. Definitions

(1) "AMI Monitoring" means advanced metering infrastructure monitoring which stores, tracks, and communicates usage data with the Company.

(2) "Electric Vehicle" means a motorized vehicle that has a battery instead of a gasoline tank, and an electric motor instead of an internal combustion engine. For purposes of the Residential Electric Vehicle Program, the term shall also include Plug-in hybrid electric vehicles (PHEVs), which are a combination of gasoline and electric vehicles. In addition to a plug-in battery, such vehicles have an electric motor, a gasoline tank and an internal combustion engine.

(3) "Electric Vehicle Charging Outlet" means a NEMA 14-50 outlet, or other similar technology subject to the sole discretion and approval of the Company.

B. On-Bill Installment Payment Plan and Rebate Qualifications for Electric Vehicle Charging Outlet Installation

(1) Eligibility

Residential Customers taking service on Residential Smart Hours Rate RSH or Residential Nighttime Savers Rate RPM may be eligible for the On-Bill Installment Payment Plan to pay for the cost of installation of an Electric Vehicle Charging Outlet and may also be eligible for a one-time initial rebate of up to $500 to offset installation charges. Residential Customers taking service on Residential Smart Hours Rate RSH or Residential Nighttime Savers Rate RPM who meet the eligibility criteria of the Income Assistance Service Provision or the Low Income Assistance Credit may qualify for a one-time initial rebate of up to $1000 to offset installation charges in lieu of the standard initial rebate of $500.

Multifamily Dwellings containing four or fewer households served through a single meter taking service on Residential Smart Hours Rate RSH or Residential Nighttime Savers Rate RPM may be eligible for the On-Bill Installment Payment Plan to pay for the cost of installation of an Electric Vehicle Charging Outlet and may be eligible for a one-time initial rebate of up to $500 to offset installation charges. If the existing single meter of the Multifamily Dwelling cannot serve the parking area of the dwelling, the premises may be eligible for an enhanced rebate of up to $7500 for installation of at least two Electric Vehicle Charging Outlets or hard-wired chargers rated at 50 amps.

Residential Customers interested in the On-Bill Installment Payment Plan shall submit an online application to determine eligibility. Eligible customers shall select an installer from a list of Company pre-approved installers, using the Company's website, to install the Electric Vehicle Charging Outlet at the eligible address. The Electric Vehicle Charging Outlet shall be installed at the address displayed on the registration of the Electric Vehicle, which must be the Principal Residence of the customer. In the event the customer fails to utilize a pre-approved installer set forth on Company's website, eligibility to participate in the On-Bill Installment Payment Plan may be revoked, which may result in the customer paying the installer directly and forfeiting the benefits associated with the On-Bill Installment Payment Plan.

At the Company's sole discretion, eligible Residential Customers may enroll in the On-Bill Installment Payment Plan prior to receipt of a valid State-issued Electric Vehicle registration if the customer has proof of an existing reservation for an Electric Vehicle. In the event that a customer is enrolled in the On-Bill Installment Payment Plan under the program and an Electric Vehicle Charging Outlet is installed pursuant to said approval, but the customer fails to ultimately obtain an Electric Vehicle or otherwise provide proof of a valid State-issued Electric Vehicle registration, the customer's eligibility to participate in the On-Bill Installment Payment Plan may be revoked, and the customer may be required to pay the full cost of the Electric Vehicle Charging Outlet and its installation without the benefit provided for under the On-Bill Installment Payment Plan.

(Continued on Sheet No. C-80.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Sheet No. C-80.00**

(Continued From Sheet No. C-79.00)

C19. TRANSPORTATION ELECTRIFICATION PROGRAMS (TEPS) (Contd)

C19.1 Residential Electric Vehicle Programs (Contd)

B. On-Bill Installment Payment Plan and Rebate Qualifications for Electric Vehicle Charging Outlet Installation (Contd)

(2) On-Bill Installment Payment Plan

The On-Bill Installment Payment Plan Monthly Amount is calculated as the total of installation fee of the selected pre-approved installer plus a $10 one-time administrative fee less an eligible rebate divided by 12. The On-Bill Installment Payment Plan will be billed on the customer invoices within 45 days following completion of the installation.

The On-Bill Installment Payment will appear as a separate line item on the customer invoice for 12 billing months Customers may pay the entirety of the On-Bill Installment Plan in less than 12 months without penalty.

A participating customer shall agree to the On-Bill Installment Payment Plan Monthly Amount and repayment terms.

If a Customer enrolls in the On-Bill Installment Payment Plan prior to receipt of the Electric Vehicle, the Customer shall notify the Company upon arrival of the Electric Vehicle. Upon notification, the Customer will be enrolled in AMI Monitoring.

Participation in the On-Bill Installment Payment Plan is at the sole discretion of the Company. A customer who received a shutoff notice within the nine months preceding the Customer's request to be enrolled in the Residential Electric Vehicle Program is not eligible.

If during the duration of the approved On-Bill Installment Payment Plan, the customer, for any reason, no longer owns an Electric Vehicle, the customer shall remain responsible for the full payment due under the On-Bill Installment Payment Plan until the cost of the Electric Vehicle Charging Outlet and installation are paid in full.

If the customer sells the premises where the Electric Vehicle Charging Outlet was installed, and that customer also participates in the On-Bill Installment Payment Plan, the Customer shall notify the Company of the sale, and the full amount due and owing for the Electric Vehicle Charging Station and installation shall be accelerated and the full amount due and owing included on the Customer's final bill.

(3) AMI Monitoring for On-Bill Installment Payment Plan and Rebate Participants

All Customers participating in the On-Bill Installment Payment Plan, rebate, or both shall be enrolled in AMI Monitoring and may earn one AMI Monitoring Credit per billing month to encourage Electric Vehicle charging during Off-Peak Hours. The AMI Monitoring Credit for standard Residential and Multifamily Dwelling customers is $10 per billing month. The AMI Monitoring Credit for enhanced Multifamily Dwelling customers is $20 per billing month. The AMI Monitoring Credit shall be applied in billing months in which the customer has charged the Electric Vehicle on three or less days during On-Peak hours. The credit is available for a period of 12 consecutive months and will appear as a separate line item on the customer invoice.

Residential Customers taking service on Residential Smart Hours Rate RSH or Residential Nighttime Savers Rate RPM may enroll in AMI Monitoring without enrolling in the On-Bill Installment Payment Plan.

Interested Residential Customers shall submit an online application on the Company's website to enroll in AMI Monitoring.

Customers participating in AMI Monitoring may earn one $10 AMI Monitoring Credit per participating Electric Vehicle per billing month to encourage Electric Vehicle charging during Off-Peak hours. The AMI Monitoring Credit shall be applied in billing months in which the customer has charged the Electric Vehicle on three or less days during On-Peak Hours. The AMI Monitoring Credit is available for a period of 12 consecutive months and will appear as a separate line item on the customer invoice.

(Continued on Sheet No. C-81.00)

M.P.S.C. No. 14 – Electric

Consumers Energy Company **Sheet No. C-81.00**

(Continued From Sheet No. C-80.00)

C19. TRANSPORTATION ELECTRIFICATION PROGRAMS (TEPS) (Contd)

C19.2. Non-Residential Electric Vehicle Programs

(A) PowerMIDrive Public

(1) Eligibility

This program is available to any Non-residential Customer, either Full Service or Retail Open Access (ROA), that installs a Company-qualified Level 2 or Level 1 electric vehicle supply equipment (EVSE) for at a qualifying overnight or long-term parking options locations available to the public. These are, but not limited to, the following locations: hotels, motels, campgrounds, resorts, airport, train stations and other locations in which the general public can park their electric vehicle overnight or multiple days while charging. Customers who participate in this program may be eligible for a rebate per the terms and conditions located on the Company's website.

Such EVSE must be UL or equivalent safety certified, Energy Star rated and achieve at least a 97% up-time for five years after installation. The EVSE operator may determine the pricing structure and this is not considered Resale. The site must also include clear signage that parking is for EV charging only.

(2) Terms and Conditions

To participate in the program, the customer must comply with all terms and conditions as stated on the Company's website. Applications are not a guarantee of program acceptance or rebate payment. Completed applications will be reviewed in the order received. Rebate funds are reserved for an applicant's project when Consumers Energy sends notice of acceptance to the applicant.

For Full- Service Customers, they must be served on Rate Schedules General Service Secondary Time-of-Use Rate GSTU or General Service Primary Rate GPTU.

For ROA Secondary Customers who choose to participate in the PowerMIDrive Public program, the distribution charges assessed to these customers will be the same as Full-Service customers being served on General Service Secondary Rate GS. ROA Primary Customers will be assessed the same distribution charges as Full-Service customers being served on as Large General Service Primary Rate GPD, but must encourage charging per off-peak hours listed in GSTU or GPTU.

For both Full-Service and ROA customers who own and operate a DC Fast Charging station and participate in the remaining PowerMIDrive DC Fast Charging rebates, they must be served on Rate Schedule General Service Primary Rate GP.

(Continued on Sheet No. C-82.00)

(Continued From Sheet No. C-81.00)

C19. TRANSPORTATION ELECTRIFICATION PROGRAMS (TEPS) (Contd)

C19.2 Non-Residential Electric Vehicle Programs (Contd)

(B) PowerMIFleet

(1) Eligibility

This program is available to any Non-Residential Customer, either Full Service or Retail Open Access, that offer separately metered EVSE for private businesses and their vehicle fleet. These are, but not limited to, the following locations: public transit, non-profit organizations, local governments, small to medium sized businesses and educational facilities. Customers who are selected by the Company to participate in this program may be eligible for a rebate per the terms and conditions located on the Company's website.

Such EVSE must be UL or equivalent safety certified, Energy Star rated and achieve at least a 97% up-time for five years after installation. The EVSE operator may determine the pricing structure and this is not considered Resale.

(2) Terms and Conditions

To participate in the program, the customer must comply with all terms and conditions as stated on the Company's website. Submitting an interest form is not a guarantee of program selection for participation in the program.

Full-Service Customers shall be served on General Service Secondary Time-of-Use Rate GSTU or General Service Primary Rate GPTU.

For ROA Customers who choose to participate in the PowerMIFleet program, the distribution charges assessed to these customers will be the same as Full-Service customers being served on General Service Secondary Rate GS. ROA Primary Customers will be assessed the same distribution charges as Full-Service customers being served on as Large General Service Primary Rate GPD, but must encourage charging per off-peak hours listed in GSTU or GPTU

SECTION D
RATE SCHEDULES

GENERAL TERMS AND CONDITIONS OF THE RATE SCHEDULES

A. Bills for utility service are subject to Michigan State Sales Tax. Customers may file a request with the Company for partial or total exemption from the application of sales tax in accordance with the laws of the State of Michigan and the rules of the Michigan State Department of Treasury.

B. Bills shall be increased within the limits of political subdivisions which levy special taxes, license fees or rentals against the Company's property, or its operation, or the production and/or sale of electric energy, to offset such special charges and thereby prevent other customers from being compelled to share such local increases.

C. Bills shall be increased to offset any new or increased specific tax or excise imposed by any governmental authority upon the Company's generation or sale of electrical energy.

D. A customer that commences service under any of the Company's Rate Schedules thereby agrees to abide by all of the applicable Rules and Regulations contained in this Rate Book for Electric Service.

E. Full Service Customers, applicants for service, or operators with generating facilities on or after June 8, 2012 are required to take service under the Self-Generation Provision (SG) or General Service Self Generation Rate GSG-2.

F. *Non-Residential Customers with load exceeding 1 MW may participate in any regional transmission organization wholesale market program per the terms of the Commission order in Case No. U-21099 dated February 23, 2023. All other* Full Service Customers shall not participate in any regional transmission organization wholesale market program until the Michigan Public Service Commission issues an order authorizing participation.

M.P.S.C. No. 14 – Electric
Consumers Energy Company

Sheet No. D-2.40

SURCHARGES

Rate Schedule	***Investment Recovery Mechanism (IRM) (Case No. U-21389) Effective for service rendered XXXXXX XX, 2024 through XXXXXX XX, 2025***	***Investment Recovery Mechanism (IRM) (Case No. U-21389) Effective for service rendered XXXXXX XX, 2025 through XXXXXX XX, 2026***
Rate RSP	*$0.000150/kWh*	*$0.000424/kWh*
Rate RSH	*$0.000150/kWh*	*$0.000424/kWh*
Rate RPM	*$0.000150/kWh*	*$0.000424/kWh*
Rate RSM	*$0.000150/kWh*	*$0.000424/kWh*
Rate GS	*$0.000119/kWh*	*$0.000337/kWh*
Rate GSTU	*$0.000119/kWh*	*$0.000337/kWh*
Rate GSD	*$0.000084/kWh*	*$0.000237/kWh*
Rate GP		
Customer Voltage Level 1	*$0.000007/kWh*	*$0.000020/kWh*
Customer Voltage Level 2	*$0.000024/kWh*	*$0.000067/kWh*
Customer Voltage Level 3	*$0.000039/kWh*	*$0.000111/kWh*
Rate GPD		
Customer Voltage Level 1	*$0.000005/kWh*	*$0.000014/kWh*
Customer Voltage Level 2	*$0.000017/kWh*	*$0.000048/kWh*
Customer Voltage Level 3	*$0.000028/kWh*	*$0.000078/kWh*
Rate GPTU		
Customer Voltage Level 1	*$0.000005/kWh*	*$0.000014/kWh*
Customer Voltage Level 2	*$0.000017/kWh*	*$0.000048/kWh*
Customer Voltage Level 3	*$0.000028/kWh*	*$0.000078/kWh*
Rate EIP		
Customer Voltage Level 1	*$0.000005/kWh*	*$0.000014/kWh*
Customer Voltage Level 2	*$0.000017/kWh*	*$0.000048 /kWh*
Customer Voltage Level 3	*$0.000028/kWh*	*$0.000078/kWh*
Rate LED		
Customer Voltage Level 1	*$0.000005/kWh*	*$0.000014/kWh*
Customer Voltage Level 2	*$0.000017/kWh*	*$0.000048/kWh*
Customer Voltage Level 3	*$0.000028/kWh*	*$0.000078/kWh*
Rate LTILRR	*N/A*	*N/A*
Rate GSG-2		
Customer Voltage Level 1	*$0.000005/kWh*	*$0.000014/kWh*
Customer Voltage Level 2	*$0.000017/kWh*	*$0.000048/kWh*
Customer Voltage Level 3	*$0.000028/kWh*	*$0.000078/kWh*
Rate GML	*$0.000148/kWh*	*$0.000419/kWh*
Rate GUL	*$0.000743/kWh*	*$0.002101/kWh*
Rate GU-LED	*$0.000743/kWh*	*$0.002101/kWh*
Rate GU	*$0.000047/kWh*	*$0.000132/kWh*
Rate PA	*N/A*	*N/A*
Rate ROA-R	*Same as Full Service Delivery Schedule*	*Same as Full Service Delivery Schedule*
Rate ROA-S	*Same as Full Service Delivery Schedule*	*Same as Full Service Delivery Schedule*
Rate ROA-P	*Same as Full Service Delivery Schedule*	*Same as Full Service Delivery Schedule*

SURCHARGES

Rate Schedule	**Financial Compensation Mechanism Surcharge (Case No. U-20697) Effective for service rendered On and after January 1, 2021**
Rate RSP	$0.000106/kWh
Rate RSH	0.000106/kWh
Rate RPM	0.000106/kWh
Rate RSM	0.000106/kWh
Rate GS	0.000098/kWh
Rate GSTU	0.000098/kWh
Rate GSD	0.000099/kWh
Rate GP	
Customer Voltage Level 1	0.000079/kWh
Customer Voltage Level 2	0.000086/kWh
Customer Voltage Level 3	0.000091/kWh
Rate GPD	
Customer Voltage Level 1	0.000081/kWh
Customer Voltage Level 2	0.000088/kWh
Customer Voltage Level 3	0.000094/kWh
Rate GPTU	
Customer Voltage Level 1	0.000080/kWh
Customer Voltage Level 2	0.000087/kWh
Customer Voltage Level 3	0.000092/kWh
Rate EIP	
Customer Voltage Level 1	0.000072/kWh
Customer Voltage Level 2	0.000078/kWh
Customer Voltage Level 3	0.000083/kWh
Rate LED	
Customer Voltage Level 1	NA
Customer Voltage Level 2	NA
Customer Voltage Level 3	NA
Rate LTILRR	NA
Rate GSG-2	
Customer Voltage Level 1	0.000089/kWh
Customer Voltage Level 2	0.000097/kWh
Customer Voltage Level 3	0.000102/kWh
Rate GML	0.000111/kWh
Rate GUL	0.000111/kWh
Rate GU-LED	0.000111/kWh
Rate GU	0.000096/kWh
Rate PA	NA
Rate ROA-R	NA
Rate ROA-S	NA
Rate ROA-P	NA

M.P.S.C. No. 14 – Electric
Consumers Energy Company

Sheet No. D-5.00

SURCHARGES

Rate Schedule	Electric Rate Case Deferral Surcharge (Case No. U-21224) Effective for service rendered January 20, 2023 through January 19, 2024	*Electric Rate Case Deferral Surcharge (Case No. U-21389) Effective for service rendered XXXXXX XX, 2024 through XXXXXX XX, 2025*	U-21224 Refund (Case No. U-21224) Effective for service rendered January 20, 2023 through January 19, 2024
Rate RSP	$0.000309/kWh	*$0.000430/kWh*	$(0.000423)/kWh
Rate RSH	0.000309/kWh	*0.000430/kWh*	(0.000423)/kWh
Rate RPM	0.000309/kWh	*0.000430/kWh*	(0.000423)/kWh
Rate RSM	0.000309/kWh	*0.000430/kWh*	(0.000423)/kWh
Rate GS	0.000228/kWh	*0.000342/kWh*	(0.000406)/kWh
Rate GSTU	0.000228/kWh	*0.000342/kWh*	(0.000406)/kWh
Rate GSD	0.000160/kWh	*0.000240/kWh*	(0.000207)/kWh
Rate GP			
Customer Voltage Level 1	0.000014/kWh	*0.000021/kWh*	(0.001156)/kWh
Customer Voltage Level 2	0.000049/kWh	*0.000068/kWh*	(0.001156)/kWh
Customer Voltage Level 3	0.000081/kWh	*0.000112/kWh*	(0.001156)/kWh
Rate GPD			
Customer Voltage Level 1	0.000010/kWh	*0.000015/kWh*	(0.000285)/kWh
Customer Voltage Level 2	0.000035/kWh	*0.000049/kWh*	(0.000285)/kWh
Customer Voltage Level 3	0.000058/kWh	*0.000080/kWh*	(0.000285)/kWh
Rate GPTU			
Customer Voltage Level 1	0.000010/kWh	*0.000015/kWh*	(0.000991)/kWh
Customer Voltage Level 2	0.000035/kWh	*0.000049/kWh*	(0.000991)/kWh
Customer Voltage Level 3	0.000058/kWh	*0.000080/kWh*	(0.000991)/kWh
Rate EIP			
Customer Voltage Level 1	0.000010/kWh	*0.000015/kWh*	(0.000260)/kWh
Customer Voltage Level 2	0.000035/kWh	*0.000049/kWh*	(0.000260)/kWh
Customer Voltage Level 3	0.000058/kWh	*0.000080/kWh*	(0.000260)/kWh
Rate LED			
Customer Voltage Level 1	0.000010/kWh	*0.000015/kWh*	NA
Customer Voltage Level 2	0.000035/kWh	*0.000049/kWh*	NA
Customer Voltage Level 3	0.000058/kWh	*0.000080/kWh*	NA
Rate LTILRR	N/A	*N/A*	NA
Rate GSG-2			
Customer Voltage Level 1	0.000010/kWh	*0.000015/kWh*	(0.000004)/kWh
Customer Voltage Level 2	0.000035/kWh	*0.000049/kWh*	(0.000156)/kWh
Customer Voltage Level 3	0.000058/kWh	*0.000080/kWh*	(0.002017)/kWh
Rate GML	0.000271/kWh	*0.000425/kWh*	(0.001129)/kWh
Rate GUL	0.001306/kWh	*0.002131/kWh*	(0.004352)/kWh
Rate GU-LED	0.001306/kWh	*0.002131/kWh*	(0.004352)/kWh
Rate GU	0.000093/kWh	*0.000133/kWh*	(0.000414)/kWh
Rate PA		*N/A*	NA
Rate ROA-R	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*	
Rate ROA-S	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*	
Rate GSD			(0.000200)/kWh
Rate ROA-P	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*	
Rate GP			
Customer Voltage Level 3			(0.000012)/kWh
Rate GPD			
Customer Voltage Level 1			(0.000010)/kWh
Customer Voltage Level 2			(0.000030)/kWh
Customer Voltage Level 3			(0.000114)/kWh

RATE CATEGORIES AND PROVISIONS

Description	Full Service	Retail Open Access
RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP		
Residential	1001	Not Applicable
Provisions		
Residential Summer On-Peak Basic With Income Assistance (RIA) *	Applicable	Not Applicable
Residential Summer On-Peak Basic With Low Income Assistance Credit (LIAC) *	Applicable	Not Applicable
Residential Summer On-Peak Basic With Senior Citizen (RSC) *	Applicable	Not Applicable
Device Cycling Program	Applicable	Not Applicable
Peak Reward ***	Applicable	Not Applicable
Critical Peak Pricing ***	Applicable	Not Applicable
Residential Summer On-Peak Basic With Self-Generation (SG) **	1700	Not Applicable
Net Metering Program	Applicable	Not Applicable
Distributed Generation Program	Applicable	Not Applicable
Green Generation Program ****	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
RESIDENTIAL SMART HOURS RATE RSH		
Residential	1040	Not Applicable
Provisions		
Residential Smart Hours With Income Assistance (RIA) *	Applicable	Not Applicable
Residential Smart Hours With Low Income Assistance Credit (LIAC) *	Applicable	Not Applicable
Residential Smart Hours With Senior Citizen (RSC) *	Applicable	Not Applicable
Device Cycling Program	Applicable	Not Applicable
Peak Reward ***	Applicable	Not Applicable
Critical Peak Pricing ***	Applicable	Not Applicable
Residential Smart Hours With Self-Generation (SG) **	1702	Not Applicable
Net Metering Program	Applicable	Not Applicable
Distributed Generation Program	Applicable	Not Applicable
Green Generation Program ****	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Residential Electric Vehicle Program	Applicable	Not Applicable
RESIDENTIAL NIGHTTIME SAVERS RATE RPM		
Residential	1050	Not Applicable
Provisions		
Residential Nighttime Savers With Income Assistance (RIA) *	Applicable	Not Applicable
Residential Nighttime Savers With Low Income Assistance Credit (LIAC) *	Applicable	Not Applicable
Residential Nighttime Savers With Senior Citizen (RSC) *	Applicable	Not Applicable
Residential Nighttime Savers – Plug-In Electric Vehicle Only Credit	Applicable	Not Applicable
Device Cycling Program	Applicable	Not Applicable
Peak Reward ***	Applicable	Not Applicable
Critical Peak Pricing ***	Applicable	Not Applicable
Residential Nighttime Savers With Self-Generation (SG) **	1703	Not Applicable
Net Metering Program	Applicable	Not Applicable
Distributed Generation Program	Applicable	Not Applicable
Green Generation Program ****	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Residential Electric Vehicle Program	Applicable	Not Applicable
RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM		
Residential	1000	Not Applicable
Provisions		
Residential Non-Transmitting Meter With Income Assistance (RIA) *	Applicable	Not Applicable
Residential Non-Transmitting Meter With Low Income Assistance Credit (LIAC) *	Applicable	Not Applicable
Residential Non-Transmitting Meter With Senior Citizen (RSC) *	Applicable	Not Applicable
Green Generation Program ****	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable

* Provisions shall not be taken in conjunction with each other.
** Provisions shall not be taken in conjunction with the Net Metering Program or the Distributed Generation Program.
*** Peak Reward and/or Device Cycling Program shall not be taken in conjunction with Critical Peak Pricing.
**** Closed to new customers, effective April 5, 2019.

(Continued on Sheet No. D-10.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Sheet No. D-10.00**

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-9.00)

Description	Full Service	Retail Open Access
GENERAL SERVICE SECONDARY RATE GS		
Commercial	1100	2100
Commercial – Temporary Construction Service	1999	Not Applicable
Provisions		
Commercial Billboards/Outdoor Advertising Signs – Dusk to Dawn	Applicable	Not Applicable
Commercial Billboards/Outdoor Advertising Signs – Fixed Hours of Operation	Applicable	Not Applicable
Commercial Miscellaneous	Applicable	Not Applicable
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG) *	1715	Not Applicable
Net Metering Program	Applicable	Applicable
Distributed Generation Program	Applicable	Applicable
Demand Response Program	Applicable	Not Applicable
Green Generation Program **	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Non-Residential Electric Vehicle Programs	*Not Applicable*	*Applicable*
GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU		
Commercial	1121	Not Applicable
Provisions		
Commercial With Educational Institution (GEI)	Applicable	Not Applicable
Commercial With Interruptible Provision (GSI)	Applicable	Not Applicable
Commercial With Self-Generation (SG) *	1716	Not Applicable
Distributed Generation Program	Applicable	Applicable
Demand Response Program	Applicable	Not Applicable
Commercial Resale	Applicable	Not Applicable
Green Generation Program **	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Non-Residential Electric Vehicle Programs	*Applicable*	*Not Applicable*
GENERAL SERVICE SECONDARY DEMAND RATE GSD		
Commercial	1120	2120
Commercial (100 kW Billing Demand Guarantee)	1140	2140
Provisions		
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Interruptible Provision (GSI)	Applicable	Not Applicable
Commercial With Self-Generation (SG) *	1725	Not Applicable
Commercial (100 kW Billing Demand Guarantee) With Self-Generation (SG) *	1735	Not Applicable
Net Metering Program	Applicable	Applicable
Distributed Generation Program	Applicable	Applicable
Demand Response Program	Applicable	Not Applicable
Green Generation Program **	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable

*Provisions shall not be taken in conjunction with the Net Metering Program or Distributed Generation Program.
** Closed to new customers, effective April 5, 2019.

(Continued on Sheet No. D-11.00)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-10.00)

Description	Full Service	Retail Open Access
GENERAL SERVICE PRIMARY RATE GP		
Commercial (Customer Voltage Level 1, 2 or 3)	1200	2200
Industrial (Customer Voltage Level 1, 2 or 3)	1210	2210
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI)	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1745	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1750	Not Applicable
Net Metering Program	Applicable	Applicable
Distributed Generation Program	Applicable	Applicable
Demand Response Program	Applicable	Not Applicable
Green Generation Program ***	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Non-Residential Electric Vehicle Programs	*Applicable*	*Applicable*
LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD		
Commercial (Customer Voltage Level 1, 2 or 3)	1220	2220
Industrial (Customer Voltage Level 1, 2 or 3)	1230	2230
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP) **	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP) **	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI) **	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI) **	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1755	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1760	Not Applicable
Net Metering Program	Applicable	Applicable
Distributed Generation Program	Applicable	Applicable
Demand Response Program	Applicable	Not Applicable
Green Generation Program ***	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Non-Residential Electric Vehicle Programs	*Not Applicable*	*Applicable*
GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU		
Commercial (Customer Voltage Level 1, 2, or 3)	1280	Not Applicable
Industrial (Customer Voltage Level 1, 2, or 3)	1285	Not Applicable
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Not Applicable
Commercial with Education Institution (GEI)	Applicable	Not Applicable
Industrial with Education Institution (GEI)	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1765	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1770	Not Applicable
Net Metering Program	Applicable	Not Applicable
Distributed Generation Program	Applicable	Not Applicable
Demand Response Program	Applicable	Not Applicable
Green Generation Program ***	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Non-Residential Electric Vehicle Programs	*Applicable*	*Not Applicable*

** Provisions shall not be taken in conjunction with the Net Metering Program or Distributed Generation Program.
*** Closed to new customers, effective April 5, 2019.

(Continued on Sheet No. D-12.00)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

Availability:

Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purpose of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution System, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 – Non-Transmitting Meter Provision participants.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$0.086217	*0.005990*	*$0.092207*	per kWh for Off-Peak kWh between June 1 and September 30
$0.132271	*$0.008912*	*$0.141183*	per kWh for On-Peak kWh between June 1 and September 30
$0.082887	*$0.004667*	*$0.087554*	per kWh for all kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:	$8.00	per customer per month
Distribution Charge:	*$0.074267*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-15.00)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Device Cycling Program:

A customer who is taking service from the Company may be eligible to participate in the Company's voluntary Device Cycling Program for load management of eligible electric equipment, including air conditioning~~,~~ *and* water heaters. Customer eligibility to participate is determined solely by the Company~~.~~ *and* Device Cycling Program Credits may be taken in conjunction with one another. The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company *or with a contractual agreement with a landlord if the customer is not the property owner*. The Company will install the required equipment *at* the premises which will allow *l*oad *m*anagement upon signal from the Company. When *l*oad *m*anagement equipment is installed at a premises, future customers will be auto-enrolled into the Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

*Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's credit earned from their incremental energy savings through Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month***.**

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service. *The Company reserves the right to call test events between October 1 and May 31 for customers participating in the Device Cycling Program.*

Load *m*anagement may occur *on non-holiday weekdays* between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day *throughout the year for customers with water heater equipment, while customers with air conditioning equipment will experience load management during the summer billing months of June through September only*. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load *m*anagement may *occur on any day, during any hour, and for any length of time* during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a *l*oad *m*anagement event for one *l*oad *m*anagement event during the June through September months in any one calendar year for the balance of the hours left in that *l*oad *m*anagement event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June – September
Water Heater Cycling Credit:	$ *(1.88)*	per customer per month for all billing months

(Continued on Sheet No. D-17.00)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-16.00)

Monthly Rate: (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions. *Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.*

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$(1.00)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event. *Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.*

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount:	$*(0.019625)*	per kWh of Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-18.00)

RESIDENTIAL SMART HOURS RATE RSH

Availability:

Subject to any restrictions, this rate is available to any Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, maintain and own the required equipment at the customers' premises at the Company's request. By selecting this rate schedule, the customer agrees to provide an email address. Electric consumption is billed using on-peak and off-peak periods year-round on the Residential Smart Hours Rate.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	*$0.086217*	*$0.005990*	*$0.092207*	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak – Summer	*$0.132271*	*$0.008912*	*$0.141183*	per kWh for all On-Peak kWh between June 1 and September 30
Off-Peak – Winter	*$0.080987*	*$0.004518*	*$0.085505*	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak – Winter	*$0.091448*	*$0.005139*	*$0.096587*	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	*$0.074267*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-36.10)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.10)

Monthly Rate: (Contd)

Device Cycling Program:

A customer who is taking service from the Company may be eligible to participate in the Company's voluntary Device Cycling Program for load management of eligible electric equipment, including air conditioning~~,~~ *and* water heaters. Customer eligibility to participate is determined solely by the Company~~.~~ *and* Device Cycling Program Credits may be taken in conjunction with one another. The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company *or with a contractual agreement with a landlord if the customer is not the property owner*. The Company will install the required equipment *at* the premises which will allow *l*oad *m*anagement upon signal from the Company. When *l*oad *m*anagement equipment is installed at a premises, future customers will be auto-enrolled into the Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's credit earned from their incremental energy savings through Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service. *The Company reserves the right to call test events between October 1 and May 31 for customers participating in the Device Cycling Program*

Load *m*anagement may occur *on non-holiday weekdays* between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day *throughout the year for customers with water heater equipment, while customers with air conditioning equipment will experience load management during the summer billing months of June through September only*. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load *m*anagement may *occur on any day, during any hour, and for any length of time* during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a *l*oad *m*anagement event for one *l*oad *m*anagement event during the June through September months in any one calendar year for the balance of the hours left in that *l*oad *m*anagement event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June-September
Water Heater Cycling Credit	$*(1.88)*	per customer per month for all billing months

(Continued on Sheet No. D-38.00)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-37.00)

Monthly Rate: (Contd)

Peak Reward:

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward Enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions. *Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program*.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward	$(1.00)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event. *Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.*

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount	$*(0.019625)*	per kWh for Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-39.00)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-38.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2., Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2., Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Residential Electric Vehicle Program:

The Residential Electric Vehicle Program is available to any eligible customer as described in Rule *C19.1*., Residential Electric Vehicle Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, including weekday holidays when applicable:

Summer: June 1 through September 30

Winter: October 1 through May 31

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract.

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

Availability:

The Residential Nighttime Savers Rate is voluntary and available for service rendered on and after June 1, 2021 to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this program only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Super Off-Peak - Summer	*$0.072763*	*$0.004114*	*$0.076876*	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Summer	*$0.096349*	*$0.006757*	*$0.103106*	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	*$0.132271*	*$0.008912*	*$0.141183*	per kWh for all On-Peak kWh between June 1 and September 30
Super Off-Peak - Winter	*$0.070063*	*$0.003564*	*$0.073627*	per kWh for all Super Off-Peak kWh between *October 1 and May 31*
Off-Peak - Winter	*$0.091004*	*$0.004969*	*$0.095973*	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	*$0.091448*	*$0.005139*	*$0.096587*	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge: $8.00 per customer per month

Distribution Charge: $*0.074267* per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-40.50)

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Sheet No. D-41.00**

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.50)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) and shall not be applied to more than one account per Principal Residence Customer.

Residential Plug-In Electric Vehicle Only Credit (REV):

When service is supplied for Level 2 Charging of a separately metered electric vehicle, a credit shall be applied during all billing months. Electric usage for the separately metered electric vehicle will be billed under the Residential Nighttime Savers Rate.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 50 amperes or 9.6 kW.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this credit. Low-speed electric vehicles including golf carts are not eligible for this credit 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 this credit.

Delivery Charges: These charges are applicable to Full Service Customers.

Residential Plug-In Electric Vehicle Only Credit: $(8.00) per customer per month

Device Cycling Program:

A customer who is taking service from the Company may be eligible to participate in the Company's voluntary-Device Cycling Program for load management of eligible electric equipment, including air conditioning~~,~~ *and* water heaters. Customer eligibility to participate is determined solely by the Company~~.~~ *and* Device Cycling Program Credits may be taken in conjunction with one another. The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company *or with a contractual agreement with a landlord if the customer is not the property owner*. The Company will install the required equipment *at* the premises which will allow *l*oad *m*anagement upon signal from the Company. When *l*oad *m*anagement equipment is installed at a premises, future customers will be auto-enrolled into the Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

*Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's credit earned from their incremental energy savings through Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month***.**

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service. *The Company reserves the right to call test events between October 1 and May 31 for customers participating in the Device Cycling Program*

(Continued on Sheet No. D-42.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-41.00)

Monthly Rate: (Contd)

Device Cycling Program: (Contd)

Load *m*anagement may occur *on non-holiday weekdays* between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day *throughout the year for customers with water heater equipment, while customers with air conditioning equipment will experience load management during the summer billing months of June through September only*. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load *m*anagement may *occur on any day, during any hour, and for any length of time* during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a *l*oad *m*anagement event for one *l*oad *m*anagement event during the June through September months in any one calendar year for the balance of the hours left in that *l*oad *m*anagement event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June-September
Water Heater Cycling Credit:	$*(1.88)*	per customer per month for all billing months

Peak Reward:

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward Enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions. *Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.*

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward	$(1.00)	per kWh of incremental energy reduction during a critical peak event

(Continued on Sheet No. D-43.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-42.00)

Monthly Rate: (Contd)

Critical Peak Price:

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customer who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event. *Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.*

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount	$*(0.019625)*	per kWh for Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provision contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-44.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-43.00)

Monthly Rate: (Contd)

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Residential Electric Vehicle Program:

The Residential Electric Vehicle Program is available to any eligible customer as described in Rule *C19.1.*, Residential Electric Vehicle Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of Hours:

The following schedule shall apply Monday through Friday including weekday holidays.

Summer: June 1 through September 30
Winter: October 1 through May 31

(1)	Super Off-Peak Hours:	11:00 PM to 6:00 AM
(2)	Off-Peak Hours:	6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM
(3)	On-Peak Hours:	2:00 PM to 7:00 PM

Saturday and Sunday are Super Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

Availability:

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is only available to customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision, customers with a Non-Communicating Advanced Metering Infrastructure (AMI) Meter, or customers determined to be eligible at the Company's sole discretion.

A Non-Communicating AMI meter is unable to consistently transmit interval data to the Company's billing system. Non-Communicating Meters are determined at the Company's sole discretion and are subject to a minimum of one communication review per calendar year. When the meter has been determined to successfully communicate interval data, the customer will be notified and transferred to Residential Service Secondary On-Peak Summer Basic Rate RSP. The transfer to Rate RSP shall not occur between June 1 and September 30.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$0.082887	*$0.004667*	*$0.087554*	per kWh for the first 600 kWh per month during the billing months of June - September
$0.132271	*$0.008912*	*$0.141183*	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$0.082887	*$0.004667*	*$0.087554*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-44.20)

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Consumers Energy Company

Sheet No. D-44.20

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.10)

Monthly Rate: (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.074267*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following in the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

(Continued on Sheet No. D-44.30)

GENERAL SERVICE SECONDARY RATE GS

Availability:

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$0.094566	*$0.006246*	*$0.100813*	per kWh for all kWh during the billing months of June-September
$0.082686	*$0.004372*	*$0.087058*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.057594*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Billboard Service Provision:

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-46.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-45.00)

Monthly Rate: (Contd)

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "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 located on the same campus and used to impart instruction, including all adjacent and appurtenant 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.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit: $*(0.000848)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill *or a check* for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-47.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-46.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-residential Electric Vehicle Programs.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Net Metering Program, (vii) service under the Demand Response Program or (viii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Sheet No. D-48.00**

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems. Standby service shall be provided on this rate for secondary customers with solar installations equal to or greater than 150 kW.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with any other Demand Response Program or Net Metering.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.073219*	*$0.004064*	*$0.077283*	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak-Summer	*$0.098056*	*$0.006297*	*$0.104353*	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak-Summer	*$0.132114*	*$0.007579*	*$0.139692*	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Winter	*$0.071813*	*$0.003541*	*$0.075354*	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak -Winter	*$0.091061*	*$0.004740*	*$0.095801*	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.057594*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-49.00)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-48.00)

Monthly Rate (Contd)

Schedule of Hours

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year's Day – January 1, Memorial Day – Last Monday in May, Independence Day – July 4, Labor Day – First Monday in September, Thanksgiving Day – Fourth Thursday in November and Christmas Day – December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

(1) Off-Peak Hours 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
(2) Mid-Peak Hours 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
(3) On-Peak Hours 2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

(1) Off-Peak Hours 11:00 PM to 7:00 AM
(2) On-Peak Hours 7:00 AM to 11:00 PM

Resale Service Provision

Subject to any restrictions, the provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "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 located on the same campus and used to impart instruction, including all adjacent and appurtenant 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.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Education Institution Credit: $*(0.000848)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. 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.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

(Continued on Sheet No. D-50.00)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-49.00)

Monthly Rate: (Contd)

General Service Secondary Interruptible (GSI) Provision: (Contd)

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges – These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit: $ *(0.017673)* per kWh for all kWh

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill *or a check* for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

(Continued on Sheet No. D-50.10)

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Sheet No. D-50.10**

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-50.00)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Demand Response Program or (vii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability:

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These Charges are applicable to Full Service customers.

Peak Demand Charge:

Non-Capacity	Capacity	Total	
$25.90	*$1.68*	*$27.58*	per kW for all kW of Peak Demand during the billing months of June-September
$15.05	*$1.50*	*$16.55*	per kW for all kW of Peak Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$0.032155	per kWh for all kWh during the billing months of June-September
$0.029962	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factors shown on Sheet No. D-6.00.

Delivery Charges: These Charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$1.00	per kW for all kW of Peak Demand
Distribution Charge:	$ *0.043515*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-52.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-52.00)

Monthly Rate: (Contd)

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "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 located on the same campus and used to impart instruction, including all adjacent and appurtenant 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.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit: $ *(0.000690)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. 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.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electric Procedure or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges – These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW for all kW of Peak Demand during the billing months of June - September
	$(6.00)	per kW for all kW of Peak Demand during the billing months of October - May

(Continued on Sheet No. D-53.50)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-53.00)

Monthly Rate: (Contd)

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill *or a check* for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

(Continued on Sheet No. D-54.00)

GENERAL SERVICE PRIMARY RATE GP

Availability:

As of January 1, 2021, this rate is closed to new business other than for service to DCFC fast charging stations.

Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.089336	*$0.005350*	*$0.094686*	per kWh for all kWh during the billing months of June-September
$0.078143	*$0.003745*	*$0.081888*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.088260	*$0.005267*	*$0.093527*	per kWh for all kWh during the billing months of June-September
$0.077219	*$0.003687*	*$0.080905*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.087186	*$0.005192*	*$0.092378*	per kWh for all kWh during the billing months of June-September
$0.076290	*$0.003634*	*$0.079924*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-56.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-55.00)

Monthly Rate (Contd)

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)

Distribution Charge: *$0.020826* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)

Distribution Charge: *$0.009094* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)

Distribution Charge: *$0.002634* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period . Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-57.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-56.00)

Monthly Rate (Contd)

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $ *(0.001741)* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $ *(0.001309)* per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "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 located on the same campus and used to impart instruction, including all adjacent and appurtenant 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.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Educational Institution Credit: $(0.000533) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill *or a check* for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-58.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-57.00)

Monthly Rate (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

For customers with monthly demands of 300 kW or more, all service under this rate may require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Green Generation Program, (ii) service under the Educational Institution provision, (iii) service under the Resale Service Provision, (iv) service under the Net Metering Program, (v) service under the Demand Response Program or (vi) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Demand Charge:

Capacity	Non-Capacity	Total	
$16.50	*$1.82*	*$18.32*	per kW of On-Peak Billing Demand during the billing months of June-September
$14.26	*$1.68*	*$15.94*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$8.17	per kW of On-Peak Billing Demand during the billing months of June-September
$7.60	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$0.045478	per kWh for all On-Peak kWh during the billing months of June-September
$0.029052	per kWh for all Off-Peak kWh during the billing months of June-September
$0.034759	per kWh for all On-Peak kWh during the billing months of October-May
$0.030292	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-60.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-59.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service customers. (Contd)

Charges for Customer Voltage Level 2 (CVL2)

Demand Charge:

Capacity	Non-Capacity	Total	
$16.32	*$1.79*	*$18.11*	per kW of On-Peak Billing Demand during the billing months of June-September
$14.10	*$1.66*	*$15.76*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$8.04	per kW of On-Peak Billing Demand during the billing months of June-September
$7.49	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$0.044980	per kWh for all On-Peak kWh during the billing months of June-September
$0.028734	per kWh for all Off-Peak kWh during the billing months of June-September
$0.034378	per kWh for all On-Peak kWh during the billing months of October-May
$0.029960	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Demand Charge:

Capacity	Non-Capacity	Total	
$16.14	*$1.76*	*$17.90*	per kW of On-Peak Billing Demand during the billing months of June-September
$13.94	*$1.63*	*$15.58*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$7.93	per kW of On-Peak Billing Demand during the billing months of June-September
$7.38	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$0.044464	per kWh for all On-Peak kWh during the billing months of June-September
$0.028405	per kWh for all Off-Peak kWh during the billing months of June-September
$0.033984	per kWh for all On-Peak kWh during the billing months of October-May
$0.029617	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-61.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-60.00)

Monthly Rate: (Contd)

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	*$5.93*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	*$3.09*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	*$0.90*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-62.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-61.00)

Monthly Rate: (Contd)

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand:

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $*(0.73)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $*(0.55)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-63.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-62.00)

Monthly Rate: (Contd)

Aggregate Peak Demand Service Provision (GAP):

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "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 located on the same campus and used to impart instruction, including all adjacent and appurtenant 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.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Educational Institution Credit:	$*(0.000176)*	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill *or a check* for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-64.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-63.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI):

This provision is available to any customer account willing to either (1) contract for at least *250* kW of On-Peak Billing Demand as interruptible or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment. Customers served under Rate GPD shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may provide the Customer equipment to provide real-time, Internet-enabled power monitoring. If such monitoring is provided, the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand

For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may adjust the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

(Continued on Sheet No. D-65.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-65.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Contd)

Monthly Billing

For billing purposes, the Contracted Firm Capacity will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges - These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)

LMP Energy Charge	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	*$0.037344*	per kWh for all kWh during the billing months of June-September
	$0.034536	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

LMP Energy Charge	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	*$0.036388*	per kWh for all kWh during the billing months of June-September
	$0.032644	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL 1)

LMP Energy Charge	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	*$0.032627*	per kWh for all kWh during the billing months of June-September
	$0.029091	per kWh for all kWh during the billing months of October-May

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	*0.992%*
Customer Voltage Level 2	*1.313%*	*2.239%*
Customer Voltage Level 3	*3.366%*	*6.948%*

Delivery Charges – These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge:

If contracted capacity is separately metered: $100.00 per additional meter installation per month

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00 as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

(Continued on Sheet No. D-67.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

(Continued on Sheet No. D-69.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
Sheet No. D-71.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-70.00)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.067290*	*$0.003182*	*$0.070472*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.082595*	*$0.004711*	*$0.087306*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.108883*	*$0.005866*	*$0.114748*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.124771*	*$0.006145*	*$0.130916*	per kWh during the calendar months of June-September
Off-Peak -Winter	*$0.073740*	*$0.003391*	*$0.077132*	per kWh during the calendar months of October-May
Mid-Peak -Winter	*$0.082502*	*$0.003941*	*$0.086443*	per kWh during the calendar months of October-May
High-Peak -Winter	*$0.087588*	*$0.003942*	*$0.091530*	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.066492*	*$0.003133*	*$0.069625*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.081601*	*$0.004638*	*$0.086239*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.107579*	*$0.005775*	*$0.113354*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.123288*	*$0.006050*	*$0.129338*	per kWh during the calendar months of June-September
Off-Peak - Winter	*$0.072868*	*$0.003339*	*$0.076207*	per kWh during the calendar months of October-May
Mid-Peak - Winter	*$0.081524*	*$0.003880*	*$0.085403*	per kWh during the calendar months of October-May
High-Peak - Winter	*$0.086553*	*$0.003881*	*$0.090435*	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.065692*	*$0.003088*	*$0.068781*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.080610*	*$0.004572*	*$0.085182*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.106276*	*$0.005693*	*$0.111968*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.121802*	*$0.005963*	*$0.127765*	per kWh during the calendar months of June-September
Off-Peak - Winter	*$0.071993*	*$0.003291*	*$0.075284*	per kWh during the calendar months of October-May
Mid-Peak - Winter	*$0.080542*	*$0.003824*	*$0.084366*	per kWh during the calendar months of October-May
High-Peak - Winter	*$0.085514*	*$0.003826*	*$0.089340*	per kWh during the calendar months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$*5.93*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$*3.09*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$*0.90*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-72.00)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-71.00)

Monthly Rate (Contd)

Adjustment for Power Factor (Contd)

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)		
Substation Ownership Credit:	$*(0.73)*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL 1)		
Substation Ownership Credit:	$*(0.55)*	per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, “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 located on the same campus and used to impart instruction, including all adjacent and appurtenant 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.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Educational Institution Credit:	$ *(0.000176)*	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-72.10)

M.P.S.C. No. 14 – Electric
Consumers Energy Company

Sheet No. D-72.10

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.00)

Monthly Rate (Contd)

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill *or a check* for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Interruptible Service Provision (GI):

This provision is available to any customer account willing to either (1) contract for at least *250* kW of On-Peak Billing Demand as interruptible or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity. *For customers who participate in the Interruptible Service Provision (GI) on this Rate Schedule, the On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use within on-peak hours during the billing month as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates. For customers who are not enrolled in the GI Provision, the On-Peak Billing Demand shall not apply.*

The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment. Customers served under Rate *GPTU* shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may provide the Customer equipment to provide real-time, Internet-enabled power monitoring. If such monitoring is provided the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand

For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

(Continued on Sheet No. D-72.20)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.20)

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.
A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Service under this rate may require a written contract with a minimum term of one year. Service under this rate shall require a written contract for (i) service under the Educational Institution Service Provision, (ii) service under the Interruptible Service Provision, (iii) service under the Demand Response Program, or (iv) at the option of the Company.

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.00)

Critical Peak Event Determination

A Critical Peak Event *occurs when* the market price *exceeds* an Economic Trigger Price or a *S*ystem *I*ntegrity *E*vent is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources. The Company shall provide notice of a System Integrity Event by telephone to the contact numbers provided by the Customer. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed at $1.00 per kWh during the duration of the event.

The Summer Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 3:00 PM to 5:00 PM for the period of June 1 through September 30 of the previous year. The Summer Economic Trigger Price will be set on January 30 of each year by the Company.

The Winter Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 5:00 PM to 7:00 PM for the period of October 1 through May 31 of the previous year. The Winter Economic Trigger Price will be set on July 31 of each year by the Company.

Energy Intensive Primary Rate customers will be notified after the Summer and Winter Economic Trigger Prices are set. The Company shall endeavor to provide notice in advance of a probable System Integrity Event.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event
Winter:	
Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

(Continued on Sheet No. D-75.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Sheet No. D-75.00**

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.50)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.066901*	*$0.002547*	*$0.069448*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.088051*	*$0.003980*	*$0.092031*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.113409*	*$0.004839*	*$0.118248*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.128630*	*$0.004950*	*$0.133580*	per kWh during the calendar months of June-September
Interruptible Credit	*$(0.000000)*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September
Off-Peak-Winter	*$0.074119*	*$0.002771*	*$0.076889*	per kWh during the calendar months of October-May
Mid-Peak-Winter	*$0.085645*	*$0.003162*	*$0.088806*	per kWh during the calendar months of October-May
High-Peak-Winter	*$0.089524*	*$0.003205*	*$0.092728*	per kWh during the calendar months of October-May
Interruptible Credit	*$(0.000000)*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of October-May*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of October-May
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.066112*	*$0.002507*	*$0.068620*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.086999*	*$0.003918*	*$0.090917*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.112060*	*$0.004764*	*$0.116824*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.127112*	*$0.004874*	*$0.131986*	per kWh during the calendar months of June-September
Interruptible Credit	*$(0.000000)*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	*$0.073246*	*$0.002728*	*$0.075974*	per kWh during the calendar months of October-May
Mid-Peak-Winter	*$0.084637*	*$0.003113*	*$0.087750*	per kWh during the calendar months of October-May
High-Peak-Winter	*$0.088473*	*$0.003155*	*$0.091628*	per kWh during the calendar months of October-May
Interruptible Credit	*$(0.000000)*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of October-May*
Emergency Event	NA	$1.00	$1.00	per kWh during a System Integrity Event during the calendar months of October-May
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

(Continued on Sheet No. D-76.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company

Sheet No. D-76.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-75.00)

Monthly Rate (Contd):

Power Supply Charges: (Contd)

Charges for Customer Voltage Level 1(CVL1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.065319*	*$0.002472*	*$0.067791*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.085947*	*$0.003862*	*$0.089809*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.110709*	*$0.004696*	*$0.115405*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.125587*	*$0.004804*	*$0.130391*	per kWh during the calendar months of June-September
Interruptible Credit	*$(0.000000)*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	*$0.072368*	*$0.002689*	*$0.075057*	per kWh during the calendar months of October-May
Mid-Peak-Winter	*$0.083623*	*$0.003068*	*$0.086691*	per kWh during the calendar months of October-May
High-Peak-Winter	*$0.087414*	*$0.003110*	*$0.090524*	per kWh during the calendar months of October-May
Interruptible Credit	*$(0.000000)*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of October-May*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of October-May
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$*5.93*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$*3.09*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$*0.90*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-77.00)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-76.00)

Monthly Rate (Contd):

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Interruptible Credit:

Due to the nature of this rate schedule, all customers on this rate schedule shall receive an Interruptible Credit per kWh for all consumption for each calendar month.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $*(0.73)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $*(0.55)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-78.00)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Where voltage is supplied at a nominal voltage of 25,000 volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, from the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered production capacity, transmission capacity and energy to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission as reflected in the Monthly Rate.

Monthly Rate:

System Contribution Charge:	$0.000284	per kWh for all kWh

Power Supply Charges:

Production Charge:		
Customer Voltage Level 1	$4.73	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$4.81	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$4.86	per kW of On-Peak Billing Demand for all calendar months
Transmission Charge:		
Customer Voltage Level 1	$1.59	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$1.62	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$1.64	per kW of On-Peak Billing Demand for all calendar months

The monthly Transmission Charge is based on the incremental transmission charges applicable with the load served under this tariff and shall be adjusted and reconciled on an annual basis in the Company's PSCR proceedings.

Energy Charge: For all energy supplied by the Company, the customer shall be responsible for *either* the MISO Real-Time *or Day Ahead* Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh) *Customers also enrolled in the Voluntary Large Customer Renewable Program LC-REP (LC-REP) may choose, at the Company's discretion, to have the billing of energy under this Rate Schedule match with the crediting methodology of energy under the LC-REP Program for administrative purposes.*

Line losses applied to Energy Charge	
Voltage Level 1	*2.98%*
Voltage Level 2	*4.14%*
Voltage Level 3	*5.26%*

(Continued on Sheet No. D-78.30)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.20)

Monthly Rate: (Contd)

Delivery Charges:

Distribution Charges:

Customer Voltage Level 1:	$*0.90*	per kW of Maximum Demand
Customer Voltage Level 2:	$*3.09*	per kW of Maximum Demand
Customer Voltage Level 3:	$*5.93*	per kW of Maximum Demand

The Distribution Charges for the Large Economic Development Rate are equivalent to the Distribution Charges for Large General Service Primary Demand Rate GPD. The monthly charge per kW of Maximum Demand per calendar month may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities required to serve the customer and specified in the contract for electric service.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $*(0.73)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $*(0.55)* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Interruptible Service Provision

The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Production Capacity Charge specified in the Large Economic Development Rate.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule or require testing to demonstrate the customer's ability to meet the contracted Interruptible Service Capacity.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and the Company shall inform the customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-78.40)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-81.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges

Power Supply Standby Charges

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500.

Real Power Losses

Real Power Losses shall be measured based on the transmission loss factor of *2.01*% plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	*0.992%*
Customer Voltage Level 2	*1.313%*	*2.239%*
Customer Voltage Level 3	*3.366%*	*6.948%*

Delivery Standby Charges

System Access Charge:

$100.00 per generator installation per month

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge: $*5.93* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $*3.09* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $*0.90* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-83.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-82.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar -hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700.Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15%penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $*(0.73)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $*(0.55)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer’s billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-83.10)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-83.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges

Transmission Interconnect Credit: $*(0.90)* per kW of Maximum Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill *or a check* for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-84.00)

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$0.062470	$0.000000	*$0.062470*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-86.00)

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-85.00)

Monthly Rate (Contd)

Secondary Delivery Charge

System Access Charge: $10.00 per customer per month

Distribution Charge: $*0.082650* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Primary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$0.030658	$0.000000	*$0.030658*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Primary Delivery Charge

System Access Charge: $20.00 per customer per month

Distribution Charge: $*0.062986* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

(Continued on Sheet No. D-87.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Sheet No. D-90.10**

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.00)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after ***XXXXXX XX, 2024*****:**

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$10.39*	*$10.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$11.02*	*$11.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$11.64*	*$12.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$12.27*	*$13.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$12.90*	*$14.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$13.52*	*$14.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$14.15*	*$15.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$14.77*	*$16.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$15.40*	*$17.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$16.03*	*$18.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$16.65*	*$19.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$17.28*	*$20.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$17.90*	*$20.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$18.53*	*$21.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$19.16*	*$22.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$19.78*	*$23.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$20.41*	*$24.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$21.03*	*$25.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$21.66*	*$25.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$22.29*	*$26.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$22.91*	*$27.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$23.54*	*$28.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$24.17*	*$29.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$24.79*	*$30.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$25.42*	*$30.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$26.04*	*$31.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$26.67*	*$32.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$27.30*	*$33.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$27.92*	*$34.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$28.55*	*$35.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$29.17*	*$35.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$29.80*	*$36.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$30.43*	*$37.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$31.05*	*$38.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$31.68*	*$39.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$32.30*	*$40.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$32.93*	*$40.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$33.56*	*$41.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$34.18*	*$42.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$34.81*	*$43.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$35.44*	*$44.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$36.06*	*$45.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$36.69*	*$45.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$37.31*	*$46.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$37.94*	*$47.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$38.57*	*$48.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$39.19*	*$49.33*

(Continued on Sheet No. D-90.20)

M.P.S.C. No. 14 – Electric
Consumers Energy Company

Sheet No. D-90.20

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.10)

Monthly Rate (Contd)
Universal Unmetered Streetlighting Rates, effective for service rendered on and after *XXXXXX XX, 2024*:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$7.39*	*$7.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$8.02*	*$8.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$8.64*	*$9.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$9.27*	*$10.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$9.90*	*$11.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$10.52*	*$11.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$11.15*	*$12.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$11.77*	*$13.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$12.40*	*$14.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$13.03*	*$15.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$13.65*	*$16.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$14.28*	*$17.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$14.90*	*$17.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$15.53*	*$18.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$16.16*	*$19.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$16.78*	*$20.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$17.41*	*$21.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$18.03*	*$22.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$18.66*	*$22.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$19.29*	*$23.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$19.91*	*$24.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$20.54*	*$25.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$21.17*	*$26.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$21.79*	*$27.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$22.42*	*$27.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$23.04*	*$28.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$23.67*	*$29.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$24.30*	*$30.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$24.92*	*$31.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$25.55*	*$32.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$26.17*	*$32.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$26.80*	*$33.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$27.43*	*$34.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$28.05*	*$35.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$28.68*	*$36.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$29.30*	*$37.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$29.93*	*$37.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$30.56*	*$38.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$31.18*	*$39.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$31.81*	*$40.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$32.44*	*$41.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$33.06*	*$42.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$33.69*	*$42.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$34.31*	*$43.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$34.94*	*$44.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$35.57*	*$45.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$36.19*	*$46.33*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-91.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company

Sheet No. D-94.00

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-93.00)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine LED lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of LED lighting available under this rate.

E. For customer requested material requiring special order, an additional per luminaire per month charge may apply for procurement and material handling. The Company and the Customer shall mutually agree to the monthly charge prior to procurement and installation of the special order material.

F. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered LED Lighting option.

G. Any charges, deposits or contributions may be required in advance of commencement of construction.

H. At the Company's discretion, any fixture may be converted to LED at no cost to the customer. The replaced fixture will be moved to General Unmetered Light Emitting Diode Lighting Rate GU-LED upon completion of the installation and reconciliation of the community's streetlighting inventory for billing accuracy.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Company-Owned Conversion Credit:

A conversion credit may be available to Customers who converted to LED municipal streetlighting.

Customers who converted to LED streetlighting before April 1, 2018 are eligible for the following Conversion Credit per billing month beginning with the January 2021 billing month through the December 2028 billing month:

Fixture Credit per Luminaire: $*(8.11)* per month

(Continued on Sheet No. D-94.10)

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Sheet No. D-94.20**

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *XXXXXX XX, 2024*:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$10.39*	*$10.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$11.02*	*$11.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$11.64*	*$12.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$12.27*	*$13.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$12.90*	*$14.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$13.52*	*$14.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$14.15*	*$15.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$14.77*	*$16.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$15.40*	*$17.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$16.03*	*$18.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$16.65*	*$19.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$17.28*	*$20.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$17.90*	*$20.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$18.53*	*$21.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$19.16*	*$22.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$19.78*	*$23.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$20.41*	*$24.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$21.03*	*$25.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$21.66*	*$25.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$22.29*	*$26.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$22.91*	*$27.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$23.54*	*$28.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$24.17*	*$29.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$24.79*	*$30.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$25.42*	*$30.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$26.04*	*$31.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$26.67*	*$32.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$27.30*	*$33.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$27.92*	*$34.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$28.55*	*$35.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$29.17*	*$35.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$29.80*	*$36.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$30.43*	*$37.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$31.05*	*$38.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$31.68*	*$39.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$32.30*	*$40.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$32.93*	*$40.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$33.56*	*$41.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$34.18*	*$42.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$34.81*	*$43.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$35.44*	*$44.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$36.06*	*$45.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$36.69*	*$45.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$37.31*	*$46.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$37.94*	*$47.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$38.57*	*$48.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$39.19*	*$49.33*

(Continued on Sheet No. D-94.30)

M.P.S.C. No. 14 – Electric
Consumers Energy Company

Sheet No. D-94.30

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.20)

Monthly Rate (Contd)
Universal Unmetered Streetlighting Rates, effective for service rendered on and after *XXXXXX XX, 2024*:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$7.39*	*$7.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$8.02*	*$8.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$8.64*	*$9.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$9.27*	*$10.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$9.90*	*$11.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$10.52*	*$11.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$11.15*	*$12.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$11.77*	*$13.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$12.40*	*$14.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$13.03*	*$15.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$13.65*	*$16.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$14.28*	*$17.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$14.90*	*$17.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$15.53*	*$18.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$16.16*	*$19.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$16.78*	*$20.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$17.41*	*$21.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$18.03*	*$22.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$18.66*	*$22.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$19.29*	*$23.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$19.91*	*$24.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$20.54*	*$25.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$21.17*	*$26.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$21.79*	*$27.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$22.42*	*$27.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$23.04*	*$28.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$23.67*	*$29.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$24.30*	*$30.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$24.92*	*$31.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$25.55*	*$32.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$26.17*	*$32.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$26.80*	*$33.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$27.43*	*$34.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$28.05*	*$35.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$28.68*	*$36.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$29.30*	*$37.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$29.93*	*$37.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$30.56*	*$38.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$31.18*	*$39.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$31.81*	*$40.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$32.44*	*$41.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$33.06*	*$42.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$33.69*	*$42.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$34.31*	*$43.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$34.94*	*$44.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$35.57*	*$45.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$36.19*	*$46.33*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-95.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company

Sheet No. D-96.00

GENERAL SERVICE UNMETERED RATE GU

Availability:

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service:

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate:

Power Supply Charges:

Energy Charge:

Non-Capacity	Capacity	Total	
$0.074181	*$0.002717*	*$0.076898*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$*0.026587* per kWh for all kWh	

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-97.00)

RETAIL OPEN ACCESS RESIDENTIAL SECONDARY RATE ROA-R

(Continued From Sheet No. E-21.00)

RETAILER

Monthly Rate - Retailer:

Transmission Service:

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses of *6.948*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer:

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

ROA CUSTOMER

Monthly Rate – ROA Customer:

ROA System Access Charge, Distribution Charge, General Terms, Minimum Charge and Due Date and Late Payment Charge:

The System Access Charge, Distribution Charge, General Terms, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00. Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service shall pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA:

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge:

A $5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer’s previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule E2.5 D., Return to Company Full Service - Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer:

Service under this rate shall not require a ROA Service Contract between the Company and a ROA Customer.

RETAIL OPEN ACCESS SECONDARY RATE ROA-S

(Continued From Sheet No. E-23.00)

Metering Requirements:

The ROA Customer with a Maximum Demand of less than 20 kW shall be separately metered by a Wireless Under Glass Meter or an Energy Registering Meter, with or without maximum demand registers, of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company.

The ROA Customer with a Maximum Demand of less than 20 kW may elect to install an Interval Data Meter. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The requesting ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with a Maximum Demand of 20 kW or more shall be separately metered by a Wireless Under Glass Meter or an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

RETAILER:

Monthly Rate - Retailer:

Transmission Service:

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses of *6.948*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer:

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

(Continued on Sheet No. E-25.00)

RETAIL OPEN ACCESS PRIMARY RATE ROA-P

Availability:

Subject to any restrictions, this rate is available to any customer receiving service at a Primary Voltage for the delivery of Power from the Point of Receipt to the Point of Delivery and for resale service in accordance with Rule C4.4, Resale.

This rate is not available to a ROA-P Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer. This ROA Customer must take service under Retail Open Access Secondary Rate ROA-S.

This rate is not available for unmetered general service or for any unmetered or metered lighting service.

Service under this rate shall be separately metered. The Retailer shall deliver a flat, fixed amount of power every hour of every day.

Any ROA Customer whose monthly minimum Maximum Demand is less than 1,000 kW must utilize an Aggregator.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company shall not be required to, but may expand its existing facilities to make deliveries under this tariff. The ROA Customer and/or Retailer shall be liable for any and all costs incurred as a result of an expansion of facilities made to make deliveries under this tariff.

Metering Requirements:

The load under this tariff shall be separately metered by a Wireless Under Glass Meter or an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA customer shall be required to pay the System Access Charge, as provided for under the ROA customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

RETAILER

Monthly Rate - Retailer:

Transmission Service:

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses as shown below on the Company's Distribution System associated with the movement of Power and for compensation for losses.

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	*0.992%*
Customer Voltage Level 2	*1.313%*	*2.239%*
Customer Voltage Level 3	*3.366%*	*6.948%*

(Continued on Sheet No. E-27.00)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
ORDER Capacity Related Cost and Charge Calculation
Projected 12-Month Period Ending February 28, 2025

Case No.: U-21389
COMMISSION ORDER
Attachment C

Line No.	(a) Description	(b) Total Electric ($000)	(c) Capacity Charge	(d) Formula
1	Total Production Related Cost	$ 2,666,932		
2	Non-Capacity Related Cost:			
3	Fuel Expense	$ 1,039,289		
4	Purchased & Interchanged	593,953		
5	Energy Related Other O&M Expense	59,634		
6	PSCR Revenue Credits	(684,353)		
7	Non-PSCR Revenue Credits	(105,100)		
8	Transmission Expense	543,730		
9	Total Non-Capacity Related Cost	$ 1,447,152		Σ Lines 3:8
10	Total Capacity Related Cost	$ 1,219,780		Line 1 - Line 9
11	Offsets:			
12	Energy Market Sales	$ 1,967,929		
13	Off-System Energy Sales	12,000		
14	Ancillary Service Sales	11,874		
15	Bilateral Energy Sales	-		
16	Total Revenue	$ 1,991,803		Σ Lines 12:15
17	Related Fuel Cost	899,084		
18	Total Revenue Less Fuel Cost	$ 1,092,719		Line 16 - Line 17
19	Net Capacity Cost	$ 127,061		Line 10 - Line 18
20	Capacity Charge Demand (MW)		7,526	
21	Capacity Charge ($/MW-Day)		$46.25	[(Line 19 x 1,000) ÷ Line 20] ÷ 365
22	Capacity Charge ($/MW-Year)		$16,882.95	[(Line 19 x 1,000) ÷ Line 20]

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-21389

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on March 1, 2024 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 J. Brown

Brianna Brown

Subscribed and sworn to before me
this 1st day of March 2024.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024